

November 15, 2019

Via Hand Delivery & Electronic Mail

Adam Renfandt
Analyst, Public Utilities Division
North Dakota Public Service Commission
600 E. Boulevard, Dept. 408
Bismarck, ND 58505-0480
ndpsc@nd.gov

In re: Denbury Green Pipeline-North Dakota, LLC
Denbury Green Pipeline-Montana, LLC
Cedar Hills South Unit Lateral Pipeline Project
Case No. PU-19-294
Bowman & Slope Counties

Dear Mr. Renfandt:

In response to your October 21, 2019 letter, please find the following additional information, along with eight copies of each attachment referenced below, in the captioned matter:

1. **Request:** Update Appendix A map sets to show the proposed Project corridor and supplement the Application to include the following GIS layers:

Response: The Natural Resources Survey Corridor Maps in Appendix A show the proposed Project corridor which is shaded in pink. Denbury is evaluating the GIS data and will supplement the previously filed GIS data where necessary.

2. **Request:** Provide any agency correspondence that has been received since the filing.

Response: See Attachment 1.

3. **Request:** An agency letter from the North Dakota Geological Survey and the North Dakota Department of Environmental Quality needs to be sent. File both the letters sent and responses received with the Commission.

Response: See Attachment 2.

4. **Request:** Page 70 and 71 of the application discusses prairie dog colonies. Provide the names of the species that occupy the colonies.

Response: Pipeline maps in Appendix A show 2 prairie dog colonies (PD01 and PD02), but the NR Report does not discuss these colonies. According to the ND Fish and Game Department website, these colonies would consist of black-tailed prairie dogs (*Cynomys ludovicianus*).

5. **Request:** Exclusion area includes "areas where animal or plant species that are unique or rare to this state would be irreversibly damaged."
- a. The North Dakota Game and Fish's "Species of Conservation Priority" identifies animal species that are unique or rare to North Dakota (copy attached). If yes, the areas in the corridor and the buffer zones to protect the integrity of the areas must be identified on the map sets and discussed in the application.
 - b. The North Dakota Parks and Recreation Department's "ND Natural Heritage Inventory" identifies plant species that are unique or rare to North Dakota. If yes, the areas in the corridor and the buffer zones to protect the integrity of the areas must be identified on the map sets and discussed in the application.

Response:

- a. According to the NDGF's Species of Conservation Priority, the only Level I species along the pipeline route is the Greater Sage Grouse (*Centrocercus urophasianus*), which is present in far southwestern North Dakota. The preferred habitat is sagebrush, particularly big sagebrush, while silver sagebrush and rabbitbrush is utilized to a lesser extent, with riparian and upland meadows, irrigated and non-irrigated croplands, and pastureland habitats also used, especially for broodrearing. Potential Sage Grouse habitat is present along the pipeline route and Section 4, No. 10 of the Natural Resources Report makes the following recommendations:
 - i. To minimize impacts to the greater sage-grouse and their habitats, there should be no surface use within 2-miles of active leks or documented nest sites during the breeding and nesting season (March 1 to June 15).
 - ii. Areas of sagebrush disturbed during construction should be reclaimed with 10% cover of sagebrush plugs or seedlings.
 - iii. During the operations phase of the pipeline, maintenance activities should be restricted in sage-grouse breeding or nesting complexes between March 1 and June 15 during the hours of 8:00 pm to 8:00 am.

The Natural Resources Report lists the Gray Wolf (*Canis lupus*), the Northern Long-Eared Bat (*Myotis septentrionalis*), and the Whooping Crane (*Grus Americana*) as the only threatened or endangered species that are potentially present in the project area. Further, no threatened or endangered species or critical habitats were observed during the field surveys.

- b. No unique or rare plant species were identified.

6. **Request:** Page 13 of the Application indicates that an Emergency Response Plan and a Pipeline Integrity Management Plan is under development. File the completed plans with the Commission.

Response: These plans are required by PHMSA to be prepared prior to the start of operations. Denbury has prepared both plans that govern other pipeline operations and systems, and these plans will be used for the CHSU CO₂ Lateral Pipeline once it becomes operational. Copies of both plans are attached (Attachments 3 & 4).

7. **Request:** Page 15 of the Application indicates that site 32BO00245 is located in the right-of-way, and that SHPO proposed avoidance measures. When will Denbury know when this is an exclusion or avoidance area?

Response: Additional investigation of 32BO00245 was conducted and the results of that assessment and SHPO's concurrence of "No Significant Sites Affected" and Not Eligible for listing on the National Register of Historic Places was submitted to the PSC on November 12, 2019.

8. **Request:** Will the proposed project include block valves or any aboveground facilities in North Dakota? If yes, please update your map sets to include the locations. Also, include the GIS layer(s).

Response: No block valves. The only surface facilities will be Denbury's existing Miller Production Tank Battery.

9. **Request:** Provide the study that informed that "no known hibernacula" are located in North Dakota (see page 18 of the Application). Northern long-eared bats are listed as present in Bowman and Slope Counties. Did Denbury survey for them? Describe Denbury's plans to stop construction during certain seasons that are related to either their habitat or presence.

Response: Suitable winter habitat (hibernacula) includes large caves and mines and, as presented at <https://www.fws.gov/midwest/angered/mammals/nleb/nhisites.html>, no known hibernacula are located in North Dakota. Suitable winter habitat does not occur in the pipeline ROW, while nearby trees, including the Green Ash, and rocky outcrops can serve as suitable summer day roosts, but suitable habitat in the project area is minimal.

10. **Request:** Page 1 of the Natural Resources and Wetland Delineation Report indicates that SWCA conducted several "cursory" surveys and an assessment. What makes them cursory in nature? What would make them more complete?

Response: The "cursory" threatened and endangered field surveys refers to potential pipeline routes that were considered but later ruled out for one reason or another. The field survey findings presented in the Natural Resources Report is complete and additional surveys are not required to make them more complete.

11. **Request:** Provide a table showing the status of the issuance of each required permit, and the timeline to obtain each.

Response: See revised table (Attachment 5).

12. **Request:** With respect to the effects on public health and welfare, describe the difficulty of detecting leaks that are unique to a CO2 pipeline, the time it takes to detect a CO2 leak, the amount of components leaked, and the effect on public health and welfare of each component. Provide all studies Denbury or outside entities have conducted that have provided such information for either a catastrophic failure or a leak.

Response: See Attachment 6.

13. **Request:** File with the Commission the project control documents listed below. Include the project control documents that may have informed the Environmental Mitigation Plan provided in Appendix B of the application. For those not complete, provide the status, completion date(s), and the outstanding issue(s) that prevent completion.

- a. Emergency procedures plan
- b. 10-year spill history report
- c. Construction plan
- d. Erosion control plan
- e. Storm water pollution prevention plan
- f. Migratory Bird Treaty Act plan and training documents detailing the environmental training of contractors and construction crews on the proper identification of unique, rare, protected, or special bird species, their habitats, and correct procedures regarding a sighting
- g. Spill prevention and control plan
- h. Revegetation plan
- i. Weed management plan, and all county specific weed management plan(s)
- j. Dust control plan
- k. Environmental training plan
- l. Baseline soil analysis used for determining topsoil depth along the Project route

Response:

- a. The Emergency Response Plan (Attachment 3) includes and constitutes the emergency procedures plan.
- b. Denbury Green Pipeline – Montana, LLC and Denbury Green Pipeline – North Dakota, LLC have not had any spills.
- c. Generally described in the Environmental Mitigation Plan and illustrated in Appendix A as the Pipeline Schematics. The pipeline alignment sheets (Attachment 7) provides additional information for construction of the pipeline.
- d. The Erosion Control Plan is generally discussed in the Environmental Mitigation Plan (Appendix C), with more detail to be included in the Stormwater Pollution Prevention Plan.
- e. The Stormwater Pollution Prevention Plan will be prepared and included as part of the request for quotes package to be sent to potential contractors for bidding purposes.

- f. Migratory birds and suitable nesting habitat were observed throughout the survey area. In order to avoid unauthorized take of migratory birds and active nests, SWCA recommends conducting construction outside of the migratory bird breeding season as practicable. If construction occurs during the bird breeding season (February 1–July 15), SWCA recommends to either mow, maintain, or completely remove vegetation within the project construction area outside the migratory bird nesting season; conduct migratory bird nesting surveys 5 days prior to construction; or prepare a habitat mitigation plan for approval by the USFWS which, once approved, would allow for clearing active nests and habitat during any time of year. If active nests (i.e., nests with eggs or young) are identified, the USFWS should be notified.
 - g. Spill prevention and control requirements and procedures are included in the Stormwater Pollution Prevention Plan, the Environmental Mitigation Plan (Appendix C), and the Emergency Response Plan (Attachment 3).
 - h. Revegetation of disturbed areas is addressed in the Environmental Mitigation Plan (Appendix C) and the Stormwater Pollution Prevention Plan. Additionally, Denbury has developed specific Ecozone Reclamation Plans for the CHSU Lateral Pipeline (Attachment 8).
 - i. Denbury has developed a Noxious Weed Management Plan (Attachment 9) for the CCA Pipeline in Montana that the CHSU Lateral Pipeline will connect to. This plan will be revised to reflect the conditions in Slope and Bowman Counties by March 2020. In addition, the Natural Resources Report identifies state- and county-listed noxious weeds and indicates that noxious weeds were not observed during the field surveys.
 - j. Dust control procedures are discussed in the Environmental Mitigation Plan (Appendix C) and in the Stormwater Pollution Prevention Plan.
 - k. The Stormwater Pollution Prevention Plan requires training on stormwater management and best management practices at least annually, or when new personnel join the project, or if the results of routine inspections indicate the need for refresher or in-depth training.
 - l. Denbury contracted with Duraroot Environmental Consulting to conduct topsoil, vegetation, and aerial surveys of the CHSU Lateral Pipeline route. Topsoil depth measurements and visual classifications were made every 750 feet along the centerline of the pipeline route, while two topsoil samples per mile were collected and analyzed for chemical and physical parameters that may negatively impact reclamation efforts. A Topsoil Depth Table (Attachment 10) summarizes the topsoil depths and locations and was used in the preparation of a Topsoil Mapbook and an Interpolated Topsoil shapefile.
14. **Request:** File with the Commission a table showing Denbury's leak and spill history for the most recent 10 years.

Response: Denbury Green Pipeline – Montana, LLC and Denbury Green Pipeline – North Dakota, LLC have not had any spills.

In response to your November 14, 2019 email, Denbury does not currently have plans for any other PSC jurisdictional development in the area. If you have any questions, please feel free to contact me. Thank you.

Sincerely,

A handwritten signature in blue ink that reads "Wade C. Mann". The signature is fluid and cursive, with the first name "Wade" being more prominent than the last name "Mann".

Wade C. Mann

WCM/lh

cc: Mitch Armstrong (via email)
Rusty Shaw (via email)
Forrest Hudson (via email)
Jim Dawson (via email)

Attachment 1

From: Hicks, Bruce E. bhicks@nd.gov

Wed 1/2/2019 7:29 AM

To: Jim Dawson; Fried, Stephen J.

Subject: Denbury Green Pipeline-Montana, LLC's Carbon Dioxide Transmission Pipeline project

James,

Our office recently received notice that Denbury Green Pipeline-Montana, LLC is proposing a Carbon Dioxide Transmission Pipeline project from Fallon County, Montana to Denbury's Cedar Hills South-Red River "B" Unit in Bowman County, North Dakota. I have reviewed the pipeline route and I'm sure Denbury is already aware there are numerous oil and gas wells throughout the route, but there are a few plugged and abandoned wells that may not be on their radar. The location of the wells can be found by utilizing our GIS Map Server which can be found at:

<https://www.dmr.nd.gov/OaGIMSSub/viewer.htm> . Please let us know if you would like any additional information.

Sincerely,

Bruce E. Hicks

Assistant Director
Oil and Gas Division
Dept of Mineral Resources
North Dakota Industrial Commission
701-328-8020
bhicks@nd.gov
www.dmr.nd.gov/oilgas
Bismarck, ND 58505-0840

North Dakota Geological Survey



Edward C. Murphy - State Geologist

Department of Mineral Resources

Lynn D. Helms - Director

North Dakota Industrial Commission

www.state.nd.us/ndgs

December 21, 2018

Mr. James W. Dawson
SWCA Environmental Consultants
116 North 4th Street, Suite 200
Bismarck, ND 58505-0840

Re: Denbury Green CO₂ Pipeline Corridor Review Comments

The North Dakota Geological Survey appreciates the notification and opportunity to review and provide comment on the proposed oil and gas energy infrastructure development project. Your comment solicitation letter of November 30, 2018 was reviewed by our office on December 18, 2018. We dropped in the North Dakota portion of the alignment of the proposed pipeline route on our landslide base maps from the GIS layer provided to us and compared it to the locations of landslides that have been identified by detailed mapping work previously completed by our office (Moxness, 2018, Murphy, 2016). Additionally, the entire North Dakota portion of the proposed pipeline route was evaluated by reviewing historical aerial photography from July, 1957, LiDAR elevation data collected between the fall of 2015 and spring of 2016 and National Agriculture Imagery Program (NAIP) aerial imagery from 2014 for the identification of any more recent landslide areas.

We noted that the proposed pipeline route generally passes along areas that are generally topographically flat with little relief and consequently are generally free of landslides. However, a few areas of concern were noted at the locations of stream crossings and where topographic conditions suggest additional engineering review should be considered (Figure 1, Attached). The approximate locations of these areas are listed below in Table 1:

Table 1. Location of Areas of Concern along Proposed Pipeline Route

No.	County	Description	Longitude	Latitude
1	Slope	West Facing Slope with Collapse Topography	-104.037021	46.291616
2	Bowman	West Facing Slope at Little Beaver Creek Meander	-103.975638	46.271727
3	Bowman	North Facing Slope Adjacent to Slough	-103.949745	46.245374
4	Bowman	Erosional\Slide Areas along West and East Pipeline Corridor	-103.939319	46.224228

Landslide maps and data, along with LiDAR elevation data sets and mapping products for the project area are available on our website at: <https://www.dmr.nd.gov/ndgs/SurfaceMap/SurfaceMap.asp?source=landslide24k>

Careful examination of actual pipeline routes and evaluation of applicable construction practices throughout the proposed pipeline corridor should be continued. You may also contact our offices directly, with any additional questions or comments, at (701) 328-8000.

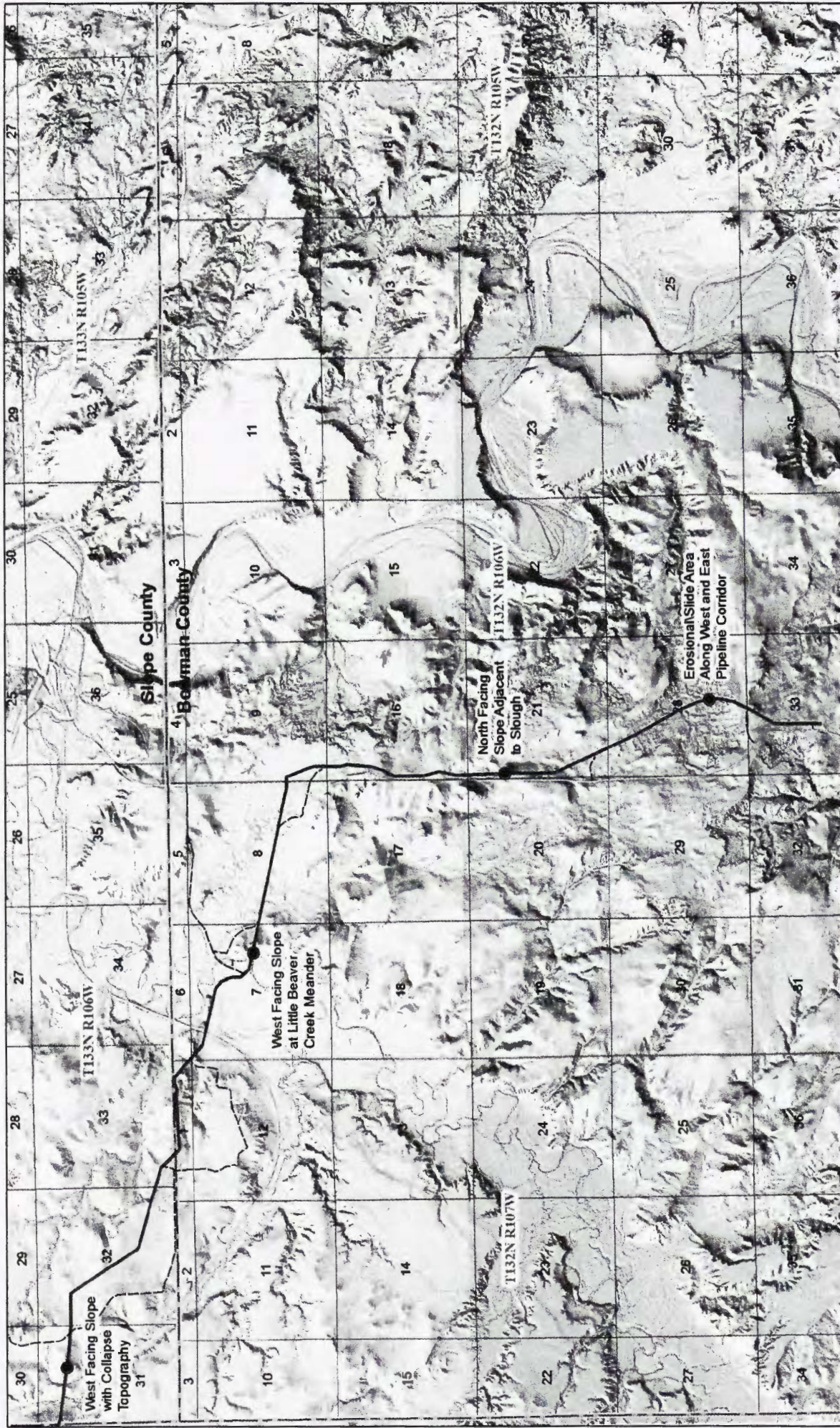
Sincerely,

North Dakota Geological Survey:

Fred Anderson
Geologist
fjanderson@nd.gov

FJA\Attachment

Proposed Denbury Green CO₂ Pipeline Route - Location Map



- Areas of Concern
- Pipeline Centerline

Figure 1: Denbury Green CO₂ Proposed Pipeline Route Areas of Concern - Location Map



Emergency Response Plan

**Rocky Mountain Region; Lost
Cabin Plant and Greencore,
Grieve, and Riley Ridge
Pipelines**

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1. Applicability

- Gathering
- Processing
- Regulated Onshore Pipelines

2. Scope

This procedure provides guidelines for developing an Emergency Response Manual and National Incident Management System (NIMS) to manage an emergency and return operations to normal. The Emergency Response Manual gives specific instruction about responding to events on or near a facility, and provides for communications with employees, government agencies, and the public to minimize any hazard resulting from a facility emergency.

3. Core Information and Requirements

3.1. General

- 3.1.1. Every Company gathering, processing, and transmission area/facility must have a current Emergency Response Manual that contains procedures specific to that area/facility.
- 3.1.2. Emergencies are usually reported to the Denbury Control Center (DCC) by a private citizen, a public emergency response officer, or a field employee. When informed of an emergency by a private citizen, DCC personnel will obtain as much detail as possible and call a designated field employee to investigate the status. Upon being notified by the DCC, employees will respond to the emergency immediately.
- 3.1.3. When design or operational limits have been exceeded but the occurrence does not meet the level of an emergency situation, it shall be referred to as an Abnormal Operation. Refer to [O&M Procedure 1902 – Abnormal Operation](#).
- 3.1.4. When Company facilities are involved in an emergency, Company personnel shall take the appropriate action (e.g. emergency shutdown or pressure reduction) to safeguard human life first and then protect Company and private property and maintain or restore operations, if possible.
- 3.1.5. Field personnel shall immediately communicate information about the emergency to a supervisor, who will promptly call the DCC. In the event the supervisor cannot be reached immediately, field personnel will contact the DCC. The DCC will initiate the appropriate notification system (refer to [O&M Procedure 0159 – Emergency Reporting and Investigation](#)).

3.2. National Incident Management System

The NIMS is an organized, coordinated management system established to respond to an emergency and is typically comprised of personnel assigned to perform the functions listed below (titles may vary). These functions depend on available personnel, facility size, and emergency event level:

- The Incident Commander will designate a qualified individual (example: HSE or Operations personnel) to ensure site, public and employee safety; establish the site safety plan; coordinate environmental response; maintain contact with the area/region HSE Project Manager and other HSE personnel as required; maintain contact with local, state and federal emergency response organizations or other agencies as necessary
- The On-Site Coordinator handles on-site activities
- The Logistics/Planning Coordinator obtains necessary response equipment, materials, contractors, other company personnel, etc.
- Financial/Administration arranges for humanitarian assistance, lodging, meals, etc. and manages purchase orders, contacts, etc.

3.3. Roles and Procedural Duties

3.3.1. Incident Commander

The Incident Commander is responsible for managing the emergency response and will coordinate these activities:

- Establishing a command post, assembling the NIMS team and assigning team member responsibilities
- Assessing Priorities: Safety first, Stabilization second
- Accounting for locations of all personnel who were in the area/facility at the beginning of the emergency
- Implementing the site-specific Emergency Response Plan (ERP)
- Providing on-site supervision of response activities
- Assessing and deploying needed resources and coordinating activities
- Serving as or providing for an emergency event safety officer to be responsible for preventing injuries and/or death
- Maintaining communications with the Regional Operations Manager, DCC, Crisis Management Team (CMT), and HSE throughout the response
- Coordinating activities of and responding to outside agencies, the CMT (represented by the Emergency Response Coordinator), and the Accident Investigation Team
- Coordinating response to initial contacts with local press and governmental agencies
- Returning the facility to normal service
- Ensuring all reports associated with the emergency have been completed
- Ensuring an investigation is conducted to determine the event's root cause and to develop corrective actions to prevent recurrence
- Coordinating the emergency response critique with the post-investigation team

3.3.2. Employee Detecting or Receiving Emergency Notification

The first employee detecting or notified of an emergency is responsible for:

- Assessing the threat to life and health
- If injuries are present calling 911
- Notifying the operations supervisor or the DCC
- Initiating the site-specific ERP

3.3.3. Person in Charge

The person in charge is any employee with operational responsibility who has received training in the NIMS, emergency response or local training per the site-specific ERP. The person in charge must:

- Have access to this procedure and the site-specific ERP
- Immediately initiate the site-specific ERP and notify the supervisor or DCC
- Gather information on the emergency
- Implement actions to stabilize the situation, coordinate and document all telephone calls, conversations, pressures, etc. pertinent to the emergency until relieved of the responsibility

3.4. Emergency Response Manual

3.4.1. Emergency Response Procedures

The Emergency Response Manual shall contain procedures for responding to, investigating, and correcting the cause of the following types of emergencies, where applicable:

- Catastrophic failure and damage
 - Fire located near or directly involving a pipeline facility
 - Explosion occurring near or directly involving a pipeline facility
 - Accidental release of CO₂ or Gas
- Operational failure causing a hazardous condition including:
 - Non-scheduled releases from stationary or mobile sources
 - Major accidents involving Company vehicles or contractor-owned equipment
 - Bomb threats
 - Gas/CO₂/H₂S detected inside or near a building
 - Threats against employees or Company facilities
 - Fatalities or multiple hospitalizations involving employees or the public
 - Unauthorized active encroachments on Company property
 - Loss of communications
 - Unintended valve closures
 - Pressure or flow rate outside of normal operating limits
- Natural disasters affecting pipeline facilities including:
 - Floods
 - Damaging storms (hurricanes, tornadoes, etc.)
 - Weather extremes (cold, blizzards, heat)
 - Lightning and wildfires

3.4.2. Emergency Response Plan (ERP)

Area/facility personnel will develop a site-specific ERP using [O&M Forms OM1900-01 through OM1900-13](#) as guidelines (refer to [Section 5 – Documentation](#) for a detailed, linked list of applicable forms).

The information required in the ERP is listed in [Section 5 – Documentation](#). In addition, the ERP should cover all types of emergencies listed in [Subsection 3.4 – Emergency Response Manual](#), as well as all the details listed below.

The ERP will include details to:

- Provide facility plot plan or pipeline map indicating ESDs, evacuation routes, first aid stations, eye washes/showers, fire extinguishing equipment and meeting locations
- Establish emergency escape procedures and routes
- Establish and maintain communication with parties listed on [O&M Form OM1900-04 – Emergency Contacts](#)
- Identify labor, materials and equipment
- Make the area safe (people first, then property)
- Provide primary and alternate meeting locations for employees and contractors after evacuation
- Identify O&M procedures for use during emergency response
- Isolate the area/facility
- Handle hazardous substances using Material Safety Data Sheets (MSDS)
- Return the facility to service in conformance with Company O&M procedures

3.4.3. Denbury shall review the procedures to be used in case of an emergency at intervals not exceeding 15 months, but at least once each calendar year. Whenever deficiencies are discovered, the ADC will approve necessary changes per [O&M Procedure 0000 – Action Decision Committee](#).

3.5. Determining Reporting Levels and/or Criteria

Events will be classified into one of two categories by the Pipeline Foreman or the first available Pipeliner at the time of the incident.

- **Level I Events** shall include pipeline damage, leaks, fires, or other types of releases that **DO NOT** pose any immediate threat to human life or health.
- **Level II Events** shall include pipeline damage, leaks, fires, or other types of releases that **DO** pose an immediate threat to human life or health.

3.6. Liaison with Public Officials

Establish and maintain liaison with appropriate emergency responders. Refer to [O&M Procedure 0232 – Damage Prevention and Public Awareness](#) for details.

3.7. Media Response

A designated spokesperson at the site will handle initial communications with the public and the media. The designated spokesperson may give the media at the scene a brief outline of the known facts.

When reporters arrive, the designated supervisory person should check credentials to confirm they are reporters and assign someone to escort them to an off-site media center.

3.8. Post-Emergency Investigation and Critique

Emergencies will be investigated per [O&M Procedure 0159 – Emergency Reporting and Investigation](#).

The post-emergency investigation will determine the emergency's root cause and recommend any needed changes to prevent recurrence.

The critique will assess emergency response effectiveness, the NIMS and the action plan to determine whether the ERP needs to be improved.

3.9. Emergency Response Manual Reviews/Drills

Foremen will schedule annual area/facility training reviews and/or drills to determine effectiveness of the site-specific Emergency Response Manual. Reviews and drills will be defined in the site-specific ERP and documented using [O&M Form 1900-11 – Emergency Drill](#).

Document reviews and drills and keep on file for 5 years.

3.10. Returning Facility to Service

Establish procedures to return equipment or facility to normal operations following an emergency.

3.10.1. Person in Charge of Equipment/Facility Repair

When the emergency ends, or as soon as practical, determine and notify the DCC of the following:

- The extent of damage
- An estimate of time required to repair the equipment/ facility

3.10.2. Person in Charge of Facility

Call personnel and have them report to duty when they are needed to:

- Locate pertinent material available from stock or suppliers
- Arrange for contract equipment and personnel
- Prepare plans for returning the facility to service
- Assist in any other activities involving the emergency
- Organize and dispatch work crews and contract equipment to the facility as needed
- Restore facility to service as soon as repairs can be made safely and in conformance with established procedure
- Evaluate the failure cause and provide a written plan to prevent a reoccurrence of the emergency

- Prepare Pre Start-Up Safety Review per the requirements of [O&M Procedure 0156 – Pre-Startup Safety Reviews](#)
- Perform Management of Change per the requirements of [O&M Procedure 0155 – Management of Change](#)

3.10.3. Denbury Control Center (DCC)

The DCC will ensure that contact is established between the Company and representatives of customer companies and will:

- Notify customer companies of any emergency that might affect delivery to them
- Keep affected customer companies informed
- Notify customer companies and suppliers when delivery will be curtailed or interrupted
- Notify customers if reduced delivery will continue
- Notify customer companies and suppliers when repair is completed and the Company is ready to restore service
- Restore service in conformance with customers' and suppliers' contract information files after Regional Operations Manager approval

4. Training

4.1. Training Requirements

4.1.1. Foremen will ensure that the ERP is reviewed annually with personnel to verify emergency training is effective. New employee orientation shall include training on the ERP.

Personnel review and training verification will be documented using [O&M Form 1900-11 – Emergency Drill](#). A recommended verification method is used to conduct discussions of employees' emergency response to scenarios specific to each area/facility.

4.1.2. Every employee identified in the ERP shall be current on emergency response training, including the appropriate level of Hazwoper training.

4.1.3. Once a year, each Denbury Operations District will host a table-top drill for pipeline personnel. During the table-top drill, the foremen will review performance, make appropriate changes, and verify that all pipeline personnel maintain a thorough knowledge and understanding of policies and procedures. Any deficiencies must be identified and investigated ensure effectiveness.

[O&M Form 1900-11 – Emergency Drill](#) will be maintained at the Operations District Office for 5 years.

4.2. Training Content

At a minimum, training shall include the following:

- Understanding roles in various emergency response scenarios
- Using Company communication systems
- Locating isolation valves
- Responding to specific failures
- Responding to media questions
- Where to meet in the event roads to the station are impassable and/or communications are unavailable
- Control, containment, and clean-up procedures
- Know the characteristics and hazards associated with the product being transported.

5. Documentation

The Operations District Emergency Response Manual should consist of the following completed Forms and site-specific written procedures:

- [O&M Procedure 1900 – Emergency Response](#)
- [O&M Procedure 1902 – Abnormal Operation](#)
- [O&M Procedure 0512 – Severe Weather Operating Plan](#)
- [O&M Procedure 0159 – Emergency Reporting and Investigation](#)

- [O&M Form OM1900-01 – Information Contacts and Verification of Plan](#)
- [O&M Form OM1900-02 – Facility Personnel Responsibilities](#)
- [O&M Form OM1900-03 – Primary Notification Contacts](#)
- [O&M Form OM1900-04 – Emergency Contacts](#)
- [O&M Form OM1900-05 – Chronological Record of Emergency: First Facts](#)
- [O&M Form OM1900-06 – Emergency Shutdown Device Locations](#)
- [O&M Form OM1900-07 – Facility Isolation](#)
- [O&M Form OM1900-08 – Bomb Threat Checklist](#)
- [O&M Form OM1900-09 – On Site Emergency Response Equipment](#)
- [O&M Form OM1900-10 – Contractors and Available Equipment](#)
- [O&M Form OM1900-11 – Emergency Drill](#)
- [O&M Form OM1900-12 – Procedures for Critical Operations before Evacuation](#)
- [O&M Form OM1900-13 – Emergency Escape Procedures](#)
- Description of Facilities
- Steps to Take for Catastrophic Damage & Failure, Operational Failure Causing a Hazardous Condition, and Natural Disasters
- SPCC Plan (Insert SPCC Plan or describe location of plan)
- Plot Plan and/or Pipeline Map (Identify locations of ESD, evacuation routes, fire extinguishing equipment, assembly after evacuation, first aid stations, fire blankets, eyewash stations, showers, fences, personnel gates, assembly areas, H₂S monitor lights, alarm horn or light, SCBA units)

The person in charge shall ensure that all calls, conversations, pressures, etc. pertinent to any emergency are documented per this procedure.

6. References

- 29 CFR Part 1910.119 (PSM)
- 40 CFR 68 (RMP)
- 49 CFR Part 192.605
- 49 CFR Part 192.615
- 49 CFR Part 195.402
- 49 CFR Part 195.403
- [O&M Procedure 0155 – Management of Change](#)
- [O&M Procedure 0156 – Pre-Startup Safety Reviews](#)
- [O&M Procedure 0159 – Emergency Reporting and Investigation](#)
- [O&M Procedure 0232 – Damage Prevention and Public Awareness](#)
- [O&M Procedure 1902 – Abnormal Operation](#)
- [O&M Form OM1900-01 – Information Contacts and Verification of Plan](#)
- [O&M Form OM1900-02 – Facility Personnel Responsibilities](#)
- [O&M Form OM1900-03 – Primary Notification Contacts](#)
- [O&M Form OM1900-04 – Emergency Contacts](#)
- [O&M Form OM1900-05 – Chronological Record of Emergency: First Facts](#)
- [O&M Form OM1900-06 – Emergency Shutdown Device Locations](#)
- [O&M Form OM1900-07 – Facility Isolation](#)
- [O&M Form OM1900-08 – Bomb Threat Checklist](#)
- [O&M Form OM1900-09 – On Site Emergency Response Equipment](#)
- [O&M Form OM1900-10 – Contractors and Available Equipment](#)
- [O&M Form OM1900-11 – Emergency Drill](#)
- [O&M Form OM1900-12 – Procedures for Critical Operations before Evacuation](#)
- [O&M Form OM1900-13 – Emergency Escape Procedures](#)
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1. Applicability

- Gathering
- Processing
- Regulated Onshore Pipelines

2. Scope

This procedure provides guidelines for identifying, responding to, investigating the cause of, correcting, and documenting abnormal operation. It also establishes a method of review and evaluation of the Company’s response to abnormal operation.

3. Core Information and Requirements

Pipeline safety regulations require operators to have and to follow written procedures for responding to, investigating, and correcting the cause of abnormal operation. Those must include procedures for notifying appropriate responsible Company personnel to determine the continued integrity and safe operation of the pipeline when abnormal operation occurs. Finally, operators must periodically review their response to abnormal operation to determine the effectiveness of those procedures.

3.1. Identifying Abnormal Operation

Abnormal operation is not in itself an emergency. Abnormal operation occurs when operating conditions exceed operating design limits and any of the following occur:

- Unintended closure of valves or shutdowns (e.g. mainline valve closure)
- Increase or decrease in pressure or flow rate outside normal operating limits (e.g. regulator failing open)
- Loss of communications (e.g., Denbury Control Center (DCC) SCADA system communications loss for longer than DCC procedural time limits)
- Operation of any safety device, improper operation of any safety device, or operation outside of design parameters of any safety device (e.g. relief valve not resetting)
- Any event that results in a hazard to person or property due to a malfunction of a component, human error, or deviation from normal operations

3.2. Abnormal Operation within the Denbury System

Surge on a CO₂ pipeline, resulting in a pressure that would be 110 percent of MOP is not possible; therefore, design limits will not be exceeded.

3.3. Unintended Closure of Valves or Shutdowns

The Company will respond to, investigate, and correct the cause of unintended closure of valves or shutdowns as follows:

- 3.3.1. The DCC controller will determine if the unintended closure or shutdown was caused by a surge or other abnormal condition along the pipeline.
- 3.3.2. The DCC controller will determine if the unintended operation or shutdown came from the DCC, SCADA, or the field.
- 3.3.3. The DCC will contact the Pipeline Foreman or in the event the DCC cannot reach the Pipeline Foreman, the Pipeline Superintendent to discuss the unintended valve closure. If pipeline or customer operation is impacted and the Pipeline Foreman or Pipeline Superintendent determines that it is safe (a review of pressures and flows along the pipeline is required) to return the valve to its former status, the valve can be operated. The DCC controller will monitor data more closely until an investigation is complete. Further investigation is required at the DCC and in the field. The DCC will conduct an investigation in conformance with DCC procedures.
- 3.3.4. Locally, the Pipeline Foreman will investigate the unintended closure. The DCC will be informed of such investigation activities in the field. Customers impacted by the investigation will be notified of investigation activities. The investigation will include a thorough check of local and SCADA controls to determine if security could have been breached.
- 3.3.5. If a problem is found, repair procedures will be initiated and documented in the station log locally and at the DCC in conformance with DCC procedures.
- 3.3.6. If no problem is found, details of the investigation will be documented in the station log locally and at the DCC in conformance with DCC procedures.
- 3.3.7. After the initial investigation to gather pertinent facts and any necessary repairs are completed, the valve can be returned to normal service. The root cause investigation may proceed and conclude after the valve has been placed in service. Document the date and time in the station log locally and at the DCC per DCC procedures. [O&M Form OM0100-45 – Event/Incident Investigation Summary](#) must be filled out.

3.4. Increase or Decrease in Pressure or Flow Rate outside Normal Operating Limits

The Company will respond to, investigate, and correct the cause of increase or decrease in pressure or flow rate outside normal operating limits.

- 3.4.1. If an unexplained pressure change should occur on the mainline, the DCC controller should:
 - 3.4.1.1. View other pressure and flow points along the pipeline.
 - 3.4.1.2. Call the Pipeline Foreman or his/her designee.
 - 3.4.1.3. The DCC controller shall monitor the situation closely for at least four hours and Denbury pipeline personnel shall investigate the affected section of pipeline.
 - 3.4.1.4. Upon verification by field operating personnel of a CO₂ or Natural Gas release, block valves on both sides of the suspected leak location shall be closed.
 - 3.4.1.5. The DCC controller will contact customers whose operations will be affected by the shutdown.
 - 3.4.1.6. When Gas Control identifies an MAOP Exceedance on Natural Gas Transmission Lines, information about the exceedance shall be communicated to the Regulatory Group within 24 hours. For details on the reporting criteria, refer to [O&M Procedure OM0219 - DOT and State Pipeline Reports](#), sub-section "Gas Transmission MAOP Exceedance"
 - 3.4.1.7. In the event of a release, repair procedures will be initiated in a timely manner.
- 3.4.2. The DCC monitors all of the product quality and analyzers. A high moisture level means there is an operational problem with the dehydration facility or the analyzer is malfunctioning. The DCC will contact field personnel when moisture rises above the High Alarm.

3.4.2.1. When the moisture level goes below the High Warning, abnormal operation ends.

3.4.2.2. All events and actions will be documented in the DCC per DCC procedures and locally on [O&M Form OM0100-45 – Event/Incident Investigation Summary](#) and other forms as applicable.

3.5. Loss of Communications

The Company will respond to, investigate, and correct the cause of loss of communications.

Outages less than four hours are a part of normal operations. Outages that are greater than four hours require arrangements to be made for data to be collected for the DCC.

3.6. Operation of Any Safety Device

The Company will respond to, investigate, and correct the cause of operation of any safety device outside of design limits.

If activation of the PSRV is not at the set pressure, the PSRV will be recalibrated and/or replaced.

3.7. Any Other Malfunction of a Component, Deviation from Normal Operation, or Personnel Error that Could Cause a Hazard to Persons or Property

The Company will respond to, investigate, and correct the cause of any other malfunction of a component, deviation from normal operation, or personnel error that could cause a hazard to persons or property.

3.8. Checking Variations

The Company checks variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

The DCC will closely monitor all SCADA points pertinent to the abnormal operation for at least 24 hours.

3.9. Correcting Variations

Correcting variations from normal operation of pressure and flow equipment and controls shall be accomplished using Company procedures.

The DCC will monitor the location more closely for at least 24 hours following the outage.

3.10. Notifying Responsible Operator Personnel When Notice of an Abnormal Operation is Received

In the event the DCC receives a notice of an abnormal operation, the DCC will notify the responsible Denbury personnel as provided in the previous sections of this document.

Communication methods from the DCC will be conducted in conformance with their existing procedures.

3.11. Periodic Review

Denbury will conduct a periodic review of the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

The Pipeline Foreman shall annually review all responses conducted to investigate and or correct abnormal operations experienced on the pipeline covered in this Manual. The DCC will provide the information for this review when requested by the Pipeline Foreman. At a minimum, the Pipeline Foreman will consider and/or document the following:

- Dates of abnormal operations
- Brief descriptions of abnormal operations
- Locations of abnormal operations
- Pipeline systems involved in abnormal operations
- Method of abnormal operation detection
- Personnel receiving and responding to abnormal operation
- Time frame for the correction of abnormal operation
- Lessons learned or opportunities to improve the performance of personnel in the response to the abnormal operation

4. Training

Training occurs annually, not to exceed fifteen months, in conjunction with periodic review.

5. Documentation

Annual reviews of responses conducted to investigate and/or correct abnormal operations experienced on the pipeline covered in this Manual will be documented on [O&M Form OM0100-45 – Event/Incident Investigation Summary](#), and maintained at the Operations District Office, for 5 years plus current.

Documentation at the DCC is per DCC procedures. Data collected shall be recorded in the station logbook and [O&M Form OM0100-45 – Event/Incident Investigation Summary](#) will be filled out.

6. References

- 49 CFR Part 192.605 (c)(1)(2)(3)(4)
- 49 CFR Part 195.402 (d)
- [O&M Procedure 0155 – Management of Change](#)
- [O&M Procedure 0159 – Emergency Reporting and Investigation](#)
- [O&M Procedure 0214 – Reporting Pipeline Safety-Related Conditions](#)
- [O&M Procedure OM0219 - DOT and State Pipeline Reports](#)
- [O&M Procedure 1400 – Records Retention by O&M Procedure](#)
- [O&M Procedure 1900 – Emergency Response](#)
- [O&M Form OM0100-45 – Event/Incident Investigation Summary](#)

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1. Applicability

- Gathering
- Processing
- Regulated Onshore Pipelines

2. Scope

Initiate this plan any time severe weather may prevent employees from reporting to a station. The Pipeline Superintendent or designated person in charge is authorized to initiate and terminate the Severe Weather Operating Plan and to determine necessary variations from the plan based on local conditions.

Weather conditions outside the local area (e.g. major market areas, supply areas, or other pipeline districts) may prompt implementing the plan in that area. The Regional Operations Manager or the Vice President – CO₂ Supply and Pipelines may direct an area to initiate or terminate the plan.

3. Core Information and Requirements

This procedure does not replace the Emergency Plan, but is intended to assist in preventing emergencies. Refer to [O&M Procedure 1900 – Emergency Response](#) if an emergency develops and in the event of a communication, SCADA, or data control failure.

Arrange for enough company vehicles to be available to ensure prompt response of emergency call-out personnel and facilities access.

Shutdown pump stations in conformance with station shutdown procedures. Notify the DCC with times and dates of shutdown.

3.1. Notification

The location will notify the Pipeline Superintendent and DCC when implementing and terminating this plan and any necessary variations from the formal plan.

The location will also notify adjacent locations when the plan is in effect. Where severe weather may affect sales facilities or other operators or producers, the DCC will establish lines of communication to those affected to allow prompt response to avoid an emergency.

3.2. Cold Weather and Blizzard Procedures

3.2.1. Preparedness

Contact public officials to determine responsibility for reporting road conditions and for road clearing.

Be sure emergency equipment is available and in good condition.

3.2.2. Implementation

Company vehicles may be provided to employees to ensure access to Company facilities during severe weather.

The following procedures may prevent freeze-up problems during cold weather conditions. Follow at management's discretion.

3.2.2.1. Oil System

Install a portable steam heater to help keep engine temperatures higher during periods the engine is not running. Idle engines during off-line periods to keep oil at a higher temperature.

Portable heaters may be used to heat the bases of oil storage tanks to keep oil temperature above the pour point and insulate aboveground lines to prevent congealing.

3.3. Thunderstorms, Wind Storms, Tornadoes

3.3.1. Preparedness

Periodically check and test emergency generators, batteries and power supplies to verify operation.

3.3.2. Implementation

Increase surveillance of facilities during unusual operating conditions. If a power outage occurs, activate emergency power systems.

3.4. Floods and Hurricanes

3.4.1. Preparedness

Review transportation routes to determine accessible routes to Company facilities.

3.4.2. Implementation

Provide Company vehicles to employees as needed to ensure access to Company facilities affected by high water.

3.4.3. Terminating the Plan

Notify the DCC with times and dates of start-up. The DCC will notify all parties alerted under this plan of its termination.

4. Training

Review this information as necessary before performing the procedure.

5. Documentation

The DCC will document the time and date upon implementation and termination of this plan.

6. References

- [O&M Procedure 1900 – Emergency Response](#)

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1. Applicability

- Gathering
- Processing
- Regulated Onshore Pipelines

2. Scope

This procedure applies to Company personnel, operations and locations, and contractors (and their subcontractors) and contract employees (refer to [HSE Guidelines for Contractors](#)) when an undesired event occurs.

3. Core Information and Requirements

An undesired event is an event that results in;

- Harm to people, fatalities involving Company employees and contractors, lost work days and/or modified duty days associated with injuries and illnesses, Occupational Safety and Health Administration (OSHA) recordable Incidents, and first aid cases

- Damage to Company and/or third party (including customer's) facilities, equipment, property, vehicles (facilities can include pipelines and associated equipment)
- Environmental impacts, an unexpected release of a chemical substance, gas or loss of product into the workplace or environment
- Unintended operational process and/or customer interruption
- A serious or potentially high loss near miss that could have resulted in any of the above under slightly different circumstances (as determined by the Health, Safety, and Environmental [HSE] representative or the affected area's senior Company official). Refer to the [HSE Handbook](#).
- A pipeline Safety-Related Condition meeting the requirements of [O&M Procedure 0214 – Reporting Pipeline Safety-Related Conditions, Subsection 3.1.1 – Reporting Safety Related Conditions](#).

The Company requires internal reporting and investigation of any undesired event. Agencies that require reporting may include; U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT), Occupational Safety and Health Administration (OSHA), Environmental Protection Agency (EPA), state and local agencies. The Company uses an incident tracking database and various forms for reporting, tracking, investigating and documenting undesired events.

3.1. Immediately, upon discovery of an undesired event:

- Determine whether there is a hazard to persons or property.
- Take whatever steps are necessary to make the immediate situation safe.
- Determine whether any water bodies have been impacted; if yes, notify Supervisor and HSE immediately.
- Determine if the event fits accident/incident criteria as defined in [P0010 – Master Glossary](#) and [Subsection 5.1 – Immediate Report to the National Response Center \(NRC\)](#), if yes, notify Supervisor, Pipeline Regulatory, and HSE immediately.
- Initiate an emergency conference call including all applicable workgroups; Operations, DCC, HSE, Pipeline Regulatory, etc.
- Follow all applicable Company procedures.

3.2. Company personnel identifying an event affecting pipeline operations will:

- First, notify their Supervisor; if the Supervisor cannot be immediately reached, contact the DCC.
- Operations Management or the HSE representative will notify DCC and Pipeline Regulatory of any event that they consider significant or meeting the criteria listed in [Section 5.1 – Immediate Report to the National Response Center \(NRC\)](#) and determine event classification using [Attachment 1 – Event Classification](#). Refer to [Attachment 2 – Initial DCC Notification Checklist \(Sample\)](#) for baseline information requirements.

DCC personnel will initiate the Emergency Response process, which will notify appropriate Company personnel as applicable.

During emergency response conference calls, the appropriate Company personnel will determine immediate actions and formulate a plan of action. The on-site Company representative or designee will be asked to give details about the event.

Appropriate Company personnel will issue an update message to schedule additional conference calls or conclude the event.

Company personnel will investigate the event in conformance with [Section 6 – Investigation](#).

3.3. Determining Emergency Response Notification Levels

The DCC will issue notification for any event associated with a Company operation, including events incurred by third party contractors working for the Company.

Refer to [Attachment 1 – Event Classification](#) for notification levels.

4. HSE Reporting Requirements

See [HSE Policy 0139 - Emergency Response Guidelines](#) for additional actions taken for each phase of an event.

4.1. Immediate Report to the National Response Center (NRC)

EPA reportable events shall be reported to the NRC.

When any portion of an underwater pipeline is exposed or constitutes a navigation hazard in the Gulf of Mexico and its inlets, a member of the Company's HSE department shall be responsible for reporting the event to the NRC as soon as practicable but no longer than 24-hours after discovery.

NRC reports shall be made within the applicable reporting time limit telephonically by dialing 1-800-424-8802 or electronically at <http://www.nrc.uscg.mil/>.

When the report is made electronically, the NRC should send the reporting party a confirmation by e-mail within 45 minutes of receiving the online report. If an e-mail confirmation is not received within 45 minutes, the reporting party will call 1-800-424-8802 to ensure that the NRC has received the report.

A member of the HSE department shall be responsible for reporting EPA-reportable events within 1 hour of the event occurrence.

Each report shall include the following;

- The name of the Operating company
- Name(s) of person making report and their telephone numbers
- The location of the Incident or Accident (the county that the Incident/Accident occurred in, the nearest town and/or crossroads nearest the Incident)
- The time of the Incident
- The number of personal injuries or fatalities, if any
- The phone number of on-site Company contact
- Quantity of gas or other product released, if known
- Estimated property damage
- Other significant facts that are known and the extent of the damages

When the report is made telephonically, document the name of the person who took the call at the Regulatory Agency (e.g., NRC, LA DNR, or the TRRC), the time the call was made to the Regulatory Agency and the Report Number under which the Regulatory Agency recorded the call.

4.2 Emergency Event Reporting to State and Local Agencies

Please refer to [HSE Document HSE0139-2 – State-Specific Emergency Reporting Procedures](#) for state and local reporting requirements.

4.3. Motor Vehicle Accidents

Always report all property damage accidents, regardless of severity, that involve a third party (i.e., non-Company vehicle, person, animal, mailbox, etc). Refer to the [HSE Handbook](#).

Employees involved in motor vehicle accidents while on Company business, using Company rented or personal vehicles, must report the accident to their immediate supervisor and their HSE representative as soon as possible, regardless of damage severity.

All motor vehicle accidents occurring while on Company business or to Company vehicles, regardless of severity, must always be reported within 24 hours, including:

- Scratches, bumps, and dents
- Damage caused solely by rocks, gravel, or other materials thrown by vehicles and/or damage resulting solely from objects falling on a vehicle or from weather related events
- Damage caused by vandalism or unknown parties

For detailed information regarding the Company-wide HSE policy, vehicle accident reporting and internal benchmarking, refer to the [HSE Handbook](#).

4.4. Injuries/Illnesses

All employee work-related injuries/illnesses will be reported to the immediate supervisor as soon as possible. As applicable, these reports will be transferred to the worker's compensation carrier. This reporting should be done within 24 hours. Refer to the [HSE Policy 0106 – Accident / Injury Investigation and Reporting](#), for further detail.

These types of injuries include, but are not limited to, the following:

- Injuries involving head, neck, shoulders, back, hips or knees, regardless of severity; no exceptions
- Injuries/illnesses requiring a physician's follow-up medical treatment or a prescription medication

All potentially high loss near misses that could have resulted in injuries (including ones requiring first aid), illnesses, or fatalities must be reported to the immediate supervisor and the HSE representative by close of next business day.

Consult the HSE department for additional guidelines regarding environmental release response. Certain environmental releases (e.g., releases into water bodies) must be reported immediately following the event occurrence.

Under the various federal environmental laws - The Clean Air Act, Clean Water Act, CERCLA and SARA, and their state counterparts - a release of a pipeline commodity to the surrounding environment (air, ground, water) may be reportable to a federal and/or state authority if it meets certain reporting criteria. Releases of certain non-pipeline commodities - such as drummed chemicals, caustics, herbicides, etc. - also may be reportable. Contact the Environmental Manager for questions and details on how to handle these releases.

5. Pipeline Regulatory Reporting Requirements

5.1. Accident Reporting (Hazardous Liquids or Carbon Dioxide)

An 'Accident' (as defined in [P0010 – Master Glossary](#)) report is required for each failure in a regulated hazardous liquid or carbon dioxide pipeline system that results in any of the following:

- a) Explosion or fire not intentionally set by the operator.
- b) Release of 5 gallons or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels resulting from a pipeline maintenance activity if the release is:
 - 1) Not otherwise reportable under this section;
 - 2) Not described in 49 CFR 195.52(a)(4);
 - 3) Confined to company property or pipeline right-of-way; and
 - 4) Cleaned up promptly;
- c) Death of any person
- d) Personal injury necessitating hospitalization
- e) Estimated property damage, including cost of clean-up and recovery, value of lost product and damage to the property of the operator or others, or both, exceeding \$50,000.

5.1.1. Immediate Notice of Certain Accidents (Hazardous Liquids or Carbon Dioxide)

Accidents occurring on regulated pipelines shall be reported to the National Response Center at the earliest practicable moment following discovery but no later than one hour after a Confirmed Discovery (as defined in [P0010 – Master Glossary](#)) of any failure that:

- a) Caused a death or personal injury requiring hospitalization;
- b) Resulted in either a fire or explosion not intentionally set by the operator
- c) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding \$50,000;
- d) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water

- or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or
- e) In the judgement of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

Within 48 hours after a Confirmed Discovery the NRC must be contacted again to revise or confirm the initial notice including information such as; an estimate of the amount of product released, an estimate of fatalities and injuries, and all other significant information known. Even when there are no changes to the initial report, the NRC must be contacted to confirm the original information is correct.

A member of the Pipeline Regulatory department shall be responsible for reporting DOT reportable events within one hour of a Confirmed Discovery, if the above criteria is met. Notice shall be made to the National Response Center either by telephone to 800-424-8802 or electronically at <http://www.nrc.uscg.mil> and must include the following information:

- a) Name, address, and identification number of the operator.
- b) Name and telephone number of the reporter.
- c) The location of the failure.
- d) The time of the failure.
- e) The fatalities and personal injuries, if any.
- f) An initial estimate of the amount of product released in accordance with paragraph (c) of this section.
- g) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

When the report is made electronically, the NRC should send the reporting party a confirmation by e-mail within 45 minutes of receiving the online report. If an e-mail confirmation is not received within 45 minutes, the reporting party will call 800-424-8802 to ensure that the NRC has received the report.

5.1.2. 30-Day Accident Report (Hazardous Liquids or Carbon Dioxide)

When a reportable accident is detected (as described in Section 5.1 of this procedure) Form PHMSA F 7000-1 (49 CFR 195.54) must be submitted as soon as practicable but not more than 30 days after the discovery of the accident.

Whenever there are changes in the information reported or additions to the original report filed, a supplemental report shall be filed within 30 days (195.54(b)).

All accidents will be documented using [O&M Form OM-0100-45 – Event/Incident Investigation Summary](#) which will be submitted to the Pipeline Regulatory department.

5.2. Incident Reporting (Natural Gas)

An 'Incident' (as defined in [P0010 – Master Glossary](#)) report is required for each failure in a regulated natural gas pipeline system that results in loss of gas, **and** one or more of the following:

- a) Death of any person;
- b) Personal injury necessitating hospitalization;
- c) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding \$50,000;
- d) Unintentional estimated gas loss of three million cubic feet or more;
- e) An event that is significant in the judgment of the operator, even though it did not meet the above listed criteria.

5.2.1. Immediate Notice of Certain Incidents (Natural Gas)

If an incident occurs on a regulated natural gas pipeline that requires a report submission as described in Section 5.2 of this part, the National Response Center must be notified at the earliest practicable moment following discovery but no later than one hour after a Confirmed Discovery (as defined in [P0010 – Master Glossary](#)) has been made.

Within 48 hours after a Confirmed Discovery the National Response Center must be contacted again to revise or confirm the initial notice including information such as; an estimate of the amount of product released, an estimate of fatalities and injuries, and all other significant information known that are relevant to the cause of the incident or extent of the damages. Even when there are no changes to the initial report, the National Response Center must be contacted to confirm the original information is correct.

A member of the Pipeline Regulatory department shall be responsible for reporting DOT reportable events within one hour of a Confirmed Discovery, if the above criteria is met. Notice shall be made to the National Response Center either by telephone to 800-424-8802 or electronically at <http://www.nrc.uscg.mil> and must include the following information:

- a) Name, telephone number, and identification number of the operator.
- b) Name and telephone number of the reporter.
- c) The location of the incident.
- d) The time of the incident.
- e) The fatalities and personal injuries, if any.
- f) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

When the report is made electronically, the NRC should send the reporting party a confirmation by e-mail within 45 minutes of receiving the online report. If an e-mail confirmation is not received within 45 minutes, the reporting party will call 800-424-8802 to ensure that the NRC has received the report.

5.2.2. 30-Day Accident Report (Natural Gas)

When a reportable incident is detected Form PHMSA F 7100.2 (49 CFR 191.15) must be submitted as soon as practicable but not more than 30 days after the discovery of the accident.

Whenever there are changes in the information reported or additions to the original report filed, a supplemental report shall be filed as soon as practicable with a clear reference by date to the original report (49 CFR 191.15(d)).

All Incidents will be documented using [O&M Form OM-0100-45 – Event/Incident Investigation Summary](#) which will be submitted to the Pipeline Regulatory department.

5.3. Accident/Incident Reporting to State Agencies

Please refer to [Table 1 - Pipeline Regulatory Reporting Guidelines](#) for Federal/State jurisdictional boundaries of interstate and intrastate pipelines and [O&M Procedure 0219 – DOT and State Pipeline Reports](#) for additional Federal and State reporting requirements.

All completed forms will be maintained in the Pipeline Office of Records for the life of the facility.

- **AL** - Alabama Public Service Commission
Accidents/Incidents or undesired events causing damage in the amount of \$5000 or more or undesired events requiring the taking of any segment of a transmission pipeline out of service that occur on Intrastate pipelines regulated by the AL PSC shall be reported by calling (334) 242-5778 weekdays from 8am to 5pm. Verbal notification is required within 1 hour and a copy of the written form PHMSA F 7000-1 and form PHMSA 7100.2 is required within 30 days. After 5pm or on weekends and holidays an AL PSC Gas Pipeline Safety representative can be contacted by calling the phone numbers listed at <http://www.psc.state.al.us/energy/gps/gasreports.htm>.
- **LA** – Company does not operate intrastate pipelines in LA.
- **MS** – Company does not operate intrastate pipelines in MS.
- **MT** – Company does not operate intrastate pipelines in MT.
- **TX** - The Railroad Commission of Texas
Accidents/Incidents occurring on Texas Intrastate pipelines shall be reported to the Railroad Commission of Texas (TRRC) by calling Commission's Emergency line at (512) 463-6788 (512) 463 – 6788 at the earliest

practicable moment but no later than 2 hours and a copy of the written form PHMSA F 7000-1 and form PHMSA 7100.2 is required to be sent within 30 days to safety@rrc.texas.gov.

- **WY** – The Wyoming Public Service Commission
Incidents occurring on Wyoming Intrastate pipelines shall be reported to the Wyoming Public Service Commission Engineering Supervisor by calling (307) 777-7427.

5.4. Accident/Incident Analysis

As soon as practical after a reportable Accident/Incident (as defined in [P0010 – Master Glossary](#)) occurs, the Pipeline Foreman will conduct a review of the Accident/Incident. Denbury may contract a third party expert to determine the root cause of the Accident/Incident. All reportable Accidents/Incidents require investigation.

Other leaks or near misses that, in the opinion of the Pipeline Regulatory Manager, Pipeline Foreman, or Corrosion Foreman, would benefit from root cause analysis may be investigated using this procedure.

An investigation team will be assembled to investigate reportable Accidents/Incidents. The structure of the investigation team should reflect the scope and complexity of the Accidents/Incidents. A typical investigation team could consist of representatives from the following: Pipeline Department, HSE Department, and Legal Department.

An appropriate investigator, normally the Pipeline Foreman, and a third party Accident/Incident investigator, will be dispatched to the scene to investigate the Accidents/Incidents.

The investigators will:

- Interview all employees and other people present immediately following the Accident/Incident.
- Document the findings of these interviews. Documentation must include; whom was interviewed, time, date and all pertinent details pertaining to the Accident/Incident.
- Take representative photographs of the Accident/Incident site and any injuries.
- Secure all involved equipment for further investigation.
- Determine the cause of the Accident/Incident.
- Complete a Root-Cause Analysis of the Accident/Incident in order to determine the best method of preventing the Accident/Incident from re-occurring. Denbury may contract a third party expert to determine the root cause of the Accident/Incident.
- Investigate and list the tasks performed at the time of, and prior to, the Accident/Incident.
- Determine if 'Covered Tasks', as listed in the Denbury "Operator Qualification Program", were being performed during or prior to the Accident/Incident that could have contributed to the Accident/Incident.
- Determine who performed the 'Covered Tasks' that could have contributed to the Accident/Incident. This requirement includes contractor employees.
- Search historical records as needed to determine who performed 'Covered Tasks'.
- If 'Covered Tasks' that could have contributed to the Accident/Incident were performed, inform the OQ Administrator. The OQ Administrator will determine additional steps that should be taken.
- All documentation must be turned in to the Pipeline Regulatory Manager. The documentation should consist of [O&M Form OM0100-45 – Event/Incident Investigation Summary](#) and all time logs from the field personnel involved in the Accident/Incident.
- Document, assign, and track corrective actions to completion.

A summary of the analysis findings is communicated to Denbury employees with responsibilities affected by corrective action as well as their supervisors.

5.5. Excavation Caused Damage (Texas)

Each reporting location must report excavation-caused damage to all Texas pipelines within 30 working days of the event or of the operator's actual knowledge of the damage.

The Pipeline Regulatory Manager or designee shall report the damage to the Railroad Commission of Texas using the Texas Damage Reporting Form (TDRF) (<http://webapps.rrc.state.tx.us/TPD/publicHomeAction.do>),

5.6. Visual Inspection of Pipe Failures

After a release from defective pipe, obtain and visually inspect a sample of failed pipe whenever a pipe failure requires that the defective section be removed and replaced. This includes a longitudinal weld seam failure. Perform the inspection using the procedures that follow, and record the inspection results on [Form OM-0200-02 – Pipeline Evaluation Report](#).

Note: The failed pipe must be identified, marked, and retained for six months or the period specifically requested by the Manager – Pipelines, whichever is longer. When unable to determine the cause of the failure or the extent of the defect using visual inspection, submit the specimen for laboratory analysis.

5.7. Accident/Incident Response Review

[Section 5.4 - Accident/Incident Analysis](#) explains how an accident shall be investigated and reviewed. The review is documented on [O&M Form OM0100-45 – Event/Incident Investigation Summary](#).

5.8. Post-Accident/Incident Drug Testing Review

Per 49 CFR Part 199.105 (b)(2), 199.117(a)(5), and 199.119(a)(b), PHMSA regulations require post-accident drug testing of each surviving covered employee or contract employee whose performance either contributed to a jurisdictional reportable pipeline Accident/Incident or cannot be completely discounted as a contributing factor. Testing must be completed as soon as possible but no later than 32 hours after the Accident/Incident. The Post Accident Drug Testing Review, included in [O&M Form OM0100-45 – Event/Incident Investigation Summary](#), shall be used to document the review of employees considered for testing. If a test is not administered for any reason, documentation must be completed in accordance with the [Anti-Drug and Alcohol Misuse Prevention Plan](#) stating why the test was not promptly administered and the reasons for not administering the test. Documentation is to be retained in accordance with [O&M Procedure 1400 – Records Retention by O&M Procedure](#). The Operations Manager – CO₂ Supply and Pipelines will determine, with the input of the Pipeline Superintendent, Regulatory Manager and other site personnel to determine which pipeline employees and contract employees require drug testing. In accordance with the [Anti-Drug and Alcohol Misuse Prevention Plan](#) reporting of drug testing results are required.

The procedures for conducting such post- Accident/Incident drug testing are outlined in the Denbury [Anti-Drug and Alcohol Misuse Prevention Plan](#). Contractors performing covered functions on Denbury pipeline facilities are required to have a written anti-drug and alcohol misuse plan conforming to the DOT requirements and procedures set forth in 49 CFR part 199 and 49 CFR part 40. The Operations Manager – CO₂ Supply and Pipelines will determine, with the input of the Pipeline Superintendent, Regulatory Manager and other site personnel to determine which pipeline employees and contract employees require drug testing.

5.9. Post-Accident Alcohol Testing Review

Per 49 CFR 199.225(a)(1), 199.227(b)(4), and 199.229(a)(c), PHMSA regulations require post-accident alcohol testing of each surviving covered employee or contract employee whose performance either contributed to a jurisdictional reportable pipeline Accident/Incident or cannot be completely discounted as a contributing factor. Testing must be completed as soon as possible but no later than 2 hours after the Accident/Incident. The Post-Accident Alcohol Testing Review, included in [O&M Form OM0100-45 – Event/Incident Investigation Summary](#), shall be used to document the review of employees considered for testing. If a test is not administered for any reason, documentation must be completed in accordance with the [Anti-Drug and Alcohol Misuse Prevention Plan](#) stating why the test was not promptly administered and the reasons for not administering the test. Documentation is to be retained in accordance with [O&M Procedure 1400 – Records Retention by O&M Procedure](#). The Operations Manager – CO₂ Supply and Pipelines will determine, with the input of the Pipeline Superintendent, Regulatory Manager and other site personnel to determine which pipeline employees and contract employees require alcohol testing. In accordance with the [Anti-Drug and Alcohol Misuse Prevention Plan](#) reporting of alcohol testing results are required.

The procedures for conducting such post- Accident/Incident drug and alcohol testing are outlined in the Denbury [Anti-Drug and Alcohol Misuse Prevention Plan](#). Contractors performing covered functions on Denbury pipeline facilities are required to have a written anti-drug and alcohol misuse plan conforming to the DOT requirements and procedures set forth in 49 CFR part 199 and 49 CFR part 40. The Operations Manager – CO₂ Supply and Pipelines will determine, with the input of the Pipeline Superintendent, Regulatory Manager and other site personnel to determine which pipeline employees and contract employees require alcohol testing.

5.10. Post-Accident Operator Qualification Review

Information must be gathered to determine if Covered Tasks were performed during or prior to a pipeline Accident/Incident in conformance with the Denbury Operator Qualification Program. The minimum requirement is to create a list of tasks and who was performing them. This includes contractor employees and Denbury employees. Depending on the type of Accident/Incident, a search of historical records may be required.

Per 49 CFR Part 195.505 (d), the accident investigators will:

- Investigate and list the tasks performed at the time of the Accident/Incident and just prior to the Accident/Incident.
- Determine if 'Covered Tasks' as listed in the Denbury [Operator Qualification Program](#) were being performed or performed just prior to the Accident/Incident that could have contributed to the Accident/Incident.
- Determine who performed the 'Covered Tasks' that could have contributed to the Accident/Incident. This requirement includes contractor employees.
- Search historical records as needed to determine who performed 'Covered Tasks.'
- If 'Covered Tasks' that could have contributed to Accident/Incident were performed, inform the OQ Administrator. The OQ Administrator will determine additional steps that should be taken.

5.11. Hazard and Accident/Incident Reoccurrence Minimization

The Company will make every effort to reduce the likelihood of hazards and Accidents/Incidents identified in the preceding section of this manual from reoccurring. As detailed in [Section 6 – Investigation](#), a root cause analysis may be conducted after an Accident/Incident in order to identify the cause and contributing factors associated with the Accident/Incident.

All hazards identified as root causes or contributing factors will be addressed by the Pipeline Foreman and other Denbury Representatives as required in order to minimize the likelihood of the Accident/Incident occurring again. Types of minimization methods may include:

- Safety meetings designed to specifically address the hazard identified
- Focused training courses designed to familiarize the personnel with the specific measures necessary to reduce the effects of the potential hazard
- Mechanical and/or physical controls designed to limit access to hazard areas or reduce the impacts of Accident/Incident
- Posting of warning signs in high hazard areas
- Additional emphasis and training on damage prevention
- Additional efforts with public officials or emergency responders
- All documentation on the root-cause analysis, whether internal or a Third-Party investigator will be maintained in the Pipeline Office of Records

6. Investigation

The Company will investigate all undesired events that result in, or could have resulted in, a fatality, injury or illness, major property damage, process/product loss, or harm to the environment. Upon the advice of the legal department, such investigation may be conducted at the direction of the legal department or outside lawyers and pursuant to the attorney-client privilege and/or work product or other legal protection. If DOT should investigate an accident/incident, Denbury will provide assistance as reasonable. The investigative process includes identifying root causes or causal factors that contributed to the occurrence, determining the necessary corrective actions, and timely follow-up to ensure that corrective actions have been completed.

While lessons learned from conducting investigations may be shared with Company employees, all staff should hold specific, sensitive information (e.g. names of persons involved, specific locations, financial data, etc.) in strict confidence. The primary purpose of an investigation is not to find fault or place blame. Reports resulting from investigations may be discoverable by government investigators or third parties.

If, in the course of an investigation, evidence suggests the possibility that the occurrence was not an accident but an intentional violation of Company policy or procedures, negligence or illegal activity, such evidence will be immediately turned over to the appropriate Company officials or authorities.

During the investigation, determine immediate and basic (root) causes and remedial actions using Company-approved investigation methodology. Document findings via [O&M Form OM0100-45 – Event/Incident Investigation Summary](#).

When an undesired event is reported to the DCC, the extent of the investigation and who will conduct the investigation will be determined during an emergency response conference call. PSM/RMP facilities' participants must include:

- At least one employee knowledgeable in the process involved
- Contract employee if the event involved contractor's work
- Other persons with appropriate knowledge and experience to properly investigate and analyze the event, if necessary

Depending on the extent of the event and investigation, the investigative team will:

- Gather all available event details
- Sketch the scene and/or take pictures when possible
- Collect and save physical evidence and pertinent data
 - If specimens are cleaned, use water only
 - Do not use a wire brush or oil
 - Do not fit parts back together during packaging for shipping
 - Carefully mark the direction of gas flow and pipe's orientation to 12 o'clock on specimens
- For significant events, evidence should be maintained in the location and position where found until the investigation is completed
- Interview witnesses and responsible parties, regarding the events leading up to and during the occurrence
- Address questions regarding machinery, personal protective equipment, tools and equipment, chemicals and environmental concerns, and process safety
- Review written procedures, job instructions, and specifications covering the operation being performed at the time of the event
- Review the attitudes, priorities, stress levels, physical condition, and perceptions of involved employees, including Control Center employees on duty at the time of the Incident
- Consult with the Legal Department before beginning the investigation to determine if it is advisable to have attorneys involved and to protect the investigation as privileged.

After collecting applicable information, the investigation team will prepare and write a report that accomplishes all of the following:

- Interprets the event details
- Identifies contributing factors/immediate cause(s)
- Determines the possible root cause(s)
- Develops recommended corrective actions for each cause or contributing factor
- Develops final recommendations that should consider risk and economic analysis
- Establishes individual responsibilities for and completion dates for each recommendation

- Provides a mechanism that tracks each recommendation to completion

HSE and the Regulatory Group will critique all emergency responses, as warranted. The critique should determine whether emergency procedures were followed and effective, and whether emergency response protocol procedures and/or response changes are necessary. Submit any changes to the ADC in conformance with [O&M Procedure 0001 – Standards Modification](#).

7. Training

Provide the information in this procedure to all employees during regularly scheduled safety training sessions:

- Upon policy implementation
- Whenever there is a change
- Once every three years thereafter

8. Documentation

Report all undesired events as specified in [Section 3](#). Additionally, use the applicable O&M forms or electronic systems to document the event. Attach supporting documentation to reporting forms where applicable. Use [O&M Form OM0100-45 – Event/Incident Investigation Summary](#), basic cause analysis model, or such other format as directed by the Legal Department for all investigations

Area/Region HSE and Pipeline Regulatory representative will track the reporting process completion, determine if events are recordable, preventable, etc. and close, distribute, and file reports as necessary.

The HSE Department documents and tracks remedial actions and distributes reports, including 'lessons learned', to other departments as needed and/or required.

Do not destroy documents before consulting the Legal department.

Completed Investigation/Review Forms shall be retained for the life of the facility.

9. References

- 18 CFR Part 260.9 (d)
- 29 CFR Part 1910.119
- 49 CFR Part 191.3, .5, .7, .15, .23, .25
- 49 CFR Part 192.605 (d) (e), .615 (a) (b), .617
- 49 CFR 195.54
- 49 CFR Part 195.402 (c) (2)
- 49 CFR Part 195.402 (c) (5)
- 49 CFR Part 195.402 (c) (6)
- 49 CFR Part 195.402 (e) (9)
- 49 CFR Part 195.505 (d)
- 49 CFR Part 199.105 (b)
- 49 CFR Part 199.225 (a)
- [Anti-Drug and Alcohol Misuse Prevention Plan](#)
- [APSC Rules and Regulations for Gas Pipeline Safety, Appendix A](#)
- [HSE Guidelines for Contractors](#)
- [HSE Handbook](#)
- [HSE Policy 0106 – Accident / Injury Investigation and Reporting](#)
- [HSE Policy 0139 - Emergency Response Guidelines](#)
- Louisiana Administrative Code Title 43 Part XIII
- [O&M Procedure 0213 – Leaks, Pipe and Weld Defects, Repairs](#)
- [O&M Procedure 0219 – DOT and State Pipeline Reports](#)
- [O&M Procedure 1900 – Emergency Response](#)
- [O&M Form OM0100-45 – Event/Incident Investigation Summary](#)
- [Operator Qualification Program](#)
- [P0010 – Master Glossary](#)
- Site-Specific Emergency Manual
- Texas Regulations Title 16 TAC 18.11
- [Emergency Response Plans](#)

Attachment 1 – Event Classification

Receiving Notices of Events: 49 CFR 192.615 (a)(1); 49 CFR 195.402(e)(1)

In the event of a release of gas or carbon dioxide from a pipeline, notices of the release would be expected to be received in one or more of the following ways:

- Abnormal loss of pressure or other pressure noted by the controllers at the Denbury Control Center monitoring the pipeline SCADA system
- Verbal notification by a company representative or contractor conducting routine maintenance on pipeline systems
- Verbal notification by a company representative or contractor conducting aerial over flights of the pipeline right-of-ways
- Verbal notifications by private citizens or government agencies observing a release
- Verbal notifications by representative of product sales customers, at one of the pipeline sales points, of a release located in the vicinity of the sales point or due to a noted reduction in sales pressure

When receiving telephonic notification of events, the Denbury Control Center (DCC) will, at a minimum, obtain the following information:

- Name and call back number for the individual or group calling. If a Denbury employee reports the leak, the DCC Controller asks if they are in the Production Department or the Pipeline Department.
- Are there any observed injuries or property damages?
- Description of the release including pertinent data concerning:
 - Size Of Vapor Cloud
 - Characterize Any Smell (Musty? Rotten Egg Smell?)
 - Velocity
 - Noise
 - Presence Of Flying Debris
 - Wind Direction
- Location of nearby residences
- Location of the release

Following notification, the Denbury Control Center will identify the area and immediately contact the Pipeline Foreman responsible for the identified area. The area of responsibility for each Foreman is identified on the Pipeline Map provided to the Denbury Control Center. In the event that the Pipeline Foreman cannot be contacted, the Denbury Control Center shall contact the Pipeline Superintendent. The Denbury Control Center shall also transmit the information above to the Pipeline Regulatory Manager.

Identifying Events:

The location and nature of an event will be determined using the following methods:

- Review of the system information available from the pipeline SCADA system available monitoring equipment located at the Denbury Control Center
- Use of available mapping and schematics to identify the most likely location and cause of any reported event
- Utilization of the operator knowledge of the systems including but not limited to knowledge of any previous releases in a given area
- When necessary and safe to do so, immediate visual inspection of the impacted area by properly trained company personnel or appropriate trained contractors

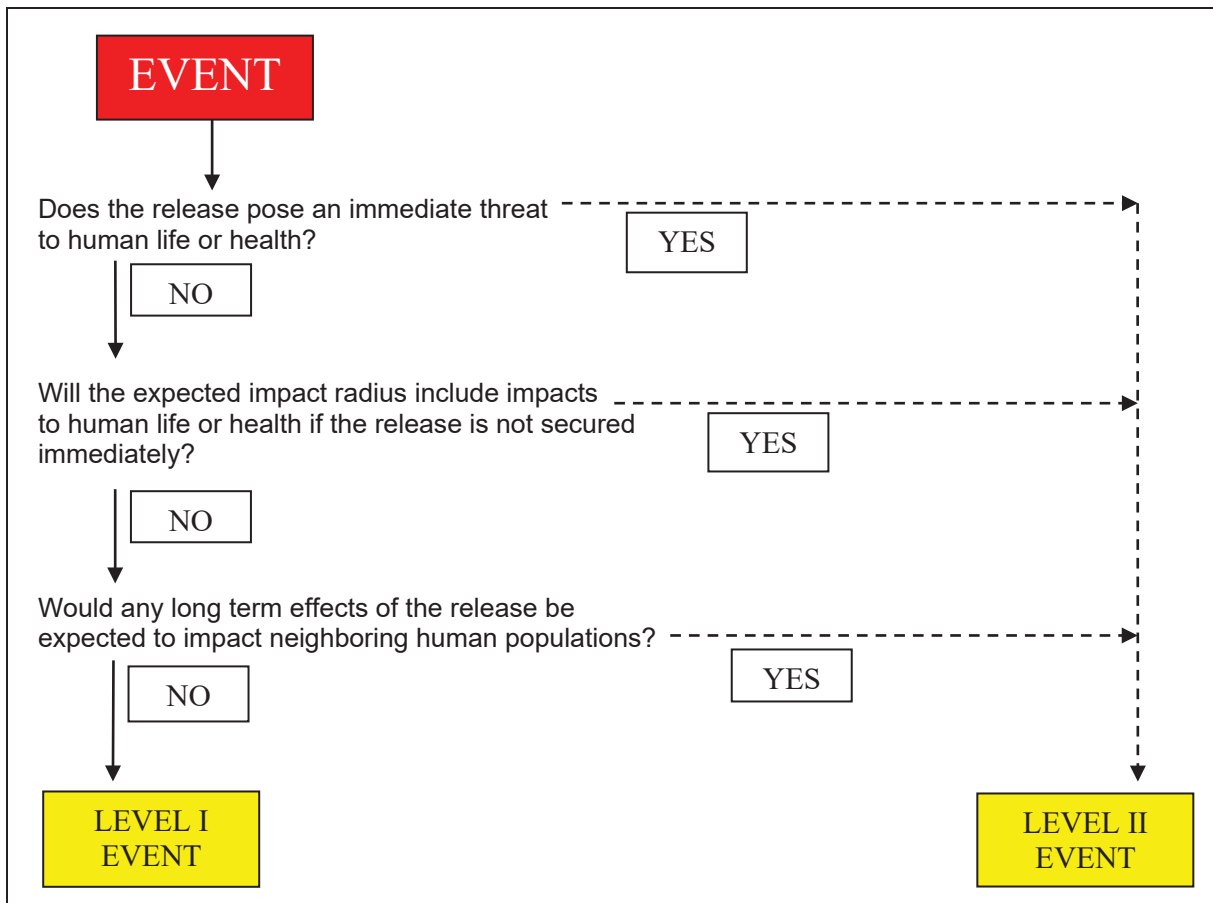
Classifying Events:

Events occurring in the vicinity of this pipeline will be classified into one of (2) categories by the Pipeline Foreman or the first available Pipeliner at the time of the Incident.

- Level I Events shall include pipeline damage, leaks, fires, or other types of releases that **DO NOT** pose any immediate threat to human life or health.
- Level II Events shall include pipeline damage, leaks, fires, or other types of releases that **DO** pose an immediate threat to human life or health.

A flow chart for suggested methods of determining the appropriate level of threat during a given release is given in this section. Procedures for responding to an event of either category mentioned above are given below:

Event Classification Flowchart



Prompt and Effective Response (49 CFR 192.615 (a)(3); 49 CFR 195.402(e)(2))

The following procedures are to be used during an event near or involving the pipeline covered by this plan. These procedures are not designed to be all inclusive of the necessary actions during any specific events; however, they should be used as a general guide during any event.

LEVEL I Event

- A) Fire or Explosion - CO₂ is non-flammable, non-explosive, and the essential hazard lies in the fact that it is heavier than air and it is a potential asphyxiant in low lying areas.
- B) Review the information from the SCADA system, pipeline diagrams, and mapping to identify the logical points along the pipeline to isolate the affected area and decrease or terminate the flow of CO₂ or gas.

- C) Shut down or close any appropriate valves or pumping systems to decrease or terminate the flow of CO₂ or gas.
- D) Notify the Qualified Individual to make notifications to all appropriate agencies with jurisdiction over the pipeline.
- E) Log all events in an ongoing documentation log.
- F) Dispatch appropriate personnel with detection equipment and proper personal protective equipment to the site to repair the pipeline and extinguish any fires as necessary.
- G) Generate and file all appropriate written regulatory reports.

Accidental Release

- A) Review the information from the SCADA system, pipeline diagrams, and mapping to identify the logical points along the pipeline to isolate the affected area and decrease or terminate the flow of CO₂ or gas.
- B) Shut down or close any appropriate valves or pumping systems to decrease or terminate the flow of CO₂ or gas.
- C) Notify the Qualified Individual to make notifications to all appropriate agencies with jurisdiction over the pipeline.
- D) Log all events in an ongoing documentation log.
- E) Dispatch appropriate personnel with detection equipment and proper personal protective equipment to the site to repair the pipeline.
- F) Generate and file all appropriate written regulatory reports.
- G) Operational Failure Causing a Hazardous Condition; **Examples:** Actuation of a pressure relief valve, over pressuring of the pipeline due to the apparent failure of an overpressure safety device.
- H) Review the information from the SCADA system, pipeline diagrams, and mapping to identify the logical points along the pipeline to isolate the affected area and decrease or terminate the flow of CO₂ or gas.
- I) Shut down or close any appropriate valves or pumping systems to decrease or terminate the flow of CO₂ or gas.
- J) Notify the Qualified Individual to make notifications to all appropriate agencies with jurisdiction over the pipeline.
- K) Log all events in an ongoing documentation log.
- L) Complete investigation to determine the cause of the operational failure and to determine the appropriate corrective action to prevent reoccurrence.
- M) Dispatch appropriate personnel with detection equipment and proper personal protective equipment to the site to repair the pipeline.
- N) Generate and file all appropriate written regulatory reports.

Natural Disaster

- A) Continual monitoring of weather and news-related sources by controllers to determine if any pending situation may have an adverse effect on pipeline operations.
- B) Review the information from the SCADA system, pipeline diagrams, and mapping to identify the logical points along the pipeline to isolate the affected area and decrease or terminate the flow CO₂ or gas.
- C) Consider shut down or closure of any appropriate valves or pumping systems to decrease or terminate the flow of CO₂ or gas.
- D) Dispatch appropriate personnel to evaluate conditions of exposed portions of the pipeline.
- E) Log all events to obtain appropriate documentation.

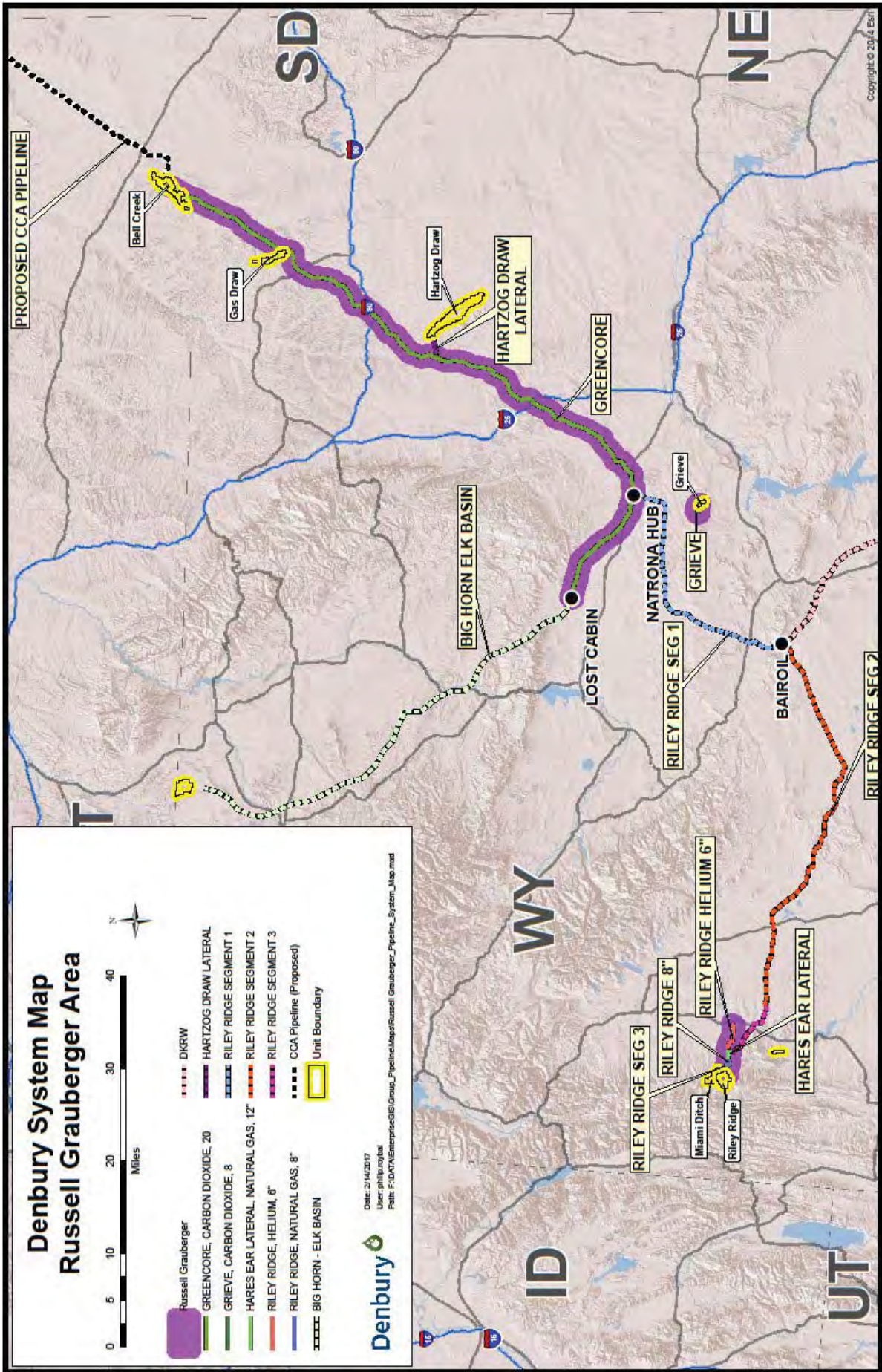
Attachment 3 – Initial Emergency Conference Call Checklist

The following information will be discussed on the call; however, the call SHOULD NOT BE DELAYED to collect the information

- **Discovery Date and Time**
- **Location** (enough information to identify the site)
 - State
 - County
 - Address or nearest town
 - Description (Station, Index)
 - Nearest Crossroads
 - Latitude & Longitude
 - Pipeline Type (Transmission or Gathering)
 - Class Location
 - Located in HCA
- **Liquids/Gas Released**
 - CO₂ Lost (Gal) or Gas Lost (MCF)
 - Environmental Reporting (State or Federal)
 - Operating Pressure (psig)
 - Leak/Relief Diameter (inches)
 - Venting Time
 - For Blowdowns: pipe length, pipe diameter
 - Sheen on any water body
 - Water body name
 - Actions taken to stop/clean release
- **Bodily Injury/Illness**
 - Number of Injured
 - Nature of Injuries
 - Name(s) of Injured
 - Job Title(s) of Injured
 - Death/Inpatient Hospitalization Required
 - Family Notified
- **Property Damage/Repairs:** estimated costs, not including gas released
- **Service Interrupted/Customer Impact**
- **Waiver/Special Permit Requirements**
- **Roads Closed**
- **Public Evacuation**
- **Media Involvement**
- **Local/State/Federal Involvement**
- **Control Center Actions or Fatigue**
- **Drug/Alcohol Testing Required**
- **OQ Verification Required**
- **Local Company Contact**, when event is reportable to a regulatory agency

Table 1 – Pipeline Jurisdiction Table

Regulatory Agency	Intrastate Gas Transmission	Intrastate Hazardous Liquids	Interstate Gas Transmission and Hazardous Liquids
<u>Alabama Public Service Commission</u>	AL	AL	PHMSA
<u>Louisiana Department of Natural Resources</u>	LA	LA	PHMSA
<u>Mississippi Public Service Commission</u>	MS	PHMSA	PHMSA
<u>Montana Public Service Commission</u>	MT	PHMSA	PHMSA
<u>Railroad Commission of Texas</u>	TX	TX	PHMSA
<u>Wyoming Public Service Commission</u>	WY	PHMSA	PHMSA



Lost Cabin CO2 Plant - Description of Facilities

Greencore Compressor Station

Greencore Compression Station is owned and operated by Greencore Pipeline Company LLC. The station is located adjacent to the Lost Cabin Gas Plant operated by Conoco Phillips in Fremont County, Wyoming at GPS coordinates N43.283691 and W107.602539.

Greencore Compressor Station is designed to compress up to 60 MMscfd of CO₂ by receiving two separate streams from the Lost Cabin Gas Plant, a 1-psig stream at a rate of up to 22 MMscfd and a 40-psig stream at a rate of up to 38 MMscfd. The 1-psig stream will be compressed by three (3) Enerflex screw type compressors and combined with the 40-psig stream where it will be delivered to the (3) American Warrior reciprocating compressors for compression to pipeline pressure. The discharge CO₂ will be cooled via aerial coolers and delivered to an on-site meter station for measurement and disposition at a maximum pressure of 2,200 psig (normal operating pressure will be 1,700 psig).

Compressors

3 Low Pressure Compressors – Rotary screw type compressors driven by 1000HP electric motors 1800 RPM induction.

3 High Pressure Compressors – Reciprocating type compressors four stages driven by 4650 HP electric motors 720 RPM synchronous.

Aerial Coolers

3 Low Pressure Compressor lube oil coolers/discharge coolers

3 High Pressure Compressor interstage coolers

1 High Pressure Compressor discharge cooler

Scrubbers/Vessels

1 Low Pressure Compressor inlet suction scrubber

1 Low Pressure Compressor discharge scrubber

1 High Pressure Compressor inlet suction scrubber

Pumps

1 Low Pressure Compressor suction scrubber pump

1 vent scrubber pump

1 truck loading pump

1 sump pump

Tanks/Sumps

1 Low Pressure Compressor lube oil tank

2 High Pressure compressor lube oil tank

1 slop oil tank

1 Drain sump double wall

Miscellaneous Equipment

2 instrument air compressor packages

1 instrument air dryer package

1 vent stack

Electrical Equipment, Instrumentation and Measurement

5KV Switchgear

5KV MCC

480V MCC

VFD's and/or motor starters for Compressors

Transmitters

RTD's

Buildings

Compressor Building

Motor Control Center

Control Room/Office

Warehouse Building

Valves

Control Valves and other actuated valves

Relief Valves/PSV's

Greencore CO2 Pipeline - Description of Facilities

MLV-1 Lost Cabin Gas Plant

MLV-1 located at the Lost Cabin Gas Plant is the originating point of the 20-inch Greencore Pipeline. This valve is located in Fremont County, Wyoming at GPS coordinates 43.2831 and 107.6003. This is located at MP 00. This is a remote control valve.

The meter station consist of one 8" Daniel Senior Orifice Meter SCADA Pak 32, Meter 7300. There are no automatic shutdowns in the valve station but the DCC has software high pressure alarms set approximately 50 psig above the normal operating pressure. MOP of the station is 2220 psig.

Three-phase 460/277 volt, 60 hertz, wye configuration power is supplied to the meter station directly from Lost Cabin Compressor Station which is supplied by High Plains Electric Company. Low voltage single-phase power (120/240V) is transformed from a transformer. A battery charger and batteries are located at the meter station to provide backup power during a utility failure for control, instrumentation and the PLC. The batteries have a maximum of 5 days capacity at full load. An inverter is installed to power the satellite equipment.

MLV-2

MLV-2 is located in Natrona County, Wyoming at GPS coordinates 43.16858 and 107.2684. This is located at MP 19.8. This is a motor operated valve.

Power to this valve site is provided by High Plains Power as 240 single-phase. There is no battery backup. This is a stand-alone rack powered site with no building and no communication.

MLV-3

MLV-3 is located in Natrona County, Wyoming at GPS coordinates 43.04556 and 107.0828. This is located at MP 32.8 and is a motor operated valve.

MLV- 3 receives single phase 240 volt AC power from High Plains Electric Company.

A battery charger and batteries are located at the meter station to provide backup power during a utility failure for control, instrumentation and the PLC. The batteries have a maximum of 5 days capacity at full load. An

inverter is installed to power the satellite equipment. Communications have been disabled at this site as of 4/17/14.

MLV-4 Natrona Hub

MLV-4 is located at the Natrona Hub in Natrona County, Wyoming at GPS coordinates 43.02574 and 106.9787. This is located at MP 39.6. This is a remote control valve. Future pump station is planned at this location.

MLV- 4 receives single phase 240 volt AC power from High Plains Electric Company.

A battery charger and batteries are located at the meter station to provide backup power during a utility failure for control, instrumentation and the PLC. The batteries have a maximum of 5 days capacity at full load. An inverter is installed to power the satellite equipment.

MLV-5

MLV-5 is located in Natrona County, Wyoming at GPS coordinates 43.2186 and 106.50544. This is located at MP 45.1. This is a motor operated valve.

Power to this valve site is supplied by High Plains Power as 240V single phase. There is no battery backup. This is a stand-alone rack powered unit with no building and no communication.

MLV-6

MLV-6 is located in Natrona County, Wyoming at GPS coordinates 43.21198 and 106.59529. This is located at MP 64.7. This is a motor operated valve.

This is a motor operated valve. Power to this valve site is generated by a solar panel. There is limited battery backup on the solar panel. The accumulator storage is 2 strokes (open to close = 1 stroke). This is a stand-alone site with no building and no communication. Batteries at full charge up to 4 strokes

MLV-7

MLV-7 is located in Natrona County, Wyoming at GPS coordinates 43.43888 and 106.446. This located at MP 83.1. This is a remote control valve.

MLV- 7 receives single phase 240 volt AC power from Rocky Mountain Power. There is an electrical building on location that houses PLC

MLV-8

MLV-8 is located in Natrona County, Wyoming at GPS coordinates 43.48549 and 106.4052. This is located at MP 87.2. This is a remote control valve. Launcher and Receiver are located at this site.

This is a solar powered site with a control building. A battery charger and batteries are part of the solar array power system located at the meter station. The batteries have a maximum of 5 days capacity at full load. An inverter is installed to power the satellite equipment. This site has a self-contained solar powered automated valve. The accumulator storage is 6 strokes (open to close = 1 stroke). Communications have been disabled at this site as of 4/17/14.

MLV-9

MLV-9 is located in Johnson County, Wyoming at GPS coordinates 43.60539 and 106.2795. This is located at MP 100.5. This is a motor operated valve.

Power to this valve site is supplied by Rocky Mountain Power as 240V single phase. There is no battery backup as this is a stand-alone rack mounted site with no building and no communication.

Hartzog Interconnect

Hartzog interconnect is located in Johnson County, Wyoming at GPS coordinates 43.827805 and -106.168375. This is located at MP 117.5. This is a manual valve. Location consists of 12'' riser with 8'' block valve and 2'' jumper.

MLV-10

MLV-10 is located in Johnson County, Wyoming at GPS coordinates 43.8337 and 106.1709. This is located at MP 117.6. This is a remote control valve.

Power to this valve site is generated by a solar array / battery system. There is a battery backup on the solar panel with a maximum of 5 days capacity at full load. There is an inverter for the communications. The accumulator storage is 2 strokes (open to close = 1 stroke). Communications have been disabled at this site as of 4/17/2014

MLV-11

MLV-11 is located in Johnson County, Wyoming at GPS coordinates 44.07988 and 106.04505. This is located at MP 138. This is a motor operated valve. MLV-11 receives single phase 120/240 volt AC power from Powder River Energy. There is no battery backup as this is a stand-alone rack mounted site with no building and no communication.

Midpoint Pump Station

The midpoint station is located in Campbell County, Wyoming at GPS coordinates 44.12958 and 105.98896. This is located at MP 144. There is a launcher and receiver at this location. A future pump station is planned at this location.

The Midpoint Pump Station receives single phase 120/240 volt AC power from Powder River Energy. This is a stand-alone rack with no battery backup.

MLV-12

MLV-12 is located in Campbell County, Wyoming at GPS coordinates 44.17615 and 105.9104. This is located at MP 148. This is a motor operated valve.

MLV-12 receives single phase 120/240 volt AC power from Powder River Energy. There is an electrical building on location that houses PLC

MLV-13

MLV-13 is located in Campbell County, Wyoming at GPS coordinates 44.18255 and 105.90473. This is located at MP 149. This is a remote control valve.

MLV-13 receives single phase 120/240 volt AC power from Powder River Energy. A battery charger and batteries are located at the valve station to provide backup power during a utility failure for control, instrumentation and the PLC. The batteries have a maximum of 5 days capacity at full load. An inverter is installed to power the satellite equipment.

MLV-14

MLV-14 is located in Campbell County, Wyoming at GPS coordinates 44.28564 and 105.81169. This is located at MP 158. This is a motor operated valve.

MLV-14 receives single phase 120/240 volt AC power from Powder River Energy. There is no battery backup. This is a stand-alone site with no building and no communication.

MLV-15

MLV-15 is located in Campbell County, Wyoming at GPS coordinates 44.50740 and 105.63146. This is located at MP 178. This is a remote control valve.

MLV-15 receives single phase 120/240 volt AC power from Powder River Energy. A battery charger and batteries are located at the meter station to provide backup power during a utility failure for control, instrumentation and the PLC. The batteries have a maximum of 5 days capacity at full load. An inverter is installed to power the satellite equipment. Location has pneumatic 4" control valve. An air supply system is located inside electrical building.

MLV-16

MLV-16 is located in Campbell County, Wyoming at GPS coordinates 44.51391 and 105.62888. This is located at MP 179. This is a motor operated valve.

Power to this valve site is generated by a solar panel. There is limited battery back up on the solar panel. The accumulator storage is 2 strokes (open to close = 1 stroke). This is a stand-alone site with no building and no communication. Batteries at full charge up to 4 strokes.

MLV-17

MLV-17 is located in Campbell County, Wyoming at GPS coordinates 44.73457 and 105.38962. This is located at MP 200. This is a motor operated valve. Launcher and Receiver are located at this site.

MLV-17 receives single phase 120/240 volt AC power from Powder River Energy. There is no battery backup as this is a stand-alone rack mounted site with no building and no communication.

MLV-18

MLV-18 is located in Campbell County, Wyoming at GPS coordinates 44.79552 and 105.31344. This is located at MP 206. This is a remote control valve.

Power to this valve site is generated by a solar array / battery system. There is a battery pack up on the solar panel with a maximum of 5 days capacity at full load. There is an inverter for the communications. The accumulator storage is 2 strokes (open to close = 1 stroke).

MLV-19

MLV-19 is located in Campbell County, Wyoming at GPS coordinates 44.94426 and 105.21804. This is located at MP 218. This is a motor operated valve.

MLV-19 receives single phase 120/240 volt AC power from Powder River Energy. There is no battery backup as this is a stand-alone rack mounted site with no building and no communication.

MLV-20 Bell Creek Delivery Facility

MLV-20 is located at the Bell Creek Delivery Facility in Powder River County, Montana at GPS coordinates 45.107988 and 105.094009. This is located at MP 231. This is a motor operated valve.

The meter station consist of one 8" Daniel Senior Orifice Meter SCADA Pak 32, Meter 7300. There are no automatic shutdowns in the valve station but the DCC has software high pressure alarms set approximately 50 psig above the normal operating pressure. MOP of the station is 2220 psig.

MLV-20 receives single phase 120/240 volt AC power from Black Hills power. A battery charger and batteries are located at the meter station to provide backup power during a utility failure for control, instrumentation and the PLC. The batteries have a maximum of 5 days capacity at full load. An inverter is installed to power the satellite equipment.

Site C CO2 Interconnect – Description of Facilities

Denbury Owned Fleur De Lis (FDL) Operated

The Site C Meter station, E-house and generator building are located in Natrona County, Wyoming at GPS coordinates 43.033748 and -106.866828. This is located at MP 45.

Denbury is responsible for the maintenance of the 8” piping located downstream of the meter station. FDL operates the meter station. The meter station consists of one 8” Daniels Senior Orifice Meter (meter 7350) and a SCADA Pak 32 flow computer and PLC located in the E-house. Denbury is responsible for the SCADA Pak 32 flow computer and our satellite system, and the backup generator. FDL is responsible for their flow computer, H2S analyzer, H2O analyzer, UPS system, PLC located in the E-house, their satellite system, and one automated ESD valve. There are no Denbury operated automatic shutdowns in the valve station however the DCC has software high pressure alarms set approximately 50 psig above the normal operating pressure. This valve is monitored by DCC but can only be remotely shutdown by FDL’s Control Center. MOP of the meter station is 2220 psig.

The Site C Meter station receives single phase 240 volt AC power from High Plains Power. There is an uninterrupted power supply (UPS), and battery charger and batteries. The batteries have a maximum 5 days capacity at full load. These will provide backup power during a utility failure for control, instrumentation and PLC programs in the event there is also a generator malfunction. An inverter is installed to power the satellite equipment. There is a 60KW propane fueled generator owned by Denbury as a backup power supply to the station.

Generator

The Generator is located inside of the generator building in Natrona County, Wyoming at GPS coordinates 43.033638 and -106.866556. There is a 60KW propane fueled generator that will supply 240 volt single phase AC power through an automatic transfer switch to the site in the event of utility power loss.

Grieve CO2 Pipeline - Description of Facilities

Fleur De Lis (FDL) Meter Station

The FDL Meter station is located in Natrona County, Wyoming at GPS coordinates 42.72599 and -107.06793. This is located at MP 0.00. Motor operated valve #MOV 7400 is located at this meter station.

Denbury is responsible for the maintenance of the 8” piping located upstream of the meter station to the FDL valve. FDL owns and operates the meter station. The meter station consists of one 6” Canalta Orifice meter (meter 7400) and a SCADA Pak 32 flow computer. Denbury is responsible for a SCADA Pak 32 flow computer, a H2S analyzer, H2O analyzer, UPS system, PLC, satellite system, one automated ESD valve and the backup generator. All other equipment in the building belongs to FDL. There are no Denbury operated automatic shutdowns in the valve station however the DCC has software high pressure alarms set approximately 50 psig above the normal operating pressure. This valve can also be shut in by the DCC due to out of contract quality. MOP of the meter station is 2440 psig.

The FDL Meter station receives single phase 240 volt AC power from High Plains Power. There is an uninterrupted power supply (UPS) that will provide backup power during a utility failure for control, instrumentation and PLC programs to Denbury owned equipment only. There is a 35KVA propane fueled generator owned by Denbury as a backup power supply to the station “Essential Load Center”. The UPS is also used to power the satellite equipment.

Generator

The Generator is located outside of FDL’s Meter station building in Natrona County, Wyoming at GPS coordinates 42.73597 and -107.06840. There is a 35KW propane fueled generator that will supply 240 volt single phase AC power through an automatic transfer switch to the site in the event of utility power loss.

Launcher Facility

The launcher facility is located in Natrona County, Wyoming at GPS coordinates 42.73607 and -107.06799. This is located at MP 0.0.

Receiver Facility

The Receiver Facility is located in Natrona County, Wyoming at GPS coordinates 42.73384 and -107.00943. This is located at MP 3.46.

Riley Ridge Natural Gas Pipeline - Description of Facilities

Riley Ridge Inlet/Outlet Area Facility

The Riley Ridge methane sales pipeline launcher is located in Sublette County, Wyoming at GPS coordinates 42.500187 and -110.421826 beginning at MP 0.00. There are no remote controlled valves at this launcher. There is one remote operated emergency shut-in valve operated by the plant facility located upstream of the launcher. There is one pressure relief valve PSV #608 located upstream of the jurisdictional flange to prevent overpressure of the pipeline.

Rand’s Butte Pig Launcher/Receiver Facility

The Rand’s Butte Pig Launcher/Receiver Site is located in Sublette County, Wyoming at GPS coordinates 42.499522 and -110.315282 and located at MP 6.28. The facility consists of an 8” receiver and a 12” launcher. There are no remote operated valves at this location.

Hare’s Ear Receiver Facility

The Hare’s Ear receiver facility is located in Sublette County, Wyoming at GPS coordinates 42.489617 and -110.277651 and located at MP 8.98. The facility consists of a 12” receiver. There are no remote operated valves at this location. There is one remote operated emergency shut-in valve located downstream of the receiver in the Williams Energy compressor site owned and operated by Williams Energy.

Steps to Take when Catastrophic Failure and Damage Occur

For fire located near or directly involving a pipeline facility, explosion occurring near or directly involving a pipeline facility, and accidental release of hazardous liquid or Gas use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee and public safety

Step 3

- Isolate facility – Tab # 16 (Form 1900-07)

Step 4

- Assess threats – What's going on here?

Step 5

- Establish NIMS Response Structure – Complete Tab # 11 (Form 1900-02)

Step 6

- Assess Damage

Step 7

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Step 8

- Restore Service

Steps to Take when Operational Failure Causing a Hazardous Condition Occur

For **non-scheduled releases from stationary or mobile sources** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee and public safety
- Establish a perimeter
- Work with Law Officials for traffic control entering exclusion zone
- Clear roadways for emergency vehicles

Step 3

- Isolate facility – Tab # 16 (Form OM1900-07) (list valves that have been closed/opened)
- Do not approach the impacted area without proper Personal Protective Equipment (PPE) – Tab # 18 (Form 1900-09)
- Monitor wind direction and keep unprotected personnel upwind of spill area
- Use appropriate detection equipment
- Do not drive into vapor clouds
- Do not extinguish primary fires
- Turn off all engines and electrical devices including phones and radios
- Do not attempt to operate any pipeline valves
- Do not approach liquid or vapor cloud without proper PPE – Tab # 18 (Form 1900-09)

Step 4

- Establish NIMS Response Structure, if necessary – Complete Tab # 11 (Form 1900-02)

Step 5

- Assess Damage

Step 6

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Step 7

- Restore Service

For **major accidents involving company vehicles or contractor-owned equipment** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Make every attempt to contact the police and file a report. You should try to obtain a copy of the police report.

Step 3

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Steps to Take when Operational Failure Causing a Hazardous Condition Occur

For **bomb threats** use the following steps as a guide.

Step 1

- By Telephone: Do Not Hang Up! Remain Calm
- Take caller seriously.

Step 2

- Ask a lot of questions – Complete Tab # 17 (Form 1900-08)

Step 3

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

For **Gas/CO₂/H₂S detected inside or near a building** use the following steps as a guide.

Step 1

- Call supervisor -Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee and public safety
- Establish a perimeter
- Use appropriate detection equipment
- Do not drive into vapor clouds
- Do not approach liquid or vapor cloud without proper PPE – Tab # 18 (Form 1900-09)

Step 3

- Once the source of the detected gas has been determined, investigate, repair and return to service.

Step 4

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

For **threats against employees or company facilities** use the following steps as a guide.

Step 1

- Call supervisor -Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC -Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Avoid provoking or obstructing demonstrators.
- Secure your area
- Continue with normal routine as much as possible.
- If the disturbance is outside, stay away from doors or windows. Stay indoors!
- Prepare for evacuation or relocation.

Step 3

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

For **fatalities or multiple hospitalizations involving employees or the public** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Steps to Take when Operational Failure Causing a Hazardous Condition Occur

For **unauthorized active encroachments on company property** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Steps to Take when Natural Disasters Affecting Pipeline Facilities Occur

For **floods** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee safety
- Do not park vehicles near stream and washes during sever storm warning

Step 3

- Isolate facility – Tab # 16 (Form OM1900-07) (listing valves that have been closed/opened)

Step 4

- Assess Damage

Step 5

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Step 6

- Restore Service

For **damaging storms (hurricanes, tornados, etc.)** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee safety
- Move to interior of building away from doors and windows

Step 3

- Isolate facility – Tab # 16 Form OM1900-07 (listing valves that have been closed/opened)

Step 4

- Assess Damage

Step 5

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Step 6

- Restore Service

Steps to Take when Natural Disasters Affecting Pipeline Facilities Occur

For **weather extremes (cold, blizzards, heat)** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee safety

Step 3

- Isolate facility – Tab # 16 (Form OM1900-07) (listing valves that have been closed/opened)

Step 4

- Assess Damage

Step 5

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Step 6

- Restore Service

For **lightning and wildfires** use the following steps as a guide.

Step 1

- Call supervisor - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call DCC - Phone numbers contained on Tab # 10 (Form 1900-01)
- Call 911

Step 2

- Secure Area
- Ensure Denbury Employee safety

Step 3

- Isolate facility – Tab # 16 (Form OM1900-07) (listing valves that have been closed/opened)

Step 4

- Assess Damage

Step 5

- Chronological Record of Emergency: First Facts – Complete Tab # 14 (Form 1900-05)

Step 6


- Restore Service



**INFORMATION CONTACTS AND
VERIFICATION OF PLAN**

For further information about the Emergency Response Plan, evacuation, response to emergency events or other information regarding area / facility emergencies contact the following people:

NAME	TITLE	TELEPHONE
Lost Cabin Plant		
DCC (Denbury Control Center)	Operations	
Russell Grauberger	Pipeline Foreman	
Brandon Duty	Pipeliner	
Curtis Cole	Mechanic/Measurement Technician	
Bruce Augustine	Business Unit Manager	
Jason Davis	District Manager	
Dominic Walker	HSE Supervisor	
Gary Sponsler	HSE Supervisor	
Greencore & Grieve Pipelines		
DCC (Denbury Control Center)	Operations	
Russell Grauberger	Pipeline Foreman	
Scott Crowley	Pipeliner/Measurement Technician	
Brandon Duty	Pipeliner	
Curtis Cole	Mechanic/Measurement Technician	
Coby Rideout	Corrosion Technician	
Bruce Augustine	Business Unit Manager	
Jason Davis	District Manager	
Dominic Walker	HSE Supervisor	
Gary Sponsler	HSE Supervisor	
Riley Ridge Pipeline		
Denbury Control Center (DCC)	Operations Control	
Riley Ridge Control Center	Plant Control	
Russell Grauberger	Pipeline Foreman	
Scott Crowley	Pipeliner/Measurement Technician	
Brandon Duty	Pipeliner	

NAME	TITLE	TELEPHONE
Curtis Cole	Mechanic/Measurement Technician	
Bruce Augustine	Business Unit Manager	
Jason Davis	District Manager	
Dominic Walker	HSE Supervisor	
Gary Sponsler	HSE Supervisor	

The Emergency Response Plan must be reviewed with all employees at least annually.

Name of Facility: Rocky Mountain Region ERP; Lost Cabin Plant and Greencore, Grieve, and Riley Ridge Pipelines

Date of Initial Plan Development: 6/20/16

Date of Last Review for Plan Accuracy: 8/29/2018

Date of Last Revision: 1/3/2019

Facility Operations Manager Name: Russell Grauberger

Facility Operations Manager Signature: Russell Grauberger

Date of Signature: 1/4/2019



FACILITY PERSONNEL RESPONSIBILITIES

Facility Name:		Issue Date:
TITLE	NAME	RESPONSIBILITIES DURING AN EMERGENCY
Incident Commander		
Incident Commander Alternate		
In addition, as personnel are available:		
Site Safety Coordinator	_____	
On-Site Coordinator	_____	
Logistics/Planning Coordinator	_____	
Financial/Administrative Coordinator	_____	
As required by HAZWOPER:		
Technician Level Responder	_____	
Technician Level Responder Alternate	_____	
Operations Level Responder	_____	
10. Operations Level Responder Alternate	_____	
Other Facility/Area Personnel:		
Person in Charge		
District Foreman		
Rescue Personnel:		
Medical Personnel:		
Other Area/Facility/Regional Personnel:		
Area/Region Safety Coordinator:		

At a minimum, identify personnel to fulfill the following responsibilities:

- 1) Incident Command as detailed in the ERP; Technician, Operations Level Responders and Alternates as applicable.
- 2) Person in Charge as detailed in the ERP
- 3) Operations Manager as detailed in the ERP
- 4) Area/Facility Personnel as detailed in the Area/Facility ERP
- 5) Who will isolate the area/facility impacted by the emergency event
- 6) Who will establish the Media Center and media security
- 7) Who will coordinate post-accident drug/alcohol testing
- 8) Who will coordinate providing short-term humanitarian assistance
- 9) Who will schedule and coordinate training drills
- 10) Who will schedule and coordinate annual review of ERP



PRIMARY NOTIFICATION OF CONTACTS

Issue Date: 6/20/16
Revision Date: 1/3/2019

PRIMARY NOTIFICATION:

Control Center Number 1-888-651-7647
307-276-3148 (Riley Ridge Plant Control)

IF NO ANSWER:

Control Center Back-up 972-673-2119 (ALL pipelines and the Lost Cabin Plant) or
Control Center Cellular 469-315-2548 (DCC emergency cell)
Control Center Fax
Control Center E-Mail User ID dcc@denbury.com

PRIMARY CONTACT (If other than Control Center)

Name/Number: Russell Grauberger (ALL Pipelines and the Lost Cabin Plant)
Other Number: 307-439-1850 ext. 4504 (Casper Office)

IF NO ANSWER

Name/Number: Jason Davis (cell) 601-718-6226 (office)
Other Number:
Area/Facility Supervisor Russell Grauberger
Area/Region HSE Coordinator Gary Sponsler

When you note an emergency, call the Denbury Control Center (DCC) as soon as possible. The DCC's number is attended 24 hours each day and as the DCC is prepared to notify all concerned Company personnel, you may proceed with more urgent matters.

Each office should maintain a current Company Telephone Information Directory and Denbury Emergency Call List at each telephone to provide needed information during an emergency.

You may wish to enter additional numbers below that you anticipate needing in an emergency. If you do so, be sure to keep this information up-to-date.

ADDITIONAL EMERGENCY NUMBERS

NAME/OFFICE	NUMBER
Greencore/Grieve Pipelines, Lost Cabin Plant	
Gary Sponsler – Safety Lead	
Nolan Olson – Land Agent	
Chad Docekal – Pipeline Regulatory	
BNSF Railroad Emergency Number	
WYDOT (Wyoming Department of Transportation)	
Wyoming Highway Patrol	
Randy Robichaux – Information Officer	
Dominic Walker – HSE Supervisor	
Riley Ridge Pipeline	
Chad Docekal – Pipeline Regulatory	
Randy Robichaux – Information Officer	
Williams	

WARNING: Anyone not directly involved in the emergency must refrain from using the Company radios and telephones or telephoning area/facility personnel unless absolutely necessary.



EMERGENCY CONTACTS

NAME OF FACILITY: Rocky Mountain Region **Issue Date:** 6/20/16

Facility	Latitude	Longitude
Lost Cabin Plant	Start: 43.171.34 N	Start: 107.369.19 W
Greencore	Start: 43.2831 End: 45.1080	Start: 107.6002 End: 105.0944
Grieve	Start: 42.7361 End: 42.7339	Start: 107.0678 End: 107.0095
Riley Ridge	Start: 42.5001 End: 42.4896	Start: 110.4218 End: 110.2776

NAME & LOCATION OF COMPANY OR AGENCY		PHONE NO.
ALL EMERGENCIES Call 911 or 9-911		
Lost Cabin Plant		
Air Life	City: Casper State: WY	307-577-7201/800-442-2222
Hospital	City: Riverton State: WY	307-856-4164
Hospital	City: Casper State: WY	307-577-7201
Medical Center	City: Riverton State: WY	307-577-2222
Ambulance Service	City: Riverton State: WY	307-857-3669
County Sheriff	City: Riverton/Fremont State: WY	307-332-5611
State Highway Patrol	City: Statewide State: WY	800-442-9090
Fire Department	City: Lysite State: WY	307-876-2244
Fire Department	City: Riverton State: WY	307-856-3026
Electric Power Company	City: Riverton State: WY	307-856-9426
HAZMAT Service	City: Commerce City State: CO	303-382-1258
Other agencies or people to contact (customers, people living near the R.O.W., etc.)		
Conoco Gas Plant	City: Lost Cabin State: WY	307-876-4132
Colorado Interstate Gas	City: Shoshone State: WY	307-876-2781
Greencore (Gillette) Pipeline		
Air Life	City: Gillette State: WY	888-303-9112
Hospital	City: Gillette State: WY	307-688-1000
Hospital	City: Miles City State: MT	406-233-2600
Hospital	City: Rapid City State: SD	605-342-3280
Medical Center	City: Casper State: WY	307-577-7201

County Sheriff	City: Gillette	State: WY	307-682-7271
County Sheriff	City: Buffalo	State: WY	307-684-5581
County Sheriff	City: Broadus	State: MT	406-436-2333
State Highway Patrol	City: Gillette	State: WY	307-682-4030
State Highway Patrol	City: Glendive	State: MT	406-377-5238
Police	City: Gillette	State: WY	307-682-5155
Fire Department	City: Gillette	State: WY	307-682-5319
Fire Department	City: Buffalo	State: WY	307-684-9058
Fire Department	City: Broadus	State: MT	406-436-2259
Electric Power Company	City: Gillette	State: WY	307-682-1655
HAZMAT Service	City: Gillette	State: WY	307-682-5319
Railroad	City: Gillette	State: WY	307-685-7460
Other agencies or people to contact (customers, people living near the R.O.W., etc.)			
Kevin Collins	City: Gillette	State: WY	307-686-6535
David Magnuson	City: Weston	State: WY	307-682-6291
Jim Oliver	City: Weston	State: WY	307-687-2886
Larry Shippy	City: Weston	State: WY	307-682-7593
Richard Lynde	City: Gillette	State: WY	307-682-3835
Dustin Martinson	City: Gillette	State: WY	307-686-9710
Greencore (Casper) Pipeline			
Air Life	City: Casper	State: WY	307-577-7201/800-442-2222
Hospital	City: Riverton	State: WY	307-856-4164
Hospital	City: Casper	State: WY	307-577-7201
Ambulance Service	City: Riverton	State: WY	307-857-3669
Ambulance Service	City: Casper	State: WY	307-577-7201
County Sheriff	City: Fremont-Riverton	State: WY	307-332-5611
County Sheriff	City: Natrona-Casper	State: WY	307-235-9282
County Sheriff	City: Johnson-BUFFALO	State: WY	307-684-5581
State Highway Patrol	City: Statewide	State: WY	800-442-9090
Fire Department	City: Lysite	State: WY	307-876-2244
Fire Department	City: Riverton	State: WY	307-856-3026
Fire Department	City: Casper	State: WY	307-265-8656
HAZMAT Service	City: Commerce City	State: CO	303-382-1258
Railroad	City: Statewide	State: WY	800-832-5452
Riley Ridge Pipeline			
Sublette County LEPC	State: WY	Contact:	307-367-2284
Big Piney Sheriff Department	State: WY	Contact:	307-276-3450

Marbelton Sheriff Department	State: WY	Contact:	307-276-5448
Pinedale Sheriff Department	State: WY	Contact:	307-307-4378
Wyoming Highway Patrol - Pinedale	State: WY	Contact:	307-367-4422, 800-442-9090
Big Piney Fire Department	State: WY	Contact:	307-276-3409
Marbelton Clinic	State: WY	Contact:	307-276-3306
Pinedale Medical	State: WY	Contact:	307-367-4133
University of Utah – Air Medical	State: UT	Contact:	801-581-2500
Eastern Idaho Regional Medical Center – Air Medical	State: ID	Contact:	208-529-6340
Sublette County Environmental Health Office	State: WY	Contact:	307-367-2754
Sublette County Waste Management	State: WY	Contact:	307-276-5792



CHRONOLOGICAL RECORD OF EMERGENCY: FIRST FACTS

NAME OF FACILITY: _____ DATE OF ACCIDENT: _____
 YOUR NAME: _____ TIME FIRST AWARE: _____

FIRST AWARE/FIRST RESPONDER EMPLOYEE COLLECTS THE FACTS.

IF THE EMERGENCY IS OUTSIDE OF THE PLANT: WHO IS REPORTING THE EMERGENCY?

Name: _____ Address: _____ Phone No. _____
 Called From: _____ Phone No. _____

DESCRIBE THE EMERGENCY:

Did you ESD the Plant?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	TIME
Did you activate the siren?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Can you isolate the problem area?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
CAUTION: Do not risk your life or others until you have a plan.	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	TIME
Is rescue needed?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Is first aid needed?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
If yes, can you move the victim?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Are you in a hazardous environment?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Do you have the proper equipment to proceed without help?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Do you need to call 911?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Are you able to set up an emergency command center?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Who should you contact for assistance?		

LOCAL EMERGENCY RESPONSE AGENCIES		
NAME	PHONE	TIME
Ambulance Svc: City: _____ St: _____		
Hospital: City: _____ St: _____		
Air Life: City: _____ St: _____		
Alternate Hospital: City: _____ St: _____		
POLICE:	11. PHONE	TIME
City Police: City: _____ St: _____		
County Sheriff's Office: City: _____ St: _____		
State Patrol: City: _____ St: _____		
FIRE DEPARTMENT:	PHONE	TIME
Fire Dept: City: _____ St: _____		
COMPANY PERSONNEL:	PHONE	TIME
Control Center: City: _____ St: _____		

NOTE: Notify the Control Center or your Primary Contact as soon as you have the emergency in primary control (e.g., ESD - evacuate - rescue - first aid - isolate fuel source if fire - spill containment to prevent environmental contamination).

Supervisor:		Phone No.	Time
Other Operators:		Phone No.	Time
Other Technicians:		Phone No.	Time
Plant/Facility Manager		Phone No.	Time
	Work:	Home:	
Name HSE Coordinator:		Phone No.	Time
	Work:	Home:	

IF YOU HAVE THE PROBLEM UNDER CONTROL START YOUR EMERGENCY RESPONSE PLAN.

LOCAL RESIDENCES

Resident:	Location:	Phone No.	Time

PIPELINE COMPANY(S) or OTHER AFFECTED COMPANY(S)

Company:	Phone No.	Time

ELECTRICITY

Electric Company:	Phone No.	Time

OTHER ACTION(S) TAKEN - Attach extra sheets if necessary.

Time	Time

EMERGENCY IS UNDER TOTAL CONTROL	
TIME:	DATE:
INCIDENT COMMANDER'S INITIALS:	



Issue Date: 7/5/2016

Refer to Site Plot Plan, which identifies ESD locations.

A. Total emergency shutdown may be actuated manually with any one of the following devices:

Device	Location
ESD #1	N side of control building front door
ESD #2	NW entrance gate
ESD #3	NE entrance gate
ESD #4	SE drive through gate
ESD #5	E door of MCC building
ESD #6	N door of MCC building
ESD #7	NW door of MCC building
ESD #8	N door of compressor building
ESD #9	Meter Skid on Greencore Pipeline
ESD #10	NE door communications building
ESD # 11	SE door communications building
ESD #12	SW door of communications building
ESD #13	
ESD #14	
ESD #15	
ESD #16	
ESD #17	
ESD #18	
ESD #19	

B. Emergency shutdown may be automatically actuated by:

Fire High H2S High LEL

C. The emergency shutdown system is designed to isolate:

Compressors

D. Upon initiation of an emergency shutdown, the following events occur almost simultaneously but not necessarily in the order shown:

- All running equipment will be shutdown
- Suction and Discharge valves will close
- Blow Down vents will open
-
-



FACILITY ISOLATION

Issue Date: 6/20/16

Valves and taps closest to the FACILITY that may have to be closed to isolate the station because of an emergency are listed below:

VALVE NUMBER	MILEPOST (or distance from the facility)	NAME/DESCRIPTION
Lost Cabin Plant		
#1	Lost Cabin Compressor Facility	24" inlet valve
#2		30" inlet valve
#3		10" discharge valve
Greencore Pipeline		
#01	00	Fremont County/MOV Electric with Meter Station L/R, RCV
#02	MP 19	Natrona County/ MOV Electric
#03	MP 33	Natrona County/MOV Electric
#04	MP 39	Natrona County/MOV Control Center Electric, RCV
#05	MP 45	Natrona County/ MOV Electric
#06	MP 64.5	Natrona County/MOV Solar
#07	MP 82.5	Natrona County/MOV Electric
#08	MP 87	Natrona County/MOV Solar
#09	MP 100.5	Johnson County/ MOV Electric
#10	MP 117.5	Johnson County/MOV Solar
#11	MP 138	Johnson County/MOV Electric
Mid -Point	MP 144	Campbell County/MOV Electric
#12	MP 148	Campbell County/MOV Electric
#13	MP 149	Campbell County/MOV Electric, RCV
#14	MP 158	Campbell County/MOV Electric
#15	MP 178	Campbell County/MOV Electric / Control Valve, RCV
#16	MP 179	Campbell County/MOV Electric
#17	MP 200	Campbell County/MOV Electric L/R
#18	MP 206	Campbell County/MOV Electric Solar, RCV
#19	MP 218	Campbell County/MOV Electric
#20 Bell Creek	MP 231	Powder River County/MOV Electric L/R, RCV
Grieve Pipeline		
Launcher		
Receiver		
Riley Ridge Pipeline		
	0.0	Automatic Valve owned/operated by Denbury Riley Ridge Plant
	8.9	Automatic Valve owned/operated by Williams

Identify valves and taps on Site Plot Plan or pipeline map or include a sketch identifying their locations here:



BOMB THREAT CHECKLIST

Name of Facility: _____

Report call immediately to: _____ Phone No. _____

Bomb threat received by: _____ Date _____

Questions to ask	Exact wording of threat
1. When is bomb going to explode?	
2. Where is bomb right now?	
3. What does bomb look like?	
4. What kind of bomb is it?	
5. What will cause it to explode?	
6. Did you place the bomb?	
7. Why?	
8. What is your address?	
9. What is your name?	

THE FOLLOWING INFORMATION REQUIRES OPINION, PERCEPTION AND JUDGMENT. PLEASE GIVE YOUR VERY FIRST IMPRESSIONS (CIRCLE ONE):

CALLER WAS:	Male	Adult	Female	Child
ESTIMATE AGE	Pre Teen	Teenage	20 – 40	40 – 50
	50+			
CALLER'S SPEECH:	Accent	Heavy	Slight	Foreign
	Spanish	Asian	German	Other
	American	Southern	New England	Other
CALLER'S VOICE:	Calm	Soft	Distinct	Angry
	Loud	Slurred	Excited	Ragged
	Laughing	Crying	Rapid	Slow
	Normal	Deep	Nasal	Lisp
	Stutter	Deep Breathing	Familiar	Raspy
	Clearing Throat	Cracking Voice		

BACKGROUND SOUNDS:	Street Noises	Office Machinery	Animal Noises	
	Tele Booth	Kitchen Ware	Voices	Airplane
	Bus	Factory Machinery	Train	Clear
	Music	House Noises	Local	Weather
	Motor	Long Distance	Static	Other
THREAT LANGUAGE:	Well Spoken	Incoherent	Foul	Taped
	Irrational	Message Read by Threat Maker		
REMARKS:				



**ON-SITE EMERGENCY
RESPONSE EQUIPMENT**

EQUIPMENT	LOCATION
SPILL CONTAINMENT	
PPE	On Personnel
SCBA	Crew Trucks
Hand Tools	Crew Trucks
Four Gas Monitors	On Personnel
Cell Phone	On Personnel
Two Way Radios	All Crew Trucks
First Aid Kit	Compressor Building and Control Room
AED	Control Room
Spill Containment Materials	Compressor Building

FIRE EXTINGUISHMENT	
30# ABC on all Company Trucks	
Fire Extinguishers	Throughout Lost Cabin Plant, Control Room

OTHER	



**CONTRACTORS AND
AVAILABLE EQUIPMENT**

For Level II (Major) spills contact HSE for spill response

Issue Date: 6/20/2016

CONTRACTOR NAME/ADDRESS	TELEPHONE	SERVICES	EQUIPMENT	EST. TIME BETWEEN CALL AND ARRIVAL ON SITE
DOT Approved? (if required)				

EXAMPLE:

XYZ Transfer Box 000 No Town, WY 80000 <input type="checkbox"/> YES <input checked="" type="checkbox"/> NO	(307) xxx-xxxx (800) xxx-xxxx	Trucking,	Sideboom, D-7 & D-8 dozers, 25 ton crane, 12-1/2 ton crane, trucks-various	6 hours
---	----------------------------------	-----------	---	---------

Lost Cabin Plant

Rocky Mountain Line Systems (RMLS) 1375 Overlook Drive Mills, WY 82644 <input checked="" type="checkbox"/> YES <input type="checkbox"/> NO	307-232-0105 307-254-1875	Pipeline Services	Heavy Equipment, Welders, Trucks	3-6 hours
Action Motor Sports (Gillette ONLY) 3555 East 2 nd St Gillette, WY 82718 <input type="checkbox"/> YES <input checked="" type="checkbox"/> NO	307-299-2840	Equipment Rental	Alternate Transportation, Right of Way Transportation	6-8 hours

Greencore / Grieve Pipelines

Rocky Mountain Line Systems (RMLS) 1375 Overlook Drive Mills, WY 82644 <input checked="" type="checkbox"/> YES <input type="checkbox"/> NO	307-232-0105 307-254-1875	Pipeline Services	Heavy Equipment, Welders, Trucks	3-8 hours
Action Motor Sports (Gillette ONLY) 3555 East 2 nd St Gillette, WY 82718 <input type="checkbox"/> YES <input checked="" type="checkbox"/> NO	307-299-2840	Equipment Rental	Alternate Transportation, Right of Way Transportation	2-6 hours

Riley Ridge Pipeline

Rocky Mountain Line Systems (RMLS) 1375 Overlook Drive Mills, WY 82644 <input checked="" type="checkbox"/> YES <input type="checkbox"/> NO	307-232-0105 307-254-1875	Pipeline Services	Heavy equipment, welders, trucks	5 hours
--	------------------------------	-------------------	-------------------------------------	---------

OTHER DENBURY FACILITIES WHICH MAY BE ABLE TO CONTRIBUTE EQUIPMENT:

FACILITY NAME/ADDRESS	TELEPHONE	SERVICES	EQUIPMENT	EST. TIME BETWEEN CALL AND ARRIVAL ON SITE
Lost Cabin and Greencore / Grieve Pipelines				
Casper Operations 2310 Oil Drive Casper, WY 82604	307-475-1925 307-439-1850	Pipeliners	Pickup / Hand Tools	2-4 hours
Gillette Operations 513 HWY 50 Gillette, WY 82718	307-670-2142	Pipeliners	Pickup / Hand Tools	2-4 hours
Riley Ridge Pipeline				
Riley Ridge Gas Plant 1 Gopher Ridge Lane Big Piney, WY 83113	307-276-3148 Ext. #4248	Operations Support	Heavy equipment, vehicles, tools	1 hour



EMERGENCY DRILL

Date of Drill/Review: _____ Facility/System Name: _____

Attendees:

Drill *Scenario:

Emergency Equipment/Activities Involved:

- | | |
|--|---|
| <input type="checkbox"/> SCBA | <input type="checkbox"/> Emergency Response |
| <input type="checkbox"/> Portable Fire Extinguishers | <input type="checkbox"/> Plant Shutdown |
| <input type="checkbox"/> Wheeled Fire Extinguishers | <input type="checkbox"/> Equipment Shutdown |
| <input type="checkbox"/> Eye/Face Equipment | <input type="checkbox"/> Hazwoper |
| <input type="checkbox"/> Lockout/Tagout | <input type="checkbox"/> Hazard Communication |
| <input type="checkbox"/> SPCC | <input type="checkbox"/> CPR/First Aid |
| <input type="checkbox"/> Other: _____ | <input type="checkbox"/> Other: _____ |
| <input type="checkbox"/> Other: _____ | <input type="checkbox"/> Other: _____ |

Contacts Made:

Safety Dept.: _____	Operations: _____
Other: _____	Other: _____
Other: _____	Other: _____

Discussion Points:

1. _____
2. _____
3. _____
4. _____
5. _____
6. _____

Training Conducted/Accomplished:

1. _____
2. _____
3. _____
4. _____
5. _____
6. _____

Annual Emergency Response Personnel Review:

	<u>Satisfactory</u>	<u>Unsatisfactory</u>	<u>Comments</u>
Ability to carry out emergency response procedures established under 195.402 & 195.403 and/or 192.605 & 192.615.			
Know the characteristics and hazards of CO2 and/or Natural Gas.			
Recognize conditions that are likely to cause emergencies predict the consequences of facility malfunctions or failures and take appropriate corrective action.			
Takes step necessary to control accidental release of CO2 and/or Natural Gas and minimize toxicity or environmental damage			

Recommendations to improve training:

Supervisor Signature: _____

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1. Applicability

- Gathering
- Processing
- Regulated Onshore Pipelines

2. Scope

This document defines the requirements and provisions of the Denbury Integrity Management Program.

3. Core Information and Requirements

3.1. Introduction

In accordance with Title 49 Code of Federal Regulations Part 195.452 (49 CFR 195.452), Denbury has developed an Integrity Management Program (IMP) to address the integrity management of its carbon dioxide pipelines and pipeline facilities.

This IMP manual addresses pipeline systems referenced in [IMP0100A - Appendix A - Jurisdictional Pipelines and Facilities](#), which have been evaluated and portions of which have been determined to meet the requirements of 49 CFR 195.452(a).

Denbury Onshore, LLC, Denbury Green Pipeline-Texas, LLC, Denbury Gulf Coast Pipelines, LLC and Greencore Pipeline Company, LLC are referred to collectively throughout this manual as "Denbury". Denbury Onshore, LLC is referred to individually throughout this manual as "Denbury Onshore". Denbury Green Pipeline-Texas, LLC is referred to individually throughout this manual as "DGPT". Denbury Gulf Coast Pipelines, LLC is referred to individually throughout this manual as "Denbury Gulf Coast". Greencore Pipeline Company, LLC is referred to individually throughout this manual as "Greencore". DGPT, Denbury Gulf Coast and Greencore have contracted with Denbury Onshore for the use of Denbury Onshore's services and employees on DGPT projects, Denbury Gulf Coast projects, and Greencore projects, respectively, through an operating and administrative services agreement. Therefore, during the performance of such work on DGPT

projects, Denbury Onshore will be a contractor of DGPT, and during the performance of such work on Denbury Gulf Coast projects, Denbury Onshore will be a contractor of Denbury Gulf Coast and during the performance of such work on Greencore projects, Denbury Onshore will be a contractor of Greencore. DGPT, Denbury Gulf Coast, and Greencore have approved Denbury Onshore's manuals and programs as complying with DGPT, Denbury Gulf Coast, and Greencore requirements and policies as well as federal and state laws and regulations. Employees listed in this IMP manual are employees of Denbury Onshore unless otherwise noted.

3.2. Integrity Management Program Overview

In accordance with 49 CFR 195.452, Denbury maintains this written IMP to provide a systematic and repeatable process for managing pipeline integrity. As required by 49 CFR 195.452 (f), the following elements are included in this IMP Manual:

- A process for identifying which pipeline segments could impact a High Consequence Area (HCA) (Section [3.5 - Identifying Segments with Potential HCA Impact](#))
- A Risk Analysis that integrates available pipeline integrity information and evaluates the likelihood and consequence of a failure at "Could Affect" pipelines (Section [3.6 - Risk Assessment Process](#))
- Development and implementation of a baseline assessment plan (Section [3.7 - Baseline and Continual Integrity Assessment Plan](#))
- A continual process of assessment and evaluation to maintain a pipeline's integrity (Section [3.7 - Baseline and Continual Integrity Assessment Plan](#))
- Criteria for repair actions to address integrity issues identified by the baseline assessment, subsequent assessments, and information analysis (Section [3.8 - Pipeline Repair Strategy](#))
- Identification and implementation of preventive and mitigation measures to protect the integrity of HCAs (Section [3.9 - Process for Identification of Preventive and Mitigative Measures](#))
- Methods to measure the program's effectiveness (Section [3.11 - Program Evaluation Measures](#))
- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (Section [3.12 - Qualification of Personnel Reviewing Integrity Assessment Results](#))

Denbury has also incorporated elements, procedures, and guidance found in API Standard 1160, *Managing System Integrity for Hazardous Liquid Pipelines*. API Standard 1160 identifies the following additional elements, which are included in this IMP:

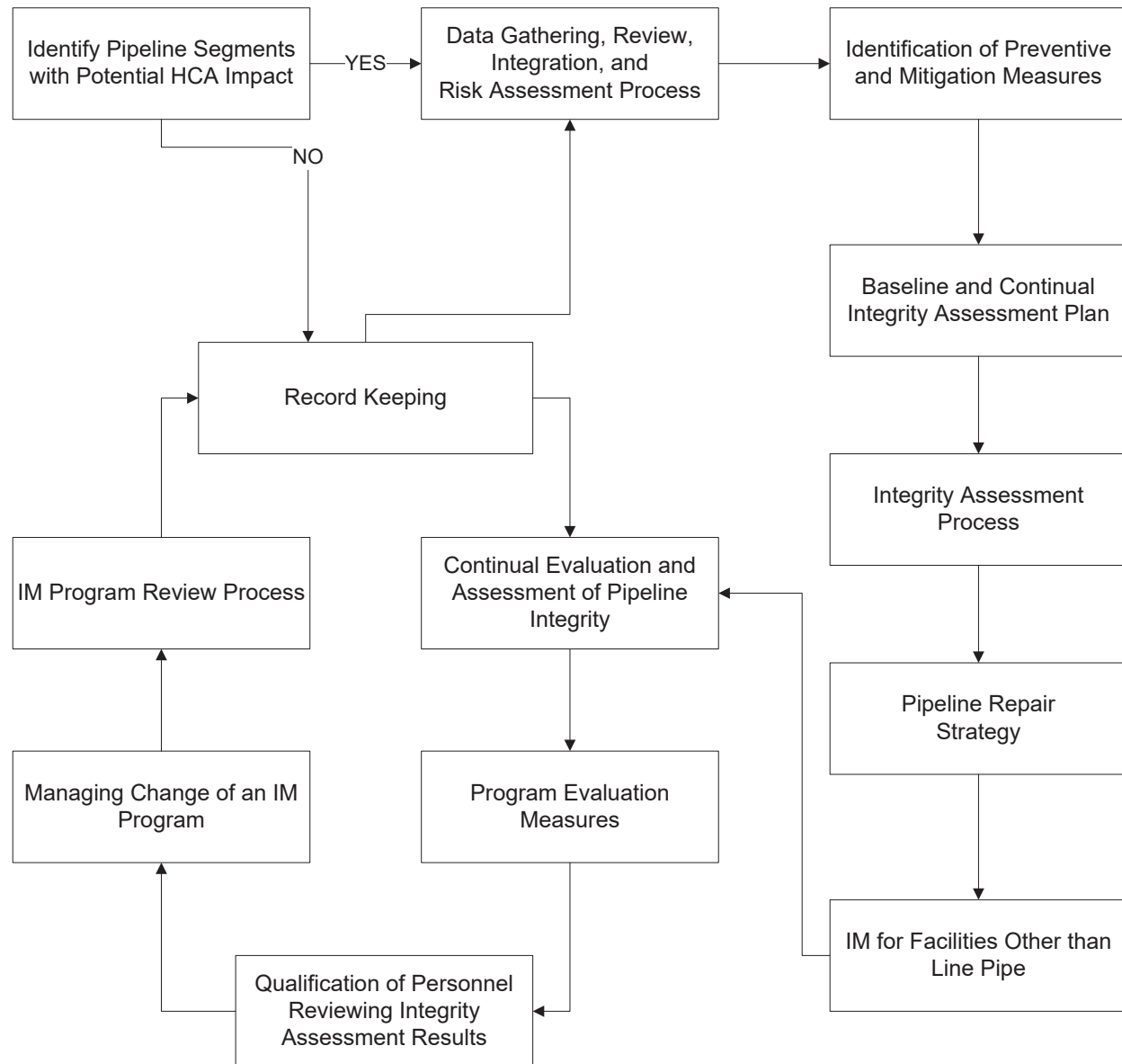
- Integrity management procedures for facilities other than line pipe (Section [3.10 - Integrity Management for Facilities Other than Line Pipe](#))
- Process for managing change (Section [3.13 - Managing Change in an Integrity Program](#))
- Process for reviewing the IMP (Section [3.14 - Integrity Management Program Review Process](#))
- Documentation of elements, procedures, and results of the IMP (Section [3.15 - Record Keeping Procedure](#))

In addition to this IMP, Denbury has developed a number of procedure manuals for inspection, operation and maintenance, and safe operation of its pipelines, which are collectively referred to throughout this document as the Denbury System of Manuals.

This IMP Manual is a living document that changes as the program is revised and improved. Revisions to the IMP are documented in [IMP0100B - Appendix B - Revision Log](#). A flow diagram of the Integrity Management Process is presented in Figure 1 - Integrity Management Program Framework (below).

Figure 1 - Integrity Management Program Framework

INTEGRITY MANAGEMENT PROGRAM



3.3. IMP Roles and Responsibilities

General responsibilities for the IMP Program are described as follows.

Specific responsibilities for each aspect of developing, maintaining, and implementing the IMP are provided, by process/procedure, in [Attachment A – Responsibilities Matrix](#).

A Denbury personnel organization chart is provided in [IMP0100C - Appendix C - Denbury Organization Chart](#).

3.3.1. Integrity Management Engineering Technician

The Integrity Management Engineering Technician has overall responsibility for the development, maintenance, and implementation of the IMP. The Integrity Management Engineering Technician assigns specific integrity tasks to other Denbury personnel and oversees third parties supporting the Denbury IMP.

3.3.2. Pipeline Regulatory Specialist

The Pipeline Regulatory Specialist supports the Integrity Management Engineering Technician with implementation of the IMP and decision-making for IMP processes.

3.3.3. Pipeline Foreman

The Pipeline Foreman supports the Integrity Management Engineering Technician with implementation of the IMP and oversees district pipeline personnel who provide input on validation and decision-making for IMP processes.

3.3.4. Corrosion Foreman

The Corrosion Foreman supports the Integrity Management Engineering Technician with implementation of the IMP and oversees district pipeline personnel who provide input on validation and decision-making for IMP processes. The Corrosion Foreman also has responsibility for conducting integrity assessments and remediation.

3.3.5. Sr. GIS Specialist

The Sr. GIS Specialist supports the IMP with planning and oversight of data management, information systems development, GIS project support, and data gathering and information management of IMP processes.

3.4. Terms, Definitions, and Acronyms

Term	Definition
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, <i>In-Line Nondestructive Inspection of Pipelines</i> , already published. Also see: defect, imperfection.
Category 2	Pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to 49 CFR 195.
Condition	An anomaly confirmed to meet criteria for immediate, 60-day, 180-day, or other repairs.
Confirmed Discovery	When it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.
Defect	An imperfection of a type or magnitude exceeding acceptable criteria. Definition based on API 570 - Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems. Also see: anomaly, imperfection.
Emergency Flow Restriction Device (EFRD)	A check valve or remote control valve as follows: Check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the opposite direction. Remote Control Valve (RCV) means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control center, and the RCV may be actuated by fiber optics, microwave, telephone lines, or satellite.
Facility	That portion of a pipeline that is not line pipe or a mainline block valve or line pipe appurtenance. As an example, a pig launcher, pig receiver, meter station, pump station, or large fenced area containing jurisdictional assets, or combination of these elements is considered a Facility (see Section 3.10 - Integrity Management for Facilities Other than Line Pipe and IMP0100G - Appendix G - "Could Affect" Facility Results).

Term	Definition
Final In-Line Inspection Report	A report provided by the in-line inspection vendor that provides the operator with a comprehensive interpretation of the data from an in-line inspection.
High Consequence Area (HCA)	<p>As defined in 49 CFR 195.450, a location where a pipeline release might have a significant adverse effect on one or more of the following:</p> <ol style="list-style-type: none"> 1) A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists; 2) 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; 3) 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; 4) An unusually sensitive area, as defined in 49 CFR 195.6
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. Also see: anomaly, defect.
Inactive	Pipeline segments that are voided of CO ₂ and filled with inert material (for example inert gas)
Indication	A finding of a nondestructive testing or inspection technique. Definition based on NACE Technical Committee Report, <i>In-Line Nondestructive Inspection of Pipelines</i> "
Maximum Operating Pressure	The maximum pressure at which a pipeline or segment of a pipeline may be normally operated.
Normal Operating Pressure	The predicted pressure (sum of static head pressure, pressure required to overcome friction losses, and any back pressure) at any point in a piping system when the system is operating under a set of predicted steady state conditions.
Operator	A person or entity that owns or operates pipeline facilities
Purged But Active	<p>Disconnected from an active pipeline system, drained and/or flushed or purged with an inert liquid or gas (or in the case of pumping units, with a corrosion-protective fluid) and taken out of service for an extended period of time, but not retired from capital assets.</p> <p>A purged but active facility (pipeline, pump station, meter station, tank, scraper trap, etc.) is not operational without significant re-commissioning effort, and has been effectively removed from service subject to DOT regulations. Accordingly, while purged but active, certain maintenance functions may be performed to maintain the condition of the facility and certain activities, including but not limited to integrity assessments, may be deferred until the facility is returned to service.</p>
Risk	A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

Term	Definition
Risk Assessment	A systematic analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives (See Section 5 - Risk Assessment Process).
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.
Safe Operating Pressure	The pressure, calculated using remaining strength of corroded pipeline formulas, where all corroded regions will withstand a pressure equal to a stress level of 1.39 times the maximum operating pressure.
Subject Matter Expert	A person who by a combination of education, training, and/or experience has knowledge in a particular area(s).
System of Manuals	A series of Denbury manuals that includes: <ul style="list-style-type: none"> • Operations and Maintenance Manual, • Cathodic Protection Maintenance and Inspection Manual, • Emergency Response Procedures Manual, and • Operator Qualification Program
Threat	Factors that can negatively impact pipeline integrity, such as external corrosion, internal corrosion, stress corrosion cracking, manufacturing defects, third party damage, incorrect operations, equipment failures, outside force damage, and construction.
Unusually Sensitive Area or USA	A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release (49 CFR 195.6)

Acronym	Term
CNW	Commercially Navigable Waterway
DW	Drinking Water
EFRD	Emergency Flow Restriction Device
ECO	Ecological Resource Area
GIS	Geographic Information System
HPA	High Population Area
ILI	In-Line Inspection
IMP	Integrity Management Program
MOP	Maximum Operating Pressure
NPMS	National Pipeline Mapping System
OPA	Other Population Area
P&ID	Piping and Instrumentation Diagram

Acronym	Term
P&MM	Preventive & Mitigative Measures
PHMSA	Pipeline and Hazardous Material Safety Administration
PLC	Programmable Logic Controller
RCV	Remote Control Valve
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SME	Subject Matter Expert
SSC	Sulfide Stress Cracking
TPD	Third Party Damage
USA	Unusually Sensitive Area

3.5. Identifying Segments with Potential HCA Impact

In accordance with 49 CFR 195.452 (b)(2), this section establishes a process by which Denbury identifies pipelines and pipeline facilities which “Could Affect” high consequence areas (HCAs) (referred to herein as ““Could Affect” segments” and ““Could Affect” facilities,” respectively). The HCA “Could Affect” identification process includes, but is not limited to, the following critical elements:

- Identification of pipeline segments based on direct impact, indirect impact, or potential transport to an HCA
- Identification of facilities based on direct impact, indirect impact, or potential transport to an HCA
- Validation of identified segments and facilities

3.5.1. Process

High consequence areas (HCAs) are defined by 49 CFR 195.450 as:

- A commercially navigable waterway - a waterway where a substantial likelihood of commercial navigation exists;
- A high population area - 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;
- Other populated areas - a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as incorporated or unincorporated city, town, village, or other designated residential or commercial area; or
- An unusually sensitive area as defined in 49 CFR 195.6 - a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

Initial “Could Affect” segment identification was conducted in accordance with previous versions of the IMP. The annual “Could Affect” segment update process is conducted in accordance with [Section 3.5, Identifying Segments with Potential HCA Impact](#). [IMP Appendix D - “Could Affect” Segment Results](#) contains a list of pipelines, including the stationing range for each defined “Could Affect” segment impact along the length of pipelines identified in [IMP0100A - Appendix A - Jurisdictional Pipelines and Facilities](#). Separate records contain a map for each HCA segment (HCA Maps).

3.5.2. Triggering Events for “Could Affect” Segment Determination

3.5.2.1. Annual Review

On an annual basis, Denbury completes “Could Affect” segment determination for its pipeline segments. Denbury updates HCA information mapped by the NPMS and State data sources as it becomes available. For Denbury pipelines and/or HCA data not defined in the NPMS, new or revised shape files are created and incorporated into this IMP.

3.5.2.2. Change Notification

In the event that HCA, pipeline centerline, or potential release scenario changes are identified outside of the annual review process (Section [3.5.2 - Triggering Events for “Could Affect” Segment Determination](#)), the Integrity Management Engineering Technician initiates “Could Affect” analysis of the potentially affected segments. In accordance with O&M Procedures [OM0000 - Action Decision Committee](#) and [OM0155 – Management of Change](#), changes to pipe characteristics, product transported, or operations may be identified by the MOC process. The Integrity Management Engineering Technician evaluates each MOC request to determine whether “Could Affect” segment determination is required, and communicates limitations/obstacles to the change due to IMP requirements.

3.5.2.3. New / Converted Pipelines

Segments that could affect HCAs are identified prior to the pipeline being placed into service. Following “Could Affect” segment identification, newly constructed pipelines or pipelines converted for service are integrated in this IMP program within one year. For newly constructed pipelines, as-built pipeline data is reviewed after start-up to identify changes that would initiate “Could Affect” segment analysis.

3.5.2.4. Acquired Pipelines

Pipelines obtained through acquisition are reviewed and integrated into this program within one year of assumption of operational responsibility. The Integrity Management Engineering Technician may incorporate acquired pipelines through either of the following methods:

- Accept the previous operator’s IMP (including “Could Affect” segment and facility determination) and continue to maintain acquired pipelines as specified in the previous operator’s IMP
- Schedule “Could Affect” segment and facility analysis and subsequently follow Denbury IMP processes

3.5.2.5. “Purged But Active” Pipelines

Denbury has included all pipeline segments containing CO₂, independent of operational status (i.e., flowing or static), in the current IMP. These pipelines are included in the Continual Assessment Plan (CAP) found in [IMP Appendix E - Continual Assessment Plan](#).

Pipeline segments that are voided of CO₂ and filled with inert material (for example inert gas) are defined as ‘Purged But Active’. Purged But Active pipelines are assessed prior to being placed back into operation as required by this section. This includes the reconfirmation of HCAs. The Integrity Management Engineering Technician verifies the status of Purged But Active pipelines with Operations on an annual basis.

3.5.3. Data Gathering

Annually, at intervals not to exceed 15 months, the Integrity Management Engineering Technician works with the Sr. GIS Specialist to update the mapping data to confirm that the most recent data is available for identifying pipelines that could affect an HCA. During the data update process, the Sr. GIS Specialist verifies that the most current NPMS data is downloaded, base map data is configured, and updates to pipeline centerlines have been incorporated.

3.5.3.1. Compilation of Mapping Data (Software Utilized)

ArcGIS Desktop 10.6.1 software, developed by Environmental Systems Research Institute (ESRI), was used for base map, HCA, and pipeline data compilation and analysis. This software is a Geographic Information System (GIS) featuring seamless data integration with all major vendor formats, on-the-fly coordinate transformation and feature definition, and the ability to perform simple and complex spatial analysis.

The analysis applied buffers around the High Populated, Other Populated, and Ecological areas. Data/polygons were obtained in shapefile format from PHMSA (NPMS). Analysis then determined distances of pipeline travel through these areas.

3.5.3.2. Pipeline Data

Denbury operated pipeline centerlines are available as GIS shapefiles. Updates to the pipeline centerline shapefiles are incorporated into the program on an annual basis following the completion of the annual HCA verification and validation process or as identified throughout the year by change notification. These pipeline centerline shapefiles are used for determining the potential impact to HCAs.

Pipeline operational data is incorporated into “Could Affect” segment and facility analysis. The Integrity Management Engineering Technician obtains and reviews operational data to identify changes that impact “Could Affect” segment determination.

3.5.3.3. HCAs and Sensitive Areas

The Pipeline and Hazardous Materials Safety Administration (PHMSA) identifies HCAs for each of the states in which Denbury operates pipelines. HCA data is available through the PHMSA National Pipeline Mapping System (NPMS). During the HCA validation process, Denbury district corrosion and operations personnel also provide field identification of potential new or expanded HCAs.

3.5.4. Data Validation and Verification

On an annual basis, Denbury incorporates “Could Affect” segment and facility verification information in the “Could Affect” segment re-analysis. The Denbury Integrity Management Engineering Technician transmits maps to the Pipeline Foreman and Corrosion Foreman for final validation.

3.5.4.1. Field HCA Validation

In addition to published data sets, Denbury employs local knowledge and information obtained from Operations SMEs to identify changes that impact “Could Affect” segment determination. Field validation is initiated at the beginning of the data gathering process to determine accuracy of pipeline centerline and HCA data (see [IMP Procedure IMP0400 - New and Existing HCA Validation](#)).

3.5.4.2. Data Completeness and Correctness

Data inputs to the “Could Affect” segment determination process are checked for completeness and data format correctness prior to initiating “Could Affect” segment analysis.

3.5.5. Defining “Could Affect” Segments

“Could Affect” segment determination is completed for each of the potential impact scenarios identified in this section.

3.5.5.1. Direct Impact Zone

Direct impact zones are locations at which the pipeline exists within (intersects with) an HCA. This analysis identifies points at which a pipeline enters and exits an HCA.

3.5.5.2. Indirect Impact Zones

Indirect impact zone analysis consists of air dispersion analysis for CO₂ pipelines. Indirect impact zones are locations at which the pipeline exists within (intersects with) an HCA buffer. This analysis identifies points at which a pipeline enters and exits an HCA buffer.

3.5.5.3. Potential Transport Zones

Denbury pipelines transport CO₂, which vaporizes upon release to air or water, and dissipates or dissociates upon release to water. As such, overland and waterway transport mechanisms do not have the potential to affect an HCA. Air dispersion transport is modeled as detailed in Section [3.5.5.4 - Vaporization Buffer Zones](#).

3.5.5.4. Vaporization Buffer Zones

For “Could Affect” segment and facility identification conducted **prior to May 17, 2011** (revision date for Version 5.0 of the IMP), vaporization buffer zones were determined based on modeling studies conducted for the NEJD pipeline. Details of the modeling process are filed in Denbury’s Regulatory files.

For “Could Affect” segment and facility identification conducted **after May 17, 2011** (revision date for Version 5.0 of the IMP), the Process Hazards Analysis Software Tool (PHASt) evaluation model is employed to determine vaporization buffer zones. A summary of PHAST results for Denbury’s pipelines is included in [IMP0100F - Appendix F3 - Air Dispersion Model for CO₂ Pipelines](#). A description of the PHAST calculations and assumptions are filed in Denbury’s Regulatory files.

Upon completion of the air dispersion model analysis, the worst-case impact is determined for each pipeline segment. Identification of potential impact to HCAs for each segment is based on the worst case condition. Modeled scenarios vary to consider rupture size, MOP, normal and maximum flow rates, and stable or unstable atmospheric conditions.

3.5.6. Identification of “Could Affect” Facilities

Facilities (see definition in Section [3.4 - Terms, Definitions, and Acronyms](#)) include DOT-jurisdictional non-line pipe assets. The Denbury Integrity Management Engineering Technician maintains a listing of DOT regulated facilities in [IMP0100G - Appendix G - “Could Affect” Facility Results](#). Due to the nature of CO₂ releases, a facility is determined to be a “Could Affect” facility if the pipeline into or out of the facility is a “Could Affect” segment, or a “Could Affect” facility boundary intersects an HCA or HCA buffer. The process for identifying “Could Affect” facilities is the same as that for “Could Affect” segment identification. Facility information, including “Could Affect” facility status, is maintained in [IMP0100G - Appendix G - “Could Affect” Facility Results](#).

3.5.7. Reporting “Could Affect” Segments

The Integrity Management Engineering Technician, Pipeline Foremen, and Corrosion Foreman verify that Denbury employees are aware of HCA locations within their respective operating areas and have that information available for their use in daily operations and decision-making activities. Pipeline “Could Affect” segment maps are created by the Sr. GIS Specialist and are maintained on the Denbury intranet by the Integrity Management Engineering Technician.

3.5.7.1. “Could Affect” Segments

“Could Affect” segment maps for pipeline segments are contained on the Denbury intranet site. Additionally, data indicating each pipeline, the pipeline stationing that “Could Affect” an HCA, and the type of HCA potentially affected are also located in [IMP0100D - Appendix D - “Could Affect” Segment Results](#).

3.5.7.2. “Could Affect” Facilities

“Could Affect” Facilities are listed in [IMP0100G - Appendix G - “Could Affect” Facility Results](#). Specific details concerning each “Could Affect” facility can be obtained from the Integrity Management Engineering Technician.

3.5.7.3. “Could Affect” Segment and Facility Validation

Upon completion of “Could Affect” segment and “Could Affect” facility analysis, the Integrity Management Engineering Technician transmits maps to Denbury district personnel for validation in accordance with [IMP Procedure IMP0400 - New and Existing HCA Validation](#). District personnel review the maps to identify changes to the following:

- Pipeline route corrections
- Population center changes (growth or demolition)
- Potential local environmental concerns
- Findings are documented on [IMP Form IMP0400-01 - HCA Validation](#), and transmitted to the Integrity Management Engineering Technician for review and compilation. Revisions are summarized and submitted to the Integrity Management Engineering Technician for approval. The Sr. GIS Specialist updates HCA results.

3.5.8. Exempting “Could Affect” Segments and Facilities

Denbury does not exempt HPA or OPA “Could Affect” segments or facilities.

Denbury believes that the properties of CO₂ minimize the potential to impact ecological resource areas. In contrast with hazardous liquids, CO₂ disperses in air and does not provide long-term effects of contamination to soil or water habitats on a case-by-case basis. Denbury evaluates ecological resource areas to determine if a CO₂ release could impact the species, habitat, or ecological system of concern. The evaluation process involves identifying potentially impacted ecological resource areas through the “Could Affect” segment identification process, compiling ecological resource area attribute and source data from NPMS, contacting source agencies for detailed information regarding species/category for the area, and determining the impact from CO₂ release for that category/species. Results are summarized in [IMP0100H - Appendix H - Ecological Resource Area Report](#).

Additionally, CO₂ releases from CO₂ pipelines are identified as not impacting drinking water or commercially navigable waterways. Primary hazards associated with CO₂ releases (i.e., oxygen deficient atmosphere) do not apply to a release into water, as CO₂ readily dissipates or dissociates from water.

3.6. Risk Assessment Process

In accordance with 49 CFR 195.452 (g), this section establishes a process by which Denbury evaluates pipeline and facility risk. In order to determine risk, Denbury evaluates both the likelihood of a release and the consequences of that release. The Denbury risk evaluation process includes, but is not limited to, the following components:

- A) Data Acquisition
- B) Data Validation
- C) Input of Data into Risk Model
- D) Risk Analysis (Run risk model to calculate segment risk)
- E) Risk Results Validation (Review and validation of risk model results)
- F) Risk Algorithm Reviews (Risk model/algorithm reviews)

3.6.1. Data Acquisition

Denbury personnel are responsible for the collection of integrity assessment and risk related data as described in the Denbury System of Manuals and IMP documentation. The Integrity Management Engineering Technician and Sr. GIS Specialist enter the appropriate information and data into the pipeline databases.

Data sources for utilization in the integrity assessment process will typically include the following:

- A) Results of previous assessments: Internal Inspections (defect type, size, and growth; [O&M Procedure OM0235 - Pigging Operations](#), [O&M Procedure OM0916 – In-Line Inspections](#)), Pressure Testing ([O&M Procedure OM1600-C1135 – Strength and Leak Testing](#), [Construction Standard C1130 - Pressure Testing](#)), ECDA ([O&M Procedure](#)

- [OM0920 - External Corrosion Direct Assessment](#)), or other technology approved for use by PHMSA.
- B) Pipe size, material, pipe manufacturer, coating, pipe condition, seam type
- C) Leak history, repair history
- D) Product transported, product characteristics
- E) Operating stress level
- F) Existing or projected activities in area ([IMP Procedure IMP0400 - New and Existing HCA Validation](#))
- G) Local environmental factors ([IMP Procedure IMP0400 - New and Existing HCA Validation](#))
- H) Geo-technical hazards
- I) Physical supports/spans
- J) Elevation and terrain
- K) Exposure to pressure > MOP (control center records)
- L) Valve location
- M) HCA data changes and growth
- N) O&M activity documentation and records
- O) Operator Error
- P) Incident investigation results ([O&M Procedure OM0159 – Emergency Reporting and Investigation](#))

3.6.2. Data Correctness and Completeness

The Integrity Management Engineering Technician reviews data for completeness and correctness (valid data format) and documents the review on the risk analysis Data Audit Report and Data Completeness Report.

3.6.3. Risk Model

The risk model software database stores integrity assessment-related information which is utilized for the annual risk assessment analysis. [IMP0100I - Appendix I - Risk Analysis Results](#), contains a detailed process for updating the risk model software and conducting risk ranking.

The Denbury risk algorithm is capable of evaluating both the likelihood of failure (LOF) and the consequences of failure (COF), as shown in **Table 1 - Risk Factors** (below). Each risk factor shown in the table can be further sub-divided into additional detailed variables (such as coating design, age, type, cathodic protection data, etc.).

Table 1- Risk Factors

Likelihood of Failure	Consequence of Failure
External Corrosion	Impact on Environment
Internal Corrosion	Impact on Population
Third Party	
Equipment	
Construction	
Manufacturing	
Incorrect Operations	
Weather and Outside Forces	
Stress Corrosion Cracking	

Denbury populates the American Innovations software database, Risk Intelligence Platform™ (RIPL), with selected variable information from the above listed variables for “Could Affect”

sections. For a more detailed description of risk variables employed, refer to [IMP0100J - Appendix J - Risk Algorithm](#).

During the risk assessment process, complete and detailed information may not be available for some data fields. In these instances, one of two actions is taken;

- A) A reasonable engineering assumption is made to populate the data. These assumptions are noted in the comment field.
- B) The factor weighting is set to zero so that the factor has no affect in the analysis conducted using the algorithm.

Denbury's current practice prescribes that pipeline integrity data is incorporated in the risk database even though similar data may not be uniformly available for all line segments included in [IMP0100A - Appendix A - Jurisdictional Pipelines and Facilities](#).

3.6.4. Risk Assessment Results Review and Validation

To verify that the risk assessment methodologies for pipeline segments produce results that are consistent with the goals and objectives of the assessment, the Integrity Management Engineering Technician coordinates a quality assurance review of the preliminary relative risk results with district personnel.

In the event that pipeline segment results are deemed invalid, the input data is re-evaluated as soon as practicable. Until the review team conducts the re-assessment and resolves the uncertainty issues, the invalid results are used as information placeholders only, and the risk analysis report is considered preliminary. Once the results are deemed acceptable, the report is finalized and the Integrity Management Engineering Technician risk ranks the pipeline segments.

3.6.4.1. District Risk Validation

As a component of risk results validation, the Integrity Management Engineering Technician coordinates a review of the threats identified and overall risk rank for each pipeline segment with the Pipeline Foremen and Corrosion Forman to obtain feedback from Denbury district personnel. Pipeline and HCA maps, preliminary risk results, and rankings are presented to district personnel during the District Risk Validation Process. [IMP Form IMP0510-02 - Risk Results Validation](#), is employed to facilitate and document discussion with district personnel.

3.6.5. Risk Model Reviews

Annually, the Integrity Management Engineering Technician coordinates an algorithm review in accordance with [IMP Procedure IMP0500 - Review Risk Algorithm](#). The intent of the review is to verify that the risk algorithm includes appropriate risks/threats to the pipeline operation and reflects Denbury most current views and philosophies. The Integrity Management Engineering Technician reviews and approves the revised algorithm with input from subject matter experts (SMEs).

3.6.6. Facility Risk Assessment

"Could Affect" facility risk evaluations are completed on DOT-jurisdictional non-line pipe assets on an interval not to exceed 5 years. The Integrity Management Engineering Technician evaluates facility risk in accordance with [Section 3.10 - Integrity Management for Facilities Other than Line Pipe](#).

3.7. Baseline and Continual Integrity Assessment Plan

In accordance with 49 CFR 195.452 (c) and (j), this section establishes the baseline integrity assessment plan and a continual process of evaluation and assessment by which Denbury maintains pipeline integrity following the baseline integrity assessment. The continual process of evaluation and assessment includes, but is not limited to, the following elements:

- Development of risk based assessment intervals

- Selection of risk based assessment methods
- Periodic evaluations of pipeline segments
- Data integration and information analysis

3.7.1. Process

As part of its process for continual evaluation of “Could Affect” segments, Denbury conducts integrity assessment to determine the condition of its pipelines. [IMP0100E - Appendix E - Continual Assessment Plan](#), contains results of the assessment planning process.

3.7.2. Risk-Based Assessment Interval Selection

Denbury establishes risk-based assessment intervals up to a maximum of five years (not to exceed 68 months) for continuously evaluating pipeline integrity ([IMP Form IMP0620-02 - Assessment Planning](#)). The assessment interval is based on the potential risk posed to the high consequence areas and on the following:

- Results of the 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 (e.g., corrosivity of soil, subsidence, climatic)
- Geo-technical hazards
- Physical support of the segment such as by a cable suspension bridge
- Addition or removal of valves

3.7.3. Threat-Based Assessment Method Selection

Denbury employs several methods to assess pipeline integrity. Depending on the threat(s) identified in the risk analysis process, the most suitable assessment method(s) for addressing the specified threat(s) is selected.

Denbury [IMP Procedure IMP0600 - Select Appropriate Assessment Tool and Vendor](#), lists the assessment methods used to determine pipeline integrity after an integrity threat is identified and it is determined that the associated risk must be more accurately quantified to allow for proper remediation and Preventive and Mitigative Measures (P&MM) selection.

Pipeline segments with multiple threats may require the use of multiple inspection techniques. In accordance with 49 CFR 195.452 (j)(5), only the following methods of integrity assessment are employed:

- Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves. The type of internal inspection tool selected is based on the threat assessment capability, limitations, and performance specifications of the tool. A process for employing ILI tools is included in [O&M Procedure 0235 - Pigging Operations](#).
- Pressure test conducted in accordance with 49 CFR 195.452 subpart E, [Construction Standard C1130 - Pressure Testing, and OM1600/C1135 – Strength and Leak Testing](#).
- External corrosion direct assessment in accordance with 49 CFR 195.588 and Denbury [O&M Procedure OM0920 – External Corrosion Direct Assessment](#).
- Other technology that Denbury demonstrates can provide an equivalent understanding of the condition of the line pipe. If Denbury utilizes other technology as an assessment method PHMSA will be notified 90 days prior to conducting the assessment per notification requirements specified in 49 CFR 195.452(m).

In the event that Denbury determines that other technology is appropriate to evaluate a particular threat, the requirements for investigation of potential defects identified using other

technology will be developed as appropriate. The process will include requirements for vendor specifications, validation of results, data analysis, data integration requirements, defect identification, and prioritization, prioritization of excavations, etc.

Denbury has identified the assessment methods in **Table 2 - Assessment Methods** (follows), as appropriate methods to inspect for threats to Denbury “Could Affect” segments.

Table 2 - Assessment Methods

Defect Type	Magnetic Flux Leakage			Ultrasonic		Caliper	Pressure Testing	External Corrosion Direct Assessment
	Standard Resolution	High Resolution	Transverse Field	Compression Wave	Shear Wave			
External General Corrosion	X	X	X	X	X		X ¹	X
External Pitting	X	X	X	X	X		X ¹	X
Internal Pitting	X	X	X	X	X		X ¹	
Gouging	X	X	X	X	X		X ¹	X ²
Dents with Metal Loss		X	X	X			X ¹	X ²
Dents						X	X ¹	X ²
SCC and Crack-like Defects					X		X ¹	
Lamination/Mid Wall Defects		X	X	X	X		X ¹	

¹ Assumes defects at failure conditions

² Assumes coating damage associated with gouge and dent defects.

3.7.4. Assessment Method Selection

In addition to selecting an assessment method based on identified threats, Denbury also considers the following:

- Threat assessment capability, limitations, and performance specifications of the selected method
- Capability and performance history of the selected method and vendor
- Piggability of the specific pipeline segment
- Operational capability and impact of the selected method
- Previous assessment methods and results
- Industry experience

Rationale for assessment method selection is documented on [IMP Form IMP0620-02 - Assessment Planning](#).

3.7.5. Validation of Assessment Method and Interval Selection

As part of the Denbury annual program evaluation, re-assessment methods and intervals are reviewed and modified, if necessary based on the following:

- New insights from completed assessments
- Data integration results and risk analysis
- Evaluation of new and improved assessment technologies

CAP review and evaluation procedures are provided in [Section 3.14 - Integrity Management Program Review Process](#).

3.7.6. Triggering Events for Initial (Baseline) Assessments

In the event that Denbury identifies a new “Could Affect” segment, constructs new pipeline segments containing a “Could Affect” segment, resumes operation of an inactive “Could Affect” segment, or acquires pipelines containing a “Could Affect” segment, baseline assessments will be incorporated into the continual assessment plan (CAP). Selection of assessment interval and method(s) will be in accordance with this section.

3.7.6.1. New “Could Affect” Segments

Upon having identified a new “Could Affect” segment, the Integrity Management Engineering Technician evaluates assessment history to determine if an integrity assessment and subsequent remediation have previously been completed. Additionally, a data integration review of known and potential threats for the new “Could Affect” segment and the current assessment schedule are reviewed to determine if a shorter assessment interval or alternate methodology might be necessary.

In the event that integrity assessment is not planned for a newly identified “Could Affect” segment, a baseline assessment plan is developed within one year of identification, and the corresponding baseline assessment is completed within five years of identification.

In the event that an in-line inspection has been completed previously for the newly identified “Could Affect” segment, the Integrity Management Engineering Technician assigns and schedules review of ILI and repair data to identify and appropriately schedule for evaluation any anomalies meeting regulatory or internal criteria for evaluation. Discovery of the condition, in these cases, is documented as the completion date of the data review assigned by the Integrity Management Engineering Technician.

Upon review by the Integrity Management Engineering Technician, ILI data and repair evaluations may be postponed if an assessment has been recently completed or is pending.

3.7.6.2. New / Converted Pipelines

Baseline assessments for newly constructed or converted to service pipelines containing “Could Affect” segments are completed before the pipeline begins operation. Baseline assessment methods are selected as described in [Section 3.7.3 - Threat-Based Assessment Method Selection](#), and [IMP Procedure IMP0600 - Select Appropriate Assessment Tool and Vendor](#). Within the first 12 months of operation, Denbury incorporates the “Could Affect” segment into the IMP. Newly constructed or ‘converted to service’ pipelines containing “Could Affect” segments are fully integrated into this IMP within one year.

3.7.6.3. Inactive / Idle Pipeline Segments

Denbury includes idle pipeline segments that “Could Affect” an HCA (purged and isolated, but not abandoned) in the CAP. Baseline assessments for reactivated pipeline segments containing “Could Affect” sections are completed before the pipeline resumes operation. Selection of assessment method(s) is in accordance with this section.

In the event that an idle pipeline segment containing “Could Affect” segments (not flowing, but containing product) is acquired, it will be purged and classified as inactive, purged and abandoned, or treated the same as any active “Could Affect” segment.

3.7.6.4. Newly Acquired Pipelines

Until Denbury has integrated newly acquired pipeline segments into its assessment plan, Denbury will meet the schedule established by the previous owner/operator. During the integration process, Denbury evaluates the completed assessments and planned reassessments to determine if changes to the assessment schedule or method(s) are required.

3.8. Pipeline Repair Strategy

In accordance with 49 CFR 195.452(h), this section establishes a process by which Denbury addresses conditions in areas that “Could Affect” HCA segments on Interstate and Intrastate Pipelines. For areas outside of “Could Affect” HCA segments, refer to [O&M Procedure OM0213 - Leaks, Pipe and Weld Defects, Repairs](#) for repair criteria. The remediation process includes, but is not limited to, the following critical elements:

- Establish discovery date
- Develop prioritized remediation schedule
- Complete repairs

3.8.1. Discovery of a Condition

Denbury considers “discovery” to be when the Integrity Management Engineering Technician or Corrosion Foreman has enough information to determine that a condition exists, which meets the criteria for an immediate, 60-day, or 180-day condition.

Discovery can be on an anomaly-by-anomaly basis, by groupings (types) of anomalies, or for the length of the inspected segment. Available information may include, but is not limited to field evaluation, communication with the ILI vendor, or anomaly correlation. Discovery will occur no later than 180 days after a completed integrity test, and is documented by the Integrity Management Engineering Technician or Corrosion Foreman. The Integrity Management Engineering Technician or Corrosion Foreman is responsible for documenting the receipt date of all preliminary and final assessment reports.

In the event that discovery is not declared within the 180-day allowance, the Integrity Management Engineering Technician or Corrosion Foreman is responsible for documenting the circumstances.

Note: Upon written notification from the data analyst that an immediate condition could exist, the Integrity Management Engineering Technician or Corrosion Foreman initiates immediate investigation. Investigation includes, but is not limited to data gathering, further communication with vendor, anomaly correlation, and/or field excavation.

3.8.2. Requirements for Repairs Scheduling

Repair conditions are scheduled for evaluation and repair following discovery as follows:

- A) Immediate conditions are evaluated and remediated immediately following discovery. Additionally, the Integrity Management Engineering Technician or Corrosion Foreman contacts the District Manager to coordinate initiation of temporary pressure reduction or line shutdown until the immediate condition is repaired.
- B) 60-day conditions are investigated and remediated, if necessary, within 60 days of discovery.
- C) 180-day conditions are investigated and remediated, if necessary, within 180 days of discovery.

Other conditions are investigated and remediated as determined necessary based on the results of data integration.

Repairs are completed according to a schedule that prioritizes the conditions for evaluation and remediation. **Table 3 - Repair Condition Criteria** (below), presents a summary of conditions for each repair condition category. In the event that the actual repair/remediation schedule extends beyond the original prioritized schedule, the Integrity Management Engineering

Technician or Corrosion Foreman documents the reasons why the original prioritized schedule cannot be met and that the change does not jeopardize public safety or the environment. Schedule extensions are communicated to the Integrity Management Engineering Technician. Denbury will notify PHMSA and state agencies as necessary, if regulatory mandated repair schedules per 195.452(h) cannot be met and additional protection cannot be provided through a temporary reduction in operating pressure.

Table 3 - Repair Condition Criteria

Criteria	Description
Immediate	<ul style="list-style-type: none"> • Metal loss greater than 80% of the nominal wall regardless of dimensions. • Metal loss with a burst pressure less than the established MOP at the location of the condition. • Dents located on the top of the pipeline (above 8 and 4 o'clock) with any indication of metal loss, cracking, or a stress concentrator • Dents greater than 6% of the nominal diameter located on the top of the pipeline (above 8 and 4 o'clock). • A condition that in the judgment of the evaluator requires immediate action.
60-Day	<ul style="list-style-type: none"> • Dents greater than 3% of the nominal diameter (greater than 1/4-inch on nominal diameters less than 12-inches located on the top of the pipeline (above 8 and 4 o'clock). • Dents on the bottom of the pipeline (below 8 and 4 o'clock) with any indication of metal loss, cracking or a stress concentrator • A condition that in the judgment of the evaluator requires action within 60 days.
180-Day	<ul style="list-style-type: none"> • Dents greater than 2% of the nominal diameter (greater than or equal to 1/4-inch on nominal diameters less than 12-inches) affecting pipe curvature at a longitudinal seam weld or a girth weld. • Dents greater than 2% of the nominal diameter (greater than or equal to 1/4-inch on nominal diameters less than 12-inches) on the top of the pipeline above 8 and 4 o'clock. • Dents with depths greater than 6% of the nominal diameter on the bottom of the pipeline (below 4 and 8 o'clock). • Metal loss with a calculated safe operating pressure that is less than the established MOP at the location of the condition. • Predicted metal loss greater than 50% in an area of general corrosion. • Predicted metal loss greater than 50% at crossings of another pipeline. • Predicted metal loss greater than 50% with widespread circumferential corrosion. • Predicted metal loss greater than 50% that could affect a girth weld. • A potential crack indication that when excavated is determined to be a crack. • Corrosion of or along the longitudinal seam weld. • A gouge or groove greater than 12.5% of the nominal wall. • A condition that in the judgment of the evaluator requires action within 180 days.

Criteria	Description
Other Conditions	<ul style="list-style-type: none"> • A condition that has changed since the previous assessment • Mechanical damage or dents located on the top of the pipeline (above 8 and 4 o'clock) • A condition abrupt in nature. • A condition longitudinal in orientation. • A condition that extends over a large area. • A condition located in or near a casing. • A condition located in or near a crossing of another pipeline. • A condition located in or near an area with suspect cathodic protection.

3.8.3. Temporary Pressure Reductions

Upon discovery of immediate conditions, the Integrity Management Engineering Technician or Corrosion Foreman initiates immediate repair. Additionally, the Integrity Management Engineering Technician or Corrosion Foreman contacts the District Manager to coordinate initiation of temporary pressure reduction or line shutdown until the immediate condition is repaired.

Denbury Engineering calculates safe operating pressure using the formula in Section 451.7 of ASME/ANSI B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*. The calculated safe operating pressure is then employed to determine the temporary pressure reduction value. In the event that remaining-strength calculations cannot be performed due to anomaly type (such as possible dents with metal loss, or metal loss greater than 80%), the pressure is lowered to no more than 80% of the operating pressure actually experienced at the location of the condition within the two months preceding the inspection.

The Integrity Management Engineering Technician notifies the District Manager to initiate pressure reduction or line shut down. Temporary pressure reductions are communicated to the following Denbury personnel by the District Manager:

- Pipeline Operations Superintendent
- Pipeline Foreman
- District operations personnel
- Denbury Control Center

In the event that a temporary pressure reduction is taken in conjunction with an immediate condition, Denbury attempts to correct that condition within 365 days. The Integrity Management Engineering Technician monitors temporary pressure reductions associated with repairs. For a reduction in operating pressure anticipated to exceed 365 days, the Integrity Management Engineering Technician notifies PHMSA and state agencies as necessary, as provided in 49 CFR 195.452(m) and documents further remedial action taken to maintain the safety of the pipeline segment.

3.9. Process for Identification of Preventive and Mitigative Measures

In an effort to better protect high consequence areas and in accordance with 49 CFR 195.452 (f)(6) and 49 CFR 195.452(i), this procedure establishes a process by which Denbury identifies and implements Preventive and Mitigative Measures (P&MMs). This process includes, but is not limited to, the following critical elements:

- Evaluation of Risk Information
- Identification of Additional Actions (P&MMs) that protect public safety and/or the environment
- Implementation of P&MMs

P&MM identification and implementation are based on risk information. Subsequently, P&MMs reduce risk by addressing specific risk drivers along particular pipeline segments.

3.9.1. Process

Upon receiving final information from the risk process (3rd quarter of each year or as needed for new construction or conversion projects), P&MMs are evaluated for their sufficiency and effectiveness by means of a risk based review process. Additional P&MM evaluations are conducted in response to reportable releases. This process includes the following steps:

- Current P&MM review
- Additional P&MM consideration (EFRDs, leak detection, and other P&MMs)
- Documentation and justification
- Implementation of additional P&MMs

Pipeline segments determined to have sufficient P&MMs require no additional P&MMs be recommended for consideration during P&MM evaluation. The basis for P&MM sufficiency is documented on [IMP Form IMP800-01 - P&MM Evaluation](#). The Integrity Management Engineering Technician is responsible for maintaining associated records in appropriate segment files.

Segments found to be candidates for additional P&MMs are further evaluated by the Integrity Management Engineering Technician and P&MM evaluation team. The team considers each of the three P&MM categories (EFRDs, leak detection, and other P&MMs) by employing a risk-based analysis. The Denbury risk assessment model integrates segment specific information and has the ability to generate P&MM strategies into “scenarios”. These scenarios are utilized to evaluate the benefits (in reduced risk) for given P&MMs. Subsequently, the most appropriate P&MMs are selected for the particular risk drivers.

Implementation of selected P&MMs is assigned to responsible parties and documented on [IMP Form IMP800-01 - P&MM Evaluation](#). P&MMs are tracked to completion by the Integrity Management Engineering Technician.

3.9.2. EFRDs & Leak Detection Review

EFRDs and leak detection capabilities are critical components of the P&MM review process, as the speed at which pipeline leaks can be detected and the pipeline isolated is directly related to release volumes and potential impacts to HCAs. During the P&MM evaluation, Denbury SMEs determine whether further evaluation of leak detection and EFRDs is needed.

3.9.2.1. Leak Detection

Denbury reviews the required factors listed in 49 CFR 195.452 (i)(3) to determine the necessity of improved leak detection. [IMP Form IMP0800-02 - Leak Detection Evaluation](#), provides a more detailed discussion of the leak detection evaluation process. [IMP0100K - Appendix K - Leak Detection System Evaluation](#), provides an overview of available leak detection systems for consideration.

3.9.2.2. EFRDs

The Denbury risk model is employed to evaluate the anticipated potential impact on HCAs. This information and other factors as described in 49 CFR 195.452(i)(4) are reviewed by Denbury to determine the feasibility of risk reductions by changes to the SCADA system and/or the relocation or addition of EFRDs. [IMP Form IMP0800-03 - EFRD Evaluation](#), provides a more detailed discussion of the EFRD evaluation process.

In accordance with PHMSA guidance, when Denbury determines that EFRDs are needed on a pipeline segment to mitigate the effects of a hazardous liquid pipeline release in an HCA, they are installed.

3.9.3. Facility P&MM

Facility P&MM evaluations are completed on other (non-pipe) pipeline facilities in accordance with [Section 3.10 - Integrity Management for Facilities Other than Line Pipe](#).

3.10. Integrity Management for Facilities Other than Line Pipe

This process provides guidelines for Denbury to conduct a comprehensive “Could Affect” Facility Risk Analysis and Preventive and Mitigative Measures (P&MM) evaluation.

The process is intended to:

- A) Identify threats to the integrity of the applicable facilities
- B) Determine risk associated with identified threats
- C) Evaluate the effectiveness of existing P&MMs
- D) Identify additional P&MMs, if needed

3.10.1. Process

Facility risk assessment and P&MM evaluations are completed on an interval not to exceed five years for “Could Affect” facilities. The primary goals of the Facility Risk Assessment Review are to identify the facility threats, select P&MMs for implementation, and determine whether the facility increases line pipe risk.

3.10.2. Data Gathering and Validation

In preparation for the facility risk assessment, the Integrity Management Engineering Technician and district personnel compile the following facility documentation, if available:

- Facility Response Plans (e.g., Spill Response Plans, Emergency Response Plans, Security Plans, Contingency Plans)
- Facility Release Reports for DOT-regulated equipment and assets
- Incident Reports other than releases with emphasis on incidents with multiple occurrences (e.g., abnormal operating reports, near miss reports)
- Applicable inspection reports (e.g., exposed pipe, atmospheric corrosion inspections, tank inspections, non-destructive testing (NDT) examinations, cathodic protection surveys, internal corrosion coupon reports)
- P&MMs currently in use at the facility
- Information pertaining to the facility equipment (e.g., materials, type of valve, coating type, plot plans, piping diagrams, equipment lists)
- Operating information (e.g., pressures, product types, unplanned upset events, procedures)
- Facility Security (e.g., plans, programs)
- Facility HCA information (e.g., maps with HCA overlays)
- Other data as appropriate

Facility Review Team Members evaluate the facility documentation for completeness and accuracy. In the event that facility documentation does not accurately represent actual operations or equipment, action items are assigned to update the facility documentation accordingly.

3.10.3. Risk Assessment

The likelihood of a “Could Affect” facility release is evaluated for each of the following threats:

- Equipment/Non-pipe Malfunction or Failure
- Pipe – Corrosion (external, internal, and atmospheric)
- Pipe – Outside Force Related Failure (outside force (excavation) damage, security-related damage, and natural force damage)
- Operations (material receipts and deliveries, operator error, and instrumentation/relief devices)
- Other Causes

Consequences of a release are evaluated for ecological and population impacts.

3.10.4. Preventive and Mitigative Measures (P&MM) Evaluation

For each “Could Affect” facility P&MM evaluation, the following systematic steps are employed:

- Threat Identification
- Review of Current Threat Based P&MMs
- Evaluation of Additional P&MMs
- Determine Impact on Facility Risk
- Implement and Track P&MMs

The facility review team identifies currently implemented P&MMs on [IMP Form IMP0900-01 - Facilities Risk Evaluation](#), for each threat. Each current and potential P&MM is evaluated to determine the impact on risk based on the integrated facility data. During the review, additional P&MMs may be proposed for consideration and documented in the appropriate threat category.

Note: Additional risk reduction activities should also be considered, if needed. (Increased inspections, additional operator training or development of operating procedures, increased frequency of routine maintenance, enhanced corrosion control practices, enhanced leak detection efforts, enhanced back-flow prevention equipment, etc.).

An implementation decision for each proposed P&MM is documented on the [IMP Form IMP0900-01 - Facilities Risk Evaluation](#), along with the justification to implement or not implement the measure. The Integrity Management Engineering Technician documents implementation responsibility and tracks each item to completion.

3.11. Program Evaluation Measures

In accordance with 49 CFR 195.452 (f)(7) and 49 CFR 195.452 (k), this section establishes a process by which Denbury implements a method to measure the program's effectiveness. The process includes, but is not limited to, the following critical elements:

- Process Approach
- Performance Metrics
- Root Cause Analysis

3.11.1. Process

Denbury continually evaluates its pipeline integrity management program in accordance with the following sections.

3.11.2. Performance Measures

Denbury collects and analyzes performance measures annually. Performance measures are reviewed during the annual IMP review to identify modifications and establish goals.

Performance measures are used to evaluate the effectiveness of the IMP and are broken into three categories: leading, lagging, and deterioration. Leading performance measures evaluate how effectively the IMP is implemented (surveillance and preventive activities, number of one-calls, operator training, etc.). Lagging performance measures evaluate historical data (leak history, incident response, product loss, etc.). Deterioration performance measures are trends that indicate weakening integrity of a system despite preventive measures (inadequate one-call response, ECDA results, ILI tool run results, etc.).

When establishing performance measures and goals, the following criteria are considered:

- Reduce the total volume of unintended releases.
- Reduce the total number of unintended releases.
- Document the percentage of Integrity Management activities completed during the calendar year.
- Track and evaluate the effectiveness of Denbury's outreach activities
- Internal audits of pipeline systems (third party or Denbury personnel)
- External audits of pipeline systems (audits by regulatory agencies)
- Operational events (e.g. relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity
- Demonstrate that the integrity management program supports continuous risk reduction activities with a focus on high risk items. As assessments, repairs, and procedural or

process changes are made, operating risk for individual segments and pipelines should be reduced.

- Demonstrate that the integrity management program for facilities supports continuous risk reduction activities with a focus on high risk items.
- Descriptions of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative.
- Provide increasingly useful decision-making assistance and information by suggesting effective preventive and mitigative strategies.

The Integrity Management Engineering Technician, with input from the Supervisor, Pipeline Services, District Manager, Pipeline Foremen, and Corrosion Foreman, selects performance measures and establishes performance goals. Performance measures are assigned to Denbury personnel for data gathering and reporting to the Integrity Management Engineering Technician. A summary table of performance measures is contained in [IMP0100L - Appendix L - Performance Measures](#).

3.11.3. Audit Guidance

Auditing of Denbury's integrity management program may be conducted by Denbury personnel, contactors, or regulatory agencies. Audits conducted by regulatory agencies are incorporated into the Integrity Management Program Evaluation, as these audits often reveal valuable insights into the effectiveness of the integrity management program. Therefore, any audit findings, favorable or unfavorable, are considered and documented by the Integrity Management Engineering Technician.

Internal audits (audits conducted by Denbury personnel or outside contractors) are also a component of the program evaluation and are scheduled at the discretion of the Integrity Management Engineering Technician but at intervals no less than once every 3 calendar years. For audits conducted by either outside contractors or Denbury personnel, the Integrity Management Engineering Technician is responsible for evaluating and selecting competent auditors.

3.11.4. Lessons Learned

Root cause analysis is an integral part of risk management methodology and is used to evaluate the root causes of possible hazards or accidents. Investigation results for incidents or releases concerning the integrity of the pipeline system are critical metrics that are considered by the Integrity Management Engineering Technician during program evaluations.

3.11.5. Benchmarking

The Integrity Management Engineering Technician annually reviews Denbury performance against other operator reported performance. Information is obtained from regulatory agencies and industry organizations (e.g. AOPL, API committees).

Benchmarking is a structured approach for identifying the best practices from industry and government, and comparing and adapting them to the organization's operations. Such an approach is aimed at identifying more efficient and effective processes for achieving intended results, and suggesting new goals for program and process improvement.

3.12. Qualification of Personnel Reviewing Integrity Assessment Results

In accordance with 49 CFR 195.452 (f)(8), this section establishes a process by which Denbury ensures qualified personnel evaluate integrity assessment results. The process includes, but is not limited to, the following critical elements:

- Qualification Requirements
- Vendor Screening

3.12.1. Process

Denbury verifies the qualification of personnel reviewing integrity assessment results for each integrity assessment project on [IMP Form IMP1100-01 - Qualification Verification](#).

3.12.2. Qualification of Results Review Personnel

The Integrity Management Engineering Technician or Corrosion Foreman assigns qualified individuals to review and analyze information generated from integrity assessments. Denbury personnel or contractors who review integrity assessment results must meet the following minimum requirements:

- Three years of relevant experience:
 - Completing data integration activities
 - Reviewing ILI, ECDA, and hydrostatic assessment data
 - Reviewing field documentation (i.e., rubbings and PDER forms)
- Project experience during the previous 12-month period
- Knowledge of applicable regulations
- NACE Level II or higher certification (for ECDA only)

In the event that an individual does not meet the qualification requirements, additional training or skill acquisition is planned and scheduled by the Integrity Management Engineering Technician or Corrosion Foreman. An individual that does not meet each of these requirements may work under the direct supervision of a qualified person who meets each of the aforementioned criteria.

3.12.3. Vendor Qualification

Denbury only selects vendors whose personnel associated with the operation, evaluation, and analysis of the selected assessment method are competent with respect to qualification, education, training, experience, and knowledge.

ILI Vendor Results Review Process and personnel are to be qualified in accordance with ANSI/ASNT ILI-PQ-2005, *In-line Inspection Personnel Qualification and Certification Standard*, and API 1163, *In-line Inspection Systems Qualification Standard*.

ECDA vendor personnel reviewing Indirect Inspection results must maintain a NACE Level II or higher certification. ECDA vendor field personnel conducting Indirect Inspections must maintain a NACE Level I or higher certification, or be supervised by an individual with NACE Level I or higher certification.

Vendor personnel using Other Technology who are reviewing indirect inspection results must maintain a NACE Level II or higher certification or other appropriate equivalent certification agreed to by the Denbury Project Manager. Vendor field personnel using Other Technology and conducting indirect inspections must maintain a NACE Level I or higher certification or other appropriate equivalent certification agreed to by the Denbury Project Manager, or be supervised by an individual with NACE Level I or higher certification or other appropriate equivalent certification agreed to by the Denbury Project Manager. An individual that does not meet these requirements may work under the direct supervision of a qualified person who meets each of the aforementioned criteria. Vendor qualifications review and documentation is part of the vendor selection and data integration processes.

3.13. Managing Change in an Integrity Program

As discussed in API Standard 1160, *Managing System Integrity for Hazardous Liquid Pipelines*, Denbury employs a formal Action Decision Committee (ADC) process to identify changes relevant to integrity management. The ADC process includes, but is not limited to, the following critical elements:

- Recognize changes before or shortly after they occur
- Identify changes which affect pipeline risk
- Update IMP elements to reflect changes

Denbury follows a formal ADC process for communication of changes affecting Denbury pipelines as specified in [O&M Procedure OM0001 – Standards Modification](#) and on [O&M Form OM0000-01 - Action Decision Committee Request](#). This process is used for all changes to this Integrity Management Program.

3.14. Integrity Management Program Review Process

In accordance with 49 CFR 195.452 (f), this section establishes a process by which Denbury continually changes the IMP to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. The process includes, but is not limited to, the following critical elements:

- Written Program Review
- Risk Results Review
- CAP Review
- Other integrity-related issues

3.14.1. Process

The IMP review process encompasses the written program and associated procedures, as well as output from IMP activities conducted throughout the year. An IMP review meeting is held periodically, and a comprehensive report of the meeting discussion is prepared and distributed to IMP stakeholders. [IMP Form IMP1300-01 - Annual IMP Report](#), is employed to document the meeting discussion.

3.14.2. Written Program Review

The IMP is continually evaluated and revised as necessary to reflect operating and industry experience, conclusions drawn from Integrity Management Process Results, and to incorporate tools and techniques as they become available. The Integrity Management Engineering Technician facilitates program review, and receives input from Denbury personnel with IMP responsibilities.

Overall IMP review and revision is completed periodically. Review and revision is also conducted as necessary to incorporate regulatory changes, lessons learned during incident investigation/root cause analysis, and in response to other changes in the Denbury pipeline system.

Approval and communication of changes to the IMP are conducted through the ADC process specified in [O&M Procedure OM0001 – Standards Modification](#) and on [O&M Form OM0000-01 - Action Decision Committee Request](#). This process is used for all changes to this Integrity Management Program.

A listing of changes made to the IMP is maintained in the [IMP0100B - Appendix B - Revision Log](#).

The electronic IMP is maintained by the Integrity Management Engineering Technician on the Denbury intranet.

3.14.3. Risk Analysis Review

As a component of the Annual IMP Review, a summary of risk analysis results and pipeline risk rankings is prepared. Review Team Members consider the relative risk of the pipeline segments and identify apparent inconsistencies in the overall ranking with SME knowledge of the pipeline systems. Documentation from risk analysis review is employed in [IMP Procedure IMP0500 - Review Risk Algorithm](#). Action items resulting from risk analysis review may include, but are not limited to, additional data gathering, algorithm modification, or additional P&MM evaluation.

3.14.4. CAP Review

With input from the Corrosion Foreman and Integrity Management Engineering Technician, the Review Team evaluates the CAP to determine whether planned integrity assessments account for pipeline relative risk and threats identified during the risk analysis review. Results from previous integrity assessments, root cause analysis, and conditions identified on similar segments are considered by SMEs in determining whether the overall CAP is appropriate. Action items resulting from CAP review may include, but are not limited to, modifications to

planned assessments (timing or method), investigation of new technology, or additional P&MM evaluation.

3.14.5. Performance Measure Review

Performance measure review completed during the annual IMP review process is conducted to review effectiveness of the IMP, determine the value added by current performance measures, identify new performance measures, and establish goals for future periods. Trending and evaluation results are employed during process review to consider modifications to the written program and associated procedures.

3.15. Record Keeping Procedure

In accordance with 49 CFR 195.452 (I), this section establishes a process by which Denbury maintains IMP documents. The process includes, but is not limited to, the following critical elements:

- Document Submittal
- Records Retention

For additional detail on documentation requirements related to IMP, refer to [Section 5 - Documentation](#).

3.15.1. Process

The Integrity Management Engineering Technician maintains the IMP written program. The Pipeline Regulatory Specialist maintains other IMP records, including documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement, and evaluate each element of the IMP. [IMP0100M - Appendix M - Document Retention Schedule](#), specifies the retention period, retention location, and responsibility for each record required in the IMP. The following guidelines provide document control:

- 3.15.1.1. Files stored in the Pipeline Office of Records shall be protected from unauthorized access, weather, and other damage.
- 3.15.1.2. Electronic records (as available) shall be maintained and backed up locally and remotely.
- 3.15.1.3. Original records shall not be removed from the file storage area without proper authorization. As necessary, copies of originals are permitted to be removed from the file storage area.
- 3.15.1.4. Document review by government agencies or third parties is supervised.

4. Training

The Integrity Management Engineering Technician develops and revises training materials and schedules integrity management training for employees. Training is documented on the Meeting Sign-In Sheet.

5. Documentation

Denbury maintains IMP-related records for the life of the pipeline. The following specific records are included:

5.1. HCA Analysis Maps and Records

- [IMP0100D - Appendix D - "Could Affect" Segment Results](#)
- [IMP0100F - Appendix F3 - Air Dispersion Buffers](#)
- [IMP0100G - Appendix G - "Could Affect" Facility Results](#)
- [IMP0100H - Appendix H - Ecological Resource Area Report](#)
- HCA Validation Forms
- "Could Affect" Segment and Facility Validation Forms

5.2. Risk Analysis Records

- Risk Model Spreadsheets/Databases
- [IMP0100I - Appendix I - Risk Analysis Results](#)
- [IMP0100J - Appendix J - Risk Algorithm](#)
- Data Audit Report
- Data Completeness Report
- Risk Validation Form

5.3. Assessment Planning Records

- [IMP0100E - Appendix E - Continual Assessment Plan](#)
- Assessment Planning Forms

5.4. Repair Records

Specific recordkeeping requirements can be found in [Engineering Standard E1700 - Project Closure Documentation](#) and include:

- Condition Classification
- Condition Discovery Dates
- Repair Records

5.5. Preventive and Mitigative Measures (P&MM) Evaluation Records

- P&MM Evaluation Forms
- Leak Detection Evaluation Forms
- EFRD Evaluation Forms

5.6. “Could Affect” Facility Risk Analysis

- Facilities Risk Assessment and Preventive and Mitigative Measures forms

5.7. Program Evaluation Records

- Performance Measure Reports
- Audit Reports

5.8. Personnel Qualification Records

- Qualification Verification Forms

5.9. IMP Review Records

- IMP review reports

5.10. Written IMP and Related Documentation

- Written Program, Procedures, and Forms
- Document Retention Schedule

6. References

- 49 CFR 195.450
- 49 CFR 195.452
- 49 CFR 195.588
- 49 CFR 195.6
- American Innovations Software Database, Risk Intelligence Platform™ (RIPL)
- ASME/ANSI B31.4 - Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
- ANSI/ASNT ILI-PQ-2005, In-line Inspection Personnel Qualification and Certification Standard
- API 570 - Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems
- API 1160 - Managing System Integrity for Hazardous Liquid Pipelines
- API 1163 - In-line Inspection Systems Qualification Standard

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- ArcGIS Desktop 10.2 Software (developed by Environmental Systems Research Institute - ESRI)
- NACE Technical Committee Report - In-Line Nondestructive Inspection of Pipelines
- NACE SP0102-2010 – Standard Practice, Inline Inspection of Pipelines
- NACE SP0204-2008 – Standard Practice, Stress Corrosion Cracking (SCC) Direct Assessment Methodology
- PHAST Evaluation for CO₂ Pipelines (see Denbury's Regulatory files)
- TX Administrative Code (TAC), Title 16, Chapter 8.101-Pipeline Safety Regulations
- [Construction Standard C1130 - Pressure Testing](#)
- [Engineering Standard P0005 - Introduction](#)
- [Engineering Standard E1700 - Project Closure Documentation](#)
- [O&M Procedure OM0000 - Action Decision Committee](#)
- [O&M Procedure OM0001 – Standards Modification](#)
- [O&M Procedure OM0155 – Management of Change](#)
- [O&M Procedure OM0159 – Emergency Reporting and Investigation](#)
- [O&M Procedure OM0213 - Leaks, Pipe and Weld Defects, Repairs](#)
- [O&M Procedure OM0235 - Pigging Operations](#)
- [O&M Procedure OM0916 – In-Line Inspections](#)
- [O&M Procedure OM0920 - External Corrosion Direct Assessment](#)
- [O&M Procedure OM1600-C1135 – Strength and Leak Testing](#)
- [O&M Form OM0000-01 - Action Decision Committee Request](#)
- [IMP Procedure IMP0400 - New and Existing HCA Validation](#)
- [IMP Procedure IMP0500 - Review Risk Algorithm](#)
- [IMP Procedure IMP0600 - Select Appropriate Assessment Tool and Vendor](#)
- [IMP Form IMP0400-01 - HCA Validation](#)
- [IMP Form IMP0510-02 - Risk Results Validation](#)
- [IMP Form IMP0620-02 - Assessment Planning](#)
- [IMP Form IMP0800-01 - P&MM Evaluation](#)
- [IMP Form IMP0800-02 - Leak Detection Evaluation](#)
- [IMP Form IMP0800-03 - EFRD Evaluation](#)
- [IMP Form IMP0900-01 - Facilities Risk Evaluation](#)
- [IMP Form IMP1100-01 - Qualification Verification](#)
- [IMP Form IMP1300-01 - Annual IMP Report](#)

6.1. Appendices to the Denbury Integrity Management Plan (Incorporated by Reference)

- [IMP0100A - Appendix A - Jurisdictional Pipelines and Facilities](#)
- [IMP0100B - Appendix B - Revision Log](#)
- [IMP0100C - Appendix C - Denbury Organization Chart](#)
- [IMP0100D - Appendix D - “Could Affect” Segment Results](#)
- [IMP0100E - Appendix E - Continual Assessment Plan](#)
- [IMP0100F - Appendix F3 - Air Dispersion Model for CO₂ Pipelines](#)
- [IMP0100G - Appendix G - “Could Affect” Facility Results](#)
- [IMP0100H - Appendix H - Ecological Resource Area Report](#)
- [IMP0100I - Appendix I - Risk Analysis Results](#)
- [IMP0100J - Appendix J - Risk Algorithm](#)
- [IMP0100K - Appendix K - Leak Detection System Evaluation](#)
- [IMP0100L - Appendix L - Performance Measures](#)
- [IMP0100M - Appendix M - Document Retention Schedule](#)



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Attachment A – Responsibilities Matrix

Responsible Parties:	Integrity Management Engineering Technician	District Manager	Pipeline Regulatory Specialist	Pipeline Foremen	Corrosion Foreman	Sr. GIS Specialist
IMP Activity <u>Identifying Segments with Potential HCA Impact</u>	<ul style="list-style-type: none"> Develop and maintain procedures for identifying pipeline segments that "Could Affect" an HCA Develop and maintain procedures for identifying pipeline facilities that could affect an HCA Approve field validation modifications to HCAs Initiate the HCA Validation process per Section 3.5.1 - P-Process Coordinate all aspects of the HCA Validation process through to completion Update intranet with "Could Affect" segment and "Could Affect" facility maps Receive validation reports and documentation from district personnel Implement and track revisions to final maps and records based on field validation 	<ul style="list-style-type: none"> Participate in risk model/algorithm reviews Assist with data gathering Participate in validating threats and relative risk rankings 	<ul style="list-style-type: none"> Assist with data gathering Coordinate threat/risk validation with district personnel 	<ul style="list-style-type: none"> Designate district personnel to assist with validating HCAs Assist with communicating segments or facilities that could affect HCAs to district personnel 	<ul style="list-style-type: none"> Designate district personnel to assist with validating HCAs Schedule and coordinate HCA field data gathering with district personnel Assist with communicating segments or facilities that could affect HCAs to district personnel 	<ul style="list-style-type: none"> Update GIS databases with current source data (NPMS, USGS, etc.) Prepare maps identifying pipeline segments and facilities that could affect an HCA Update intranet with "Could Affect" segment and "Could Affect" facility maps
<u>Risk Assessment Process</u>	<ul style="list-style-type: none"> Develop and maintain Risk Assessment Procedures Review and approve Threat/Risk Validation Develop and maintain risk model/algorithm for risk analysis Coordinate algorithm review meetings and document modifications Gather data for risk analysis Complete risk analysis and relative risk ranking Assist with data gathering Designate district personnel to assist with validating threats and relative risk rankings 	<ul style="list-style-type: none"> Participate in risk model/algorithm reviews Assist with data gathering Participate in validating threats and relative risk rankings 	<ul style="list-style-type: none"> Assist with data gathering Coordinate threat/risk validation with district personnel 	<ul style="list-style-type: none"> Assist with data gathering Designate district personnel to assist with validating threats and relative risk rankings 	<ul style="list-style-type: none"> Designate district personnel to assist with validating HCAs Schedule and coordinate HCA field data gathering with district personnel Assist with communicating segments or facilities that could affect HCAs to district personnel 	<ul style="list-style-type: none"> Assist with data gathering from GIS databases Identify and maintain pipeline databases and information systems employed for records storage



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Revised: 2019-09-04

Responsible Parties:	Integrity Management Engineering Technician	District Manager	Pipeline Regulatory Specialist	Pipeline Foreman	Corrosion Foreman	Sr. GIS Specialist
IMP Activity Baseline and Continual Integrity Assessment Plan	<ul style="list-style-type: none"> Develop and maintain assessment planning procedures Approve assessment plans Recommend reassessment interval and method for completed assessments Oversee assessment implementation and review of results Facilitate assessment plan reviews Maintain assessment plan documentation, including decision rationale 			<ul style="list-style-type: none"> Assign district personnel to participate in assessment plan reviews 	<ul style="list-style-type: none"> Recommend reassessment interval and method for completed assessments Assign district personnel to participate in assessment plan reviews Oversee assessment implementation and review of results 	
Pipeline Repair Strategy	<ul style="list-style-type: none"> Develop and maintain pipeline repair procedures Coordinate initiation of temporary pressure reductions or line shutdown as necessary Communicate anomalous conditions through ILI or pressure testing and coordinate repairs Notify the District Manager of immediate conditions 				<ul style="list-style-type: none"> Identify anomalous conditions through ECDA and coordinate repairs Notify the District Manager of immediate conditions 	



INTEGRITY MANAGEMENT PROGRAM
No. IMP0100
Title: Integrity Management Plan
Revised: 2019-09-04

Responsible Parties:	Integrity Management Engineering Technician	District Manager	Pipeline Regulatory Specialist	Pipeline Foreman	Corrosion Foreman	Sr. GIS Specialist
IMP Activity <u>Process for Identification of Preventive and Mitigative Measures</u>	<ul style="list-style-type: none"> Develop and maintain P&MM evaluation procedures Schedule and facilitate P&MM evaluations Complete risk analysis scenarios for potential P&MMs Document P&MM evaluations and decision rationale Monitor implementation of P&MMs 			<ul style="list-style-type: none"> Designate district personnel to assist with P&MM evaluations 	<ul style="list-style-type: none"> Designate district personnel to assist with P&MM evaluations 	
<u>Integrity Management for Facilities Other than Line Pipe</u>	<ul style="list-style-type: none"> Develop and maintain Facility Integrity Management Procedures Approve results of risk assessment and P&MM evaluations Coordinate risk analysis and P&MM evaluations for "Could Affect" facilities Track implementation of P&MMs for facilities 			<ul style="list-style-type: none"> Designate District Personnel to assist with risk analysis and P&MM evaluations 	<ul style="list-style-type: none"> Designate District Personnel to assist with risk analysis and P&MM evaluations 	
<u>Program Evaluation Measures</u>	<ul style="list-style-type: none"> Develop and maintain Program Evaluation Procedures Plan Internal Audits Assist in data gathering for Performance Measures Compile Performance Measure Data Prepare Performance Measure Report 	<ul style="list-style-type: none"> Assist in data gathering for performance measures 	<ul style="list-style-type: none"> Assist in data gathering for performance measures 	<ul style="list-style-type: none"> Assist in data gathering for performance measures 	<ul style="list-style-type: none"> Assist in data gathering for performance measures 	<ul style="list-style-type: none"> Assist in data gathering for performance measures



No. IMP0100
 Title: Integrity Management Plan
 Revised: 2019-09-04

INTEGRITY MANAGEMENT PROGRAM

Responsible Parties:	Integrity Management Engineering Technician	District Manager	Pipeline Regulatory Specialist	Pipeline Foreman	Corrosion Foreman	Sr. GIS Specialist
IMP Activity Qualification of Personnel Reviewing Integrity Assessment Results	<ul style="list-style-type: none"> Develop and maintain personnel qualification requirements Assign sufficiently qualified Denbury personnel to integrity assessment projects Verify contractor personnel assigned to integrity assessment projects are sufficiently qualified 				<ul style="list-style-type: none"> Assign sufficiently qualified Denbury personnel to integrity assessment projects Verify contractor personnel assigned to integrity assessment projects are sufficiently qualified 	
Integrity Management Program Review Process	<ul style="list-style-type: none"> Initiate and facilitate IMP Reviews Identify Review Team Members Provide knowledge of regulatory changes affecting the IMP Initiate the communication and approval process using Denbury MOC/ADC procedures Prepare Annual Review Report Provide insight into Denbury practices Maintain IMP0100B – Appendix B – Revision Log, with details regarding changes to the IMP Manage electronic IMP documents and update the Denbury intranet 	<ul style="list-style-type: none"> Provide insight into Denbury practices 	<ul style="list-style-type: none"> Provide insight into Denbury practices 	<ul style="list-style-type: none"> Provide insight into Denbury practices 	<ul style="list-style-type: none"> Provide insight into Denbury practices 	<ul style="list-style-type: none"> Provide insight into Denbury practices



No. IMP0100
 Title: Integrity Management Plan
 Revised: 2019-09-04

INTEGRITY MANAGEMENT PROGRAM

Responsible Parties:	Integrity Management Engineering Technician	District Manager	Pipeline Regulatory Specialist	Pipeline Foremen	Corrosion Foreman	Sr. GIS Specialist
IMP Activity Record Keeping	<ul style="list-style-type: none"> Develop and maintain record keeping procedures Maintain the document retention schedule for IMP records Prepare and submit IMP documentation for retention Maintain IMP records and files 	<ul style="list-style-type: none"> Prepare and submit IMP documentation for retention 	<ul style="list-style-type: none"> Prepare and submit IMP documentation for retention 	<ul style="list-style-type: none"> Prepare and submit IMP documentation for retention 	<ul style="list-style-type: none"> Prepare and submit IMP documentation for retention 	<ul style="list-style-type: none"> Prepare and submit IMP documentation for retention

Table 2. Potential Permits/Approvals, Revised

Agency	Permit/Approval	Status	Timeline
Federal			
U.S. Army Corps of Engineers	Section 404 permit for dredge/fill in jurisdictional wetlands	Project will qualify for Nationwide Permit 12.	The Project will not result in a total loss of waters of the United States greater than ½-acre, nor an impact of 0.10-acre or more and thus, no preconstruction notification (PCN) is required.
U.S. Fish and Wildlife Service	Consultation and review of the proposed Project regarding impact to federally threatened and endangered species, migratory birds, and bald and golden eagles	Consultation requested and received.	Completed prior to application submittal.
State			
North Dakota Public Service Commission	Certificate of Corridor Compatibility and Route Permit	Application pending.	4 to 6-months
North Dakota Department of Environmental Quality Division	National Pollutant Discharge Elimination System (NPDES) General Permit for Stormwater Discharges Associated with Construction Activity	Submit Notice of Intent at least 7 days prior to construction and develop/implement Stormwater Pollution Prevention Plan.	Typically, the SWPPP is prepared in time to provide information on quantities of erosion and sediment control best management practices (e.g., silt fence, straw wattles, etc.) for use in preparation of pipeline contractor bids. Anticipated preparation date is March 2020.
	NPDES General Permit for Temporary Dewatering/Hydrostatic Testing	Submit Notice of Intent at least 30 days prior to discharge date.	Hydrostatic testing would occur in the late summer/early fall of 2020, so the permit application would be submitted in July 2020.
North Dakota State Historic Preservation Office (SHPO)	Cultural and historic resources consultation and review.	Class I inventory and Class III pedestrian survey completed for the Corridor and SHPO concurrence was received.	All cultural resources investigations were completed and concurrences from SHPO received by September 2019.
	Unanticipated Discovery Plan (UDP) for discovery of human/historic remains.	UDP submitted to SHPO for review/approval and concurrence was received.	
Slope County	Conditional Use Permit (CUP); Section Line Crossing Permit; Road Crossing Permit	CUP application submitted and approval received from Zoning Board and County Commissioner.	Conditional Use Permit issued on 5/1/2019.
Bowman County	Utility Permit for the pipeline; County Road Crossing Permit; Section Line Crossing Permit.	To be obtained prior to Project construction. Utility Permit (which covers County Road and Section Line crossings) application submitted on 4/12/2019.	Utility Permit issued on 7/30/2019
Private			
BNSF Railroad	Railroad Crossing Permit	To be obtained prior to Project construction.	Application to be submitted no later than November 30, 2019, with anticipated permit issuance date of May 1, 2020.

DENBURY LAKE CHARLES PIPELINE LATERAL

16" CO₂ PIPELINE

Public Risk and Pipeline Design Narrative

**DENBURY LAKE CHARLES 16" CO₂ PIPELINE LATERAL
PUBLIC RISK AND PIPELINE DESIGN**

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PUBLIC RISK AND PIPELINE DESIGN

1.0 INTRODUCTION

This narrative describes aspects of the pipeline design, construction, operation, and maintenance with enhancements to minimize potential hazards to the public and to maintain system reliability. Operational procedures, design, and construction features reflecting accepted industry practices that will be used to avoid undue hazards and effects are also discussed.

2.0 PIPELINE SYSTEM DESCRIPTION

The Denbury CO2 Pipeline Lateral will consist of the following primary components: one 11.87-mile long, 16-inch diameter liquid carbon dioxide pipeline, and associated pipeline support facilities including valves for temporary pig launchers/receivers, main line isolation valves, and metering site equipment.

The transport of the CO2 originates within the Lake Charles Clean Fuels facility at a meter station to be operated and controlled by plant personnel. The inlet meter will consist of two 12" parallel orifice meter runs and automated isolation valves. The meter station will be used to measure the flow, composition, moisture content, pressure and temperature of the CO2 stream going into the pipeline from the plant compressor. This information is hard wired to a flow computer and then transmitted into the plant control system, which is monitored 24 hours per day, 7 days per week by trained operators. The measurement data will be monitored by both LCCE and Denbury for purposes of pipeline leak detection and coordinated response to any upset condition that may arise.

Denbury ownership and operation of the CO2 pipeline begins downstream of the meter at a motorized 16" isolation valve with insulating flanges, which isolate the cathodic protection system within the plant from the system employed to protect the pipeline. Denbury assumes operating control at this flange, and all components and operations downstream of this point are Department of Transportation jurisdictional under 49 CFR 195. The motor operated isolation valve will be located within a fenced site at the plant north property boundary and be used to shut in the pipeline for maintenance or an emergency. Operation of the isolation valve can be accomplished both locally and remotely through the pipeline control center using satellite communication. The site also includes manually operated valves for use in maintenance activities.

Once the pipeline leaves the plant boundary, it will be routed through the adjacent industrial properties and under Bayou D'Inde Road to the north using a horizontal directional drill (HDD). The typical depth for a road crossing is at least 5 feet below the road bed and a river/stream crossing is at least 20 feet below the road or stream/river bed (actual HDD depths depend on the length of the drill, maximum allowed curvature of the pipe based on diameter and wall thickness, and minimum clearance and depth required to avoid any obstructions). The pipeline will continue north to Bayou D'Inde where a 16" manually operated isolation valve will be installed within a 25 feet x 25 feet chain link fence. The valve site is equipped with smaller valves on either side of the isolation valve to allow venting of the CO2 in the event that the pipeline requires maintenance that cannot be completed with the pipeline under pressure. The pipeline will cross under Bayou D'Inde using the HDD installation method. Another pipeline isolation valve station configured as described above will be installed north of the bayou.

After crossing Bayou D'Inde, the pipeline route will progress north using conventional trenched construction methods and then cross under Interstate 10 using HDD installation method. The route continues through a mixed commercial and residential area for approximately 1 mile located between Interstate 10 and State Highway 90. The pipeline will be trenched in place and be buried with at least 3 feet of cover or 4 feet near any buildings located within 50 feet of the pipeline. The pipeline will cross under State Highway 90 using a horizontal bore. The pipeline will then parallel the Kansas City Southern (KCS) Railroad ROW and tracks for approximately 4.3 miles through a largely rural area. Additional pipeline isolation valves will be installed in this section and be located on either bank of the Sabine River Diversion Canal with plans to automate one of these valves to allow remote operation in the event of a pipeline emergency. An automated or motorized valve site foot print expands to 40 feet x 25 feet to allow installation of the valve and an accompanying building for satellite and communication controls equipment.

The route will also cross Houston River Road and the Houston River using the HDD installation method. Pipeline isolation valves will be located on either side of the river near Houston River Road and to the north at a site adjacent to the KCS railroad tracks and access road. Neither valve is planned for automation due to the close proximity to other planned automated valves at the Sabine River Diversion Canal and the pipeline end point less than 2.5 miles to the northwest.

Once the route diverts away from the KCS railroad, it will then parallel an existing power transmission corridor for approximately 1.75 miles. Construction of the pipeline in this portion of the route will include installation of an alternating current (AC) mitigation technology in the trench to protect from stray current from the power transmission lines that could impact the integrity of the steel pipe. The pipe will be buried with at least 3 feet of cover, as is expected for the majority of the pipeline route.

The route will turn westward once crossing under Bankens Road, which will be horizontally bored at a depth at least 5 feet below the road bed. The route will parallel the existing Green Pipeline and terminate inside the Lake Charles Pump Station where the custody measurement station will be installed.

The custody meter station will measure the amount of CO₂ received from Leucadia prior to entering the Green Pipeline. downstream of the pumps at the station. The custody meter site will be configured similar to the plant measurement station and include an over pressure protection valve to protect the meter skid and piping. The meter skid will consist of two 12-inch senior orifice fittings, 16-inch isolation valves, motorized valve actuators with remote communication and control, pressure and temperature transmitters, a flow computer, CO₂ sampling and gas chromatograph, and wiring to the pipeline control system. The data gathered by the meter station will then be transferred by satellite to the Denbury control center for monitoring and shared with the Lake Charles Clean Fuels to help facilitate effective pipeline operation and communication.

3.0 INDUSTRY RELIABILITY AND SAFETY OVERVIEW

This section provides a brief overview of the potential hazards, safety standards, and impacts on public safety associated with carbon dioxide pipelines.

3.1 Hazards

Carbon dioxide is colorless and tasteless. It is relatively odorless in low concentrations but has a musty smell in at greater concentrations. It is nontoxic, but is classified as an asphyxiant due to its displacement of oxygen in confined spaces or large concentrations. Extended exposure to

CO₂ in high concentrations can lead to the following symptoms: headache, dizziness, restlessness, breathing difficulty, sweating, malaise, increased heart rate, increased blood pressure, coma, asphyxia, and convulsions.

Unconfined mixtures of carbon dioxide in air are not explosive due to the properties of carbon dioxide. The specific gravity of gaseous carbon dioxide is 1.52 and heavier than air at atmospheric temperatures, thus potentially settling near the ground in low lying areas under colder conditions. Wind and increasing ambient temperatures will disperse carbon dioxide over time.

3.2 Pipeline Incident Data

Operating experience records for hazardous liquid and carbon dioxide pipelines have been maintained for more than 60 years. Construction, operations, and maintenance expertise have provided regulators and the industry with the opportunity to identify specific causes of pipeline failure and to address those through appropriate design, construction, operation, and maintenance practices. The primary categories of failure causes defined by the U.S. Department of Transportation (USDOT) Office of Pipeline Safety (OPS) are:

Outside force or third party damage;
Corrosion (internal and external);
Construction/material defects; and
Operator error or actions.

3.3 Impact on Public Safety

On a per mile basis, CO₂ pipelines have experienced much fewer incidents than natural gas or other hazardous liquid pipelines. Of the incidents that have occurred over the years, public impacts have been relatively minimal and include few injuries and monetary impacts due to environmental damage. Specific effects of past and potential future incidents include:

- CO₂ gas release to atmosphere only
- Exposure of the public, habitat, or species to CO₂ at varying concentrations
- Operational impacts with service deficiencies or interruption

4.0 PROJECT COMPLIANCE WITH APPLICABLE REGULATORY REQUIREMENTS

The proposed pipeline will be designed, constructed, operated, and maintained in accordance with USDOT minimum federal safety standards in 49 CFR Part 195, "Transportation of Hazardous Liquids by Pipeline". The regulations are intended to ensure adequate protection for the public from hazardous liquid and carbon dioxide pipeline failures. Part 195 specifies material selection and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

Some key provisions of the Part 195 regulations are summarized below:

- System materials and design (49 CFR 195 Subpart C – *Design Requirements*)
- Proper construction (49 CFR 195 Subpart D – *Construction*, and Subpart E – *Pressure Testing*)

- Thorough and adequate inspection, testing, maintenance and repair (49 CFR 195 Subpart F – *Operation and Maintenance*, 195.402 – *Procedural manual for operations, maintenance, and emergencies*, and 195.442 – *Damage Prevention Program*)
- Operations conducted by trained and qualified workers (49 CFR 195 Subpart G – *Qualification of Pipeline Personnel*)
- Identification and mitigation of risks (195.452 - Pipeline Integrity Management)
- Coordination and preparation for emergency response (195.402 – *Procedural manual for operations, maintenance, and emergencies*, 195.403 – *Emergency Response Training*)

In addition to the provisions outlined above, many industry standards are incorporated by reference into 49 CFR Part 195, and are therefore regulatory requirements. These standards provide specifications for materials, fabrication, construction, pipe transportation, and corroded pipe analysis, which contribute to the safety of the pipeline system, and will be used in the design, operation, and maintenance of the proposed pipeline.

4.1 High Consequence Areas and Integrity Management

In accordance with the federal requirement under 49 CFR 195.452 Pipeline Integrity Management in High Consequence Areas (HCAs), Denbury will add the proposed 16-inch CO₂ pipeline to its established plan titled *CO₂ Integrity Management Program*. Denbury's integrity management plan meets 49 CFR 195.452 and establishes methodology for identifying HCAs, risk assessment of individual line segments, integrity assessment intervals, approved methods of assessment, criteria for prioritizing and repairing anomalies found during assessments, and documentation of all activities related to integrity management.

Part 195 has established pipeline integrity management regulations for pipelines in High Consequence Areas. High Consequence Area (HCA) means:

- (1) A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists;
- (2) 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;
- (3) Other populated area, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as and incorporated or unincorporated city, town, village, or other designated residential or commercial area;
- (4) An unusually sensitive area, as defined in section 195.6.

These populated and sensitive areas are published by PHMSA and used in the HCA identification process required of each natural gas and hazardous liquid pipeline operator.

4.2 Affected HCA Identification

The affected HCAs, as defined above, have been identified using data released by PHMSA and CO₂ dispersion modeling to determine the extent of possible impacts due to a pipeline release. Denbury contracted with American Innovations to perform the dispersion analysis utilizing a Det Norske Veritas proprietary software called Process Hazard Analysis Software Tool (PHA_{ST}) Version 6.6. PHAST is a fully integrated software package that allows detailed hazard assessment of toxic and flammable substances.

The dispersion modeling objective is to determine the worst case dispersion distance for the anticipated maximum pipeline flow rate and pressure. This information is used in developing safety response plans and compliance with integrity management requirements.

4.2.1 Risk Analysis Assumptions

The PHAST software considered the following in determining dispersion distances from a potential release:

- Full pipeline break or guillotine rupture, which is considered a worst case release
- 16 inch pipe diameter
- 0.375 minimum pipe wall thickness
- CO2 temperature is 110F; density is 1.842 kg/m³.
- The CO2 concentration is normalized to 100%.
- The height for concentration output is 1m (3.281 ft)
- Pipe lengths - lengths between isolation valves and quantity of material between eight (8) isolation valves
- Analysis of releases at the pipeline beginning, 25%, midpoint, 75%, and end point.
- Time to isolate flow into the pipeline and the release location is 15 minutes.
- Maximum pipeline operating pressure – 2,360 psig for a blocked discharge condition.
- Dispersion distance represents extent of 40,000 ppm concentration of CO2.
- Average meteorological conditions obtained from the National Oceanic and Atmospheric Administration (NOAA) database for the City of Lake Charles, Louisiana
 - Low temperature (41.2F) with 8.3 mph average wind speed (LTAW)
 - High temperature (91.3F) with 8.3 mph average wind speed (HTAW)

A rupture can happen at any point along the pipeline. The location of a rupture relative to the source affects the dispersion distance due to the volumes of CO2 contributed both upstream from the source and downstream of a rupture site from the pipeline itself. If a rupture is at the beginning of the pipeline then the mass available is the upstream pump rate and the inventory with the pipe from the downstream side. If the release is in the middle of the pipeline, there is an equal amount of product inventory available from the upstream and downstream ends, which may or may not result in the worst case. A pipeline rupture at the end of the pipe section has the maximum product available, but the pressure at this point will typically be lower compared to the upstream end of the pipeline. To determine which break point along the pipeline gives the worst-case scenario (maximum dispersion distance), different break point distances from the source were used in combination with other parameters.

The response time is the time to detect and isolate the pipeline when a rupture occurs. Isolation of the pipeline can be with a check valve, manually operated valve or a remotely operated valve.

When a CO2 pipeline rupture occurs, the largest dispersion distance is established within moments of initiation of the rupture when the pressure is greatest and the mass flow rate of CO2 into the rupture site is highest.

Calculated dispersion distances are applied equally to both sides of the line, assuming wind direction will push the CO2 plume to one side of the pipeline or the other and create a dispersion corridor or buffer following the centerline of the pipeline.

For CO2, 40,000 ppm (0.04 fraction) is the concentration that has been established as the Immediately Dangerous to Life and Health (IDLH) concentration for CO2 published by the National Institute for Occupational Health and Safety (NIOSH). This value was selected based on the ability for someone exposed to this concentration to: 1) Escape without loss of life or immediate or delayed irreversible health effects. (Per NIOSH, 30 minutes is considered the maximum time for escape without supplied air); and 2) prevention of severe eye or respiratory irritation or other reactions that would hinder escape.

4.2.2 Risk Analysis Results

The point release from the guillotine failure at a 50% break distance, modeled to a CO2 concentration of 40,000 ppm, had a distance higher than the other break point scenario results. This pipeline segment was then modeled at two (2) different meteorological conditions based on pipeline location to quantify the effects of wind speed on dispersion of the CO2. It was found that the high temperature with average wind speed had the largest distance to a CO2 concentration of 40,000 ppm. (Refer to Table 2 below).

The results of the analysis indicate a maximum dispersion distance of 925 feet for IDLH conditions occurs near the midpoint of the pipeline under the high temperature average wind condition (refer to Table 2 below). The minimum dispersion distance is 707 ft under low temperature average wind condition near the end point of the line. The distance of 925 feet was selected as the worst case and utilized to establish a possible exposure footprint for the entire length of the pipeline lateral and subsequently to determine the segments of the pipeline that have potential to affect HCAs.

Table 2: Meteorological Conditions - Exposure Distance

Pipeline Component	Break Point	Break Distance (feet)	HTAW (40,000 ppm Exposure Distance)	LTAW (40,000 ppm Exposure Distance)
16" Lake Charles Line	Begin	20	781	750
16" Lake Charles Line	25%	15,668	872	836
16" Lake Charles Line	50%	31,336	925	886
16" Lake Charles Line	75%	47,004	837	802
16" Lake Charles Line	End	62,673	735	707

Due to the high mass flow rate at the time of rupture, the vapor cloud travels the maximum distance within 7.3 seconds as shown in Figure 2 *CO2 Concentration vs. Maximum Plume Distance and Time*. The mass expelled from the rupture site will continue to add to the vapor cloud until the valves are completely shut, but this additional mass will not increase the vapor cloud distance due to the decreased pressure in the pipeline. Valve closure speeds and response times have little effect in reducing maximum distance; however, closure times do directly limit the duration of the public exposure and the amount of CO2 volume released to the rupture site.

Figure 1: Time vs. Mass Flow Rate and Expelled Mass

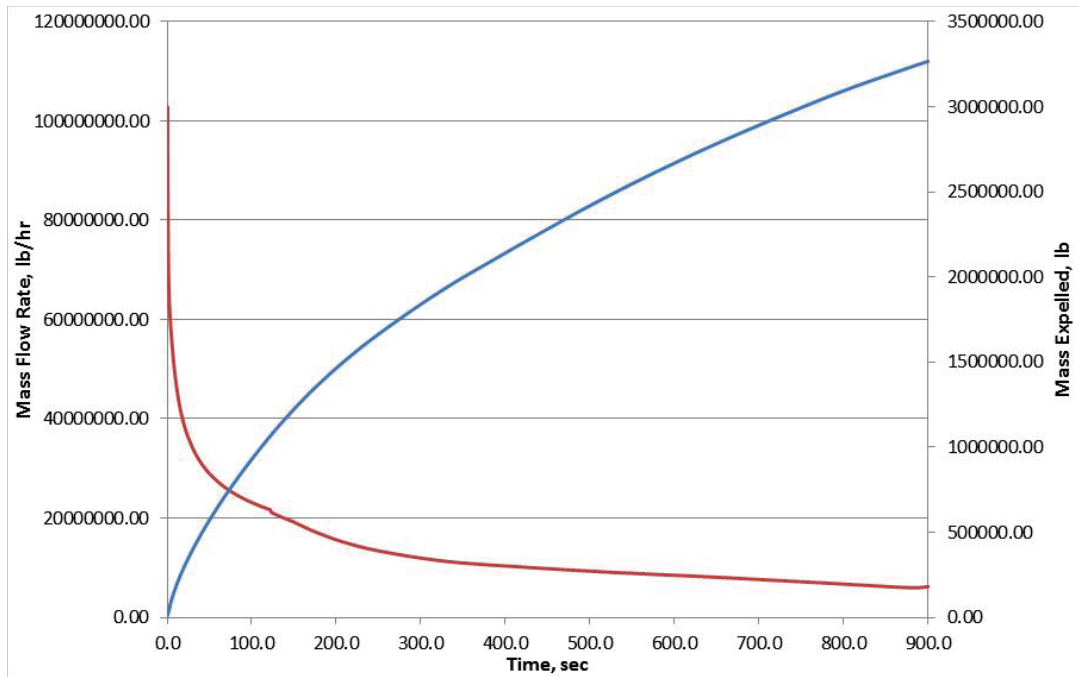
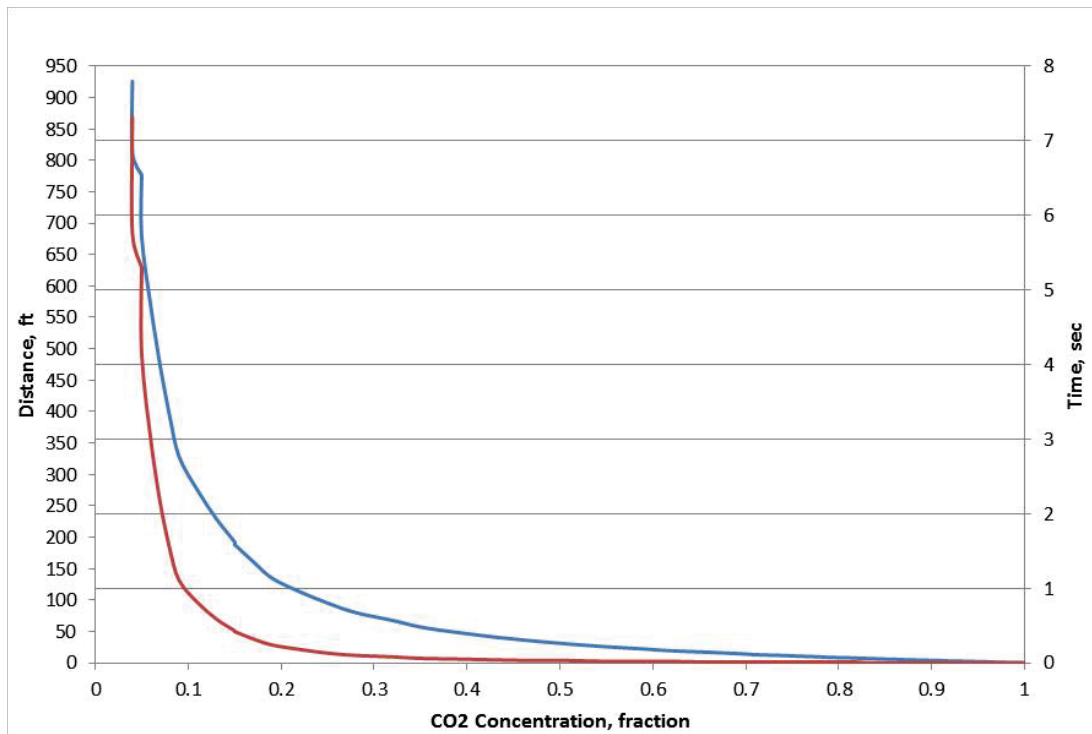


Figure 2: CO2 Concentration vs. Maximum Plume Distance and Time



4.2.3 HCA Identification

Using a 925 foot worst case dispersion corridor, the HCAs identified for the 16-inch line highly populated areas to the north and west of the pipeline near Interstate Highway 10. Approximately 2.26 miles of the route have potential to affect portions of this highly populated area. The remainder of the route is predominantly rural and not identified as an HCA by the US Department of Transportation, which consults recent census data to establish HCA footprints. A release of CO₂ can affect other areas outside of officially designated HCAs, and these are identified and addressed using mitigation measures discussed below.

4.3 Risk Mitigation Measures

The design and construction of the Denbury CO₂ pipeline lateral include the following elements to mitigate risks to the pipeline and surrounding HCA's.

- Selection of the pipeline route to minimize contact with HCA's where possible. Much of the route follows established utility corridors and traverses large undeveloped areas.
- Installing isolation valves on either side of navigable waterways >100ft in width. Waterways meeting this criterion along the pipeline route include Bayou D'Inde, the Houston River, and a Sabine River Diversion Canal. The longest section of pipeline between isolation valves is approximately 4 miles.
- Installing motor operators on strategic valves to facilitate remote closure and faster response time, typically 1-3 minutes after initiation of a closure command. Denbury operations personnel will also be located within approximately 15 minutes travel time to each valve on the pipeline.
- Hydrostatically pressure testing of all pipe and fittings in the pipeline to 125% of the maximum operating pressure. The predicted test pressure will be 2,950 psig based on the current pipeline design.
- Installing heavier wall thickness and abrasion-resistant coated pipe for all horizontal directionally drilled (HDD) installations. Pipe installed in HDDs will be designed with a 0.6 design factor, meaning that the maximum operating pressure of this pipe will be less than 60% of the pipe's specified minimum yield strength. The remainder of the pipeline will use a 0.72 design factor, irrespective of location designation.
- Incorporating inspection tool launchers and receivers into the design to allow for "smart pigs" to be run in the pipeline. Smart pigs traverse the entire length of the pipeline and record the condition of the pipe wall.
- Running a caliper or deformation inspection tool after all pipeline construction is complete to check for and allow for removal of any dents or out-of-round pipe.
- Selecting pipe steel with high impact properties to help resist outside force damage and high toughness to mitigate potential risk of ductile fracture of the pipe.
- Installing and maintaining pipe coatings and cathodic protection in accordance with DOT 49 CFR195 regulations. Pipe coatings will include 14-16 mils of fusion bond epoxy plus an additional 40 mils of abrasion-resistant coating like Powercrete for bored or horizontally drilled sections. Cathodic protection will include an industry-standard application of a low voltage charge to the pipeline to counter the positive ions created by the corrosion process.
- Burying all pipe with a minimum of 3 feet of cover or at least 4 feet of cover for any locations where the pipe is within 50 feet of a residence or business. There are currently less than 10 residences or businesses within 50 feet of the pipeline rights of way. The pipeline will be buried with at least 4 feet of cover adjacent to these structures.
- Establishing and maintaining liaison with appropriate fire, police, and public officials to

coordinate mutual assistance in responding to emergencies. The operator will also establish and maintain a continuing public awareness program in accordance with DOT 49 CFR 195 regulations to enable emergency response officials, the public, government officials, and those engaged in excavation activities to recognize a pipeline emergency and report it to appropriate public officials.

- Incorporating the pipeline and valves into a remote monitoring and control system.

5.0 CONSTRUCTION AND OPERATING MITIGATION MEASURES

The hazardous liquids pipeline industry, in general, has an excellent record of public safety. Pipeline system design, construction, operation, and maintenance follow strict industry practices, standards, and regulations to ensure public safety and reliability and to minimize the possibilities and effects of system failure. In the event of an incident, emergency response and contingency plans provide for a response to each of these circumstances. Prevention and mitigation measures for both the construction and operations phase of the Denbury Lake Charles lateral are discussed below.

5.1 Construction Phase

The pipeline will be constructed, operated and maintained in accordance with applicable Federal, state and local laws and regulations including but not limited to the DOT regulations in 49 CFR Part 195. In addition, construction specifications developed for installation of the pipeline will incorporate the requirements of all construction permits and Denbury engineering specifications, as well as project-specific plans and procedures for unique construction techniques.

Denbury will maintain an established safety program designed to minimize incidents and lost time injuries, and to protect the public near the Pipeline. Denbury will conduct group safety training sessions for inspection crews and construction contractor personnel before construction and each morning before construction activities begin. The construction contractor will also be required to have a safety representative onsite during construction. All personnel working on the right-of-way (ROW) during construction or operation and maintenance activities must at a minimum wear hard hats, safety glasses, and steel-toed shoes. Denbury requires that construction contractors perform all construction activities in a safe manner, including the operation of all construction equipment, all labor activities, and complying with the Occupational Safety and Health Administration's (OSHA's) excavation safety standards.

The Denbury Lake Charles lateral will be constructed of carbon steel manufactured in accordance with American Petroleum Institute (API) 5L, Grade X70, PSL 2 specifications, with an electric resistance welded (ERW) longitudinal weld seam. All pipe and appurtenances installed below grade will be coated with fusion-bonded epoxy or an equivalent protective coating, and painted with an industrial epoxy paint system for above grade installation. Buried pipeline joints will be coated with field-applied epoxy coatings. An impressed current cathodic protection system will be installed to further protect the integrity of the pipeline.

The proposed pipeline will be buried a minimum depth of 3 feet in all areas except at stream crossings where the burial depth will be at least 5 feet or greater under the stream/canal/river bottom (specific permit requirements will dictate exact burial depth for some crossings). Warning signs will be placed at road crossings and at other strategic spots along the pipeline route that will include identification and ownership information, including emergency contact telephone numbers.

The end point inspection tool launcher/receiver traps and intermediate valve stations will be located within security-fenced areas to prevent unauthorized access to the facilities. Buildings will be made of non-combustible materials. Electrical equipment and wiring will be installed in conformance with applicable sections of the National Electric Code, National Fire Protection Association (NFPA)-70.

The pipeline will be hydrostatically tested to prove its structural integrity before CO₂ is introduced into the line and it commences operation. Testing will be performed and documented in accordance with 49 CFR Part 195.

Denbury will take further safety precautions regarding foreign utility lines that may be crossed during construction. Denbury will send letters to the owners of all known, reported, or otherwise documented lines within the proposed work areas along with drawings showing the location of the owners' respective lines. In the letters, Denbury will request a written response to the following inquiries:

- Size, type, and pressure
- Verification of the location and depth of cover
- ROW width
- Information concerning other pipelines immediately adjacent to or intersecting the new pipeline that were identified
- Special construction requirements
- Names, addresses, telephone numbers, and lead time of personnel to contact before construction begins

During construction, the contractor will complete the One Call notification to allow operators of foreign pipelines and utilities to probe and mark each line. Each foreign utility line will be carefully exposed before trenching.

Before construction, Denbury will notify all appropriate local officials and agencies concerning the schedule of upcoming construction activities. Where necessary, arrangements for detours and warning signs will be made for roads that will be impacted.

5.2 Operations Phase

Denbury maintains an operations and maintenance manual containing written procedures for normal operations and maintenance and abnormal operations and emergencies in accordance with DOT 49 CFR 195 regulations. This manual includes requirements for preventive maintenance and patrols of facilities, as well as procedures to be followed in the event of an accident or natural catastrophe. This manual is made available to all affected operations personnel.

Periodic training sessions and review of operating procedures and emergency procedures will be conducted for affected operations employees. This training will include the safe operation of all pipeline system equipment, hazardous material handling procedures, public liaison programs, emergency response actions and coordination, and general operating procedures.

Measures will be implemented to protect the public and exclude unauthorized persons from hazardous areas along the pipeline. All above ground facilities including block valves, scraper traps and delivery points will have perimeter chain link fencing with multiple-strand barbed wire

at the top. Valves and access gates will be locked at unmanned locations. Signage at facilities will include statements such as "Authorized Personnel Only". On the right-of-way, pipeline warning signs complying with DOT regulations will be placed at all road, railroad and waterway crossings and at other locations of public access. Besides warning of the pipeline's location, the signs will direct the public to call the Operations Control Center and the local one-call notification center at least 48 hours before commencing any excavation near the pipeline. Additionally, aerial patrols will give immediate phone notification to dispatch operations personnel of any apparent activity by the public near the pipeline that could be an endangerment to people and the pipeline.

Standard procedures will be implemented for temporary marking of the pipeline for third party contractors and utilities, and for obtaining adequate marking and location information of foreign lines and utilities prior to commencing maintenance work. Standard procedures will be implemented for maintenance activities such as lock-out / tag-out procedures, checking for low-oxygen atmospheres when the pipeline is opened, procedures for excavating pipelines and utilities, traffic control, and procedures that will ensure compliance with pertinent OSHA regulations.

5.3 Right-of-Way Inspections

Regularly scheduled aerial patrols of all Lake Charles lateral facilities will be performed along with scheduled preventive maintenance. Periodic vehicle patrol will also be used. Any unusual situation or condition will be reported and investigated immediately.

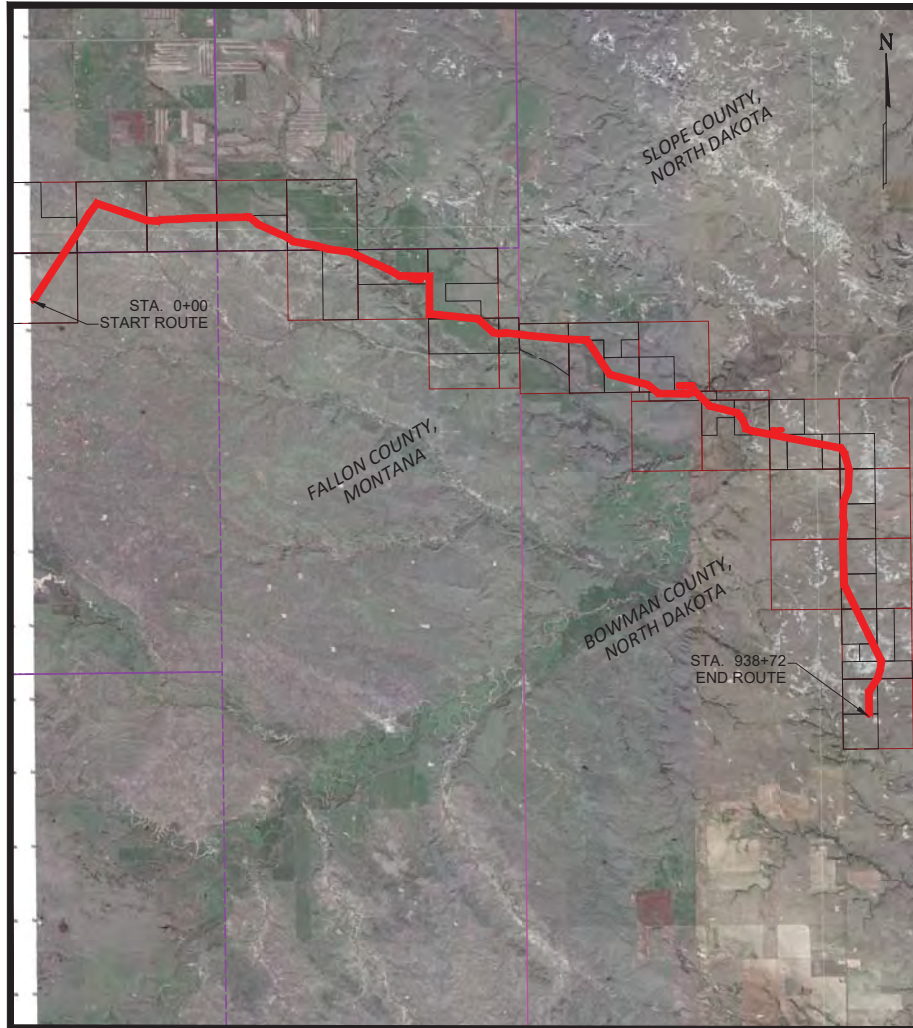
Denbury is also a member of the local Louisiana "One Call" System pre-excavation notification organization. Through this system, contractors provide notification to a central agency of proposed excavations, which in turn notifies the operator of the excavation locations. If facilities are located in the area of proposed contractor activity, they will be marked in the field, and a representative of the operator will be present during excavation to ensure that the facility is not compromised.

5.4 Monitoring and Control

An operations control center will monitor system pressures, flows, and customer deliveries. Further, the control center is manned 24 hours per day, 365 days per year. The operator will have remote operation control of specific mainline valves.

A Supervisory Control and Data Acquisition (SCADA) system, in the operations control center, will provide for pipeline control and monitoring at all times. Remote Terminal Units (RTU's) for the SCADA system will be present at the end point stations and specific block valves along the system. If system pressures fall outside a predetermined range, an alarm will be activated and notice will be transmitted to the operations control center. The alarm will include notice if pressures at a station are not within an acceptable range. The operator will take corrective action and/or dispatch personnel to investigate the situation. Denbury personnel will provide quick response to emergencies and direct safety operations as necessary.

DENBURY RESOURCES INC.
PROPOSED 12" PIPELINE
FALLON COUNTY, MONTANA; SLOPE COUNTY, NORTH DAKOTA;
BOWMAN COUNTY, NORTH DAKOTA



ALIGNMENT SHEET INDEX
43-063-LA-CHSULAT-220-0020-1
43-063-LA-CHSULAT-220-0021-2
43-063-LA-CHSULAT-220-0022-3
43-063-LA-CHSULAT-220-0023-4
43-063-LA-CHSULAT-220-0024-5
43-063-LA-CHSULAT-220-0025-6
43-063-LA-CHSULAT-220-0026-7
43-063-LA-CHSULAT-220-0027-8
43-063-LA-CHSULAT-220-0028-9
43-063-LA-CHSULAT-220-0029-10
43-063-LA-CHSULAT-220-0030-11
43-063-LA-CHSULAT-220-0031-12
43-063-LA-CHSULAT-220-0032-13
43-063-LA-CHSULAT-220-0033-14
43-063-LA-CHSULAT-220-0034-15
43-063-LA-CHSULAT-220-0035-16
43-063-LA-CHSULAT-220-0036-17
43-063-LA-CHSULAT-220-0037-18
43-063-LA-CHSULAT-220-0038-19
43-063-LA-CHSULAT-220-0039-20

UTILITY STATEMENT:
 The utility locations shown on this plan have been based on field survey information and One-Call records. The surveyor makes no guarantee that the underground utilities shown comprise all such utilities in the area, either in service or abandoned. The surveyor further does not warrant that the information shown on this plan is complete or accurate, although information available. The surveyor has not physically located the underground utilities.



350 INTERLOCKEN BLVD.
 BROOMFIELD, CO 80021



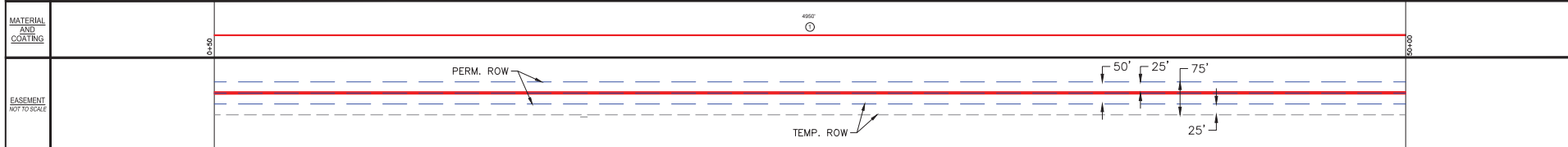
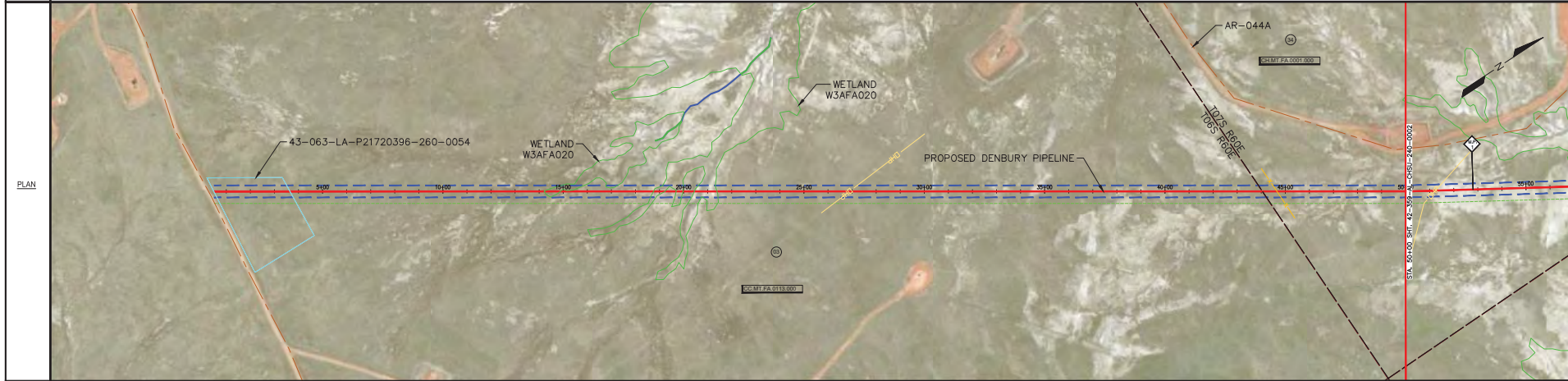
DENBURY RESOURCES INC.
 10000 W. STATE ST. SUITE 100
 PLANO, TX 75024
 TEL (972) 673-2000



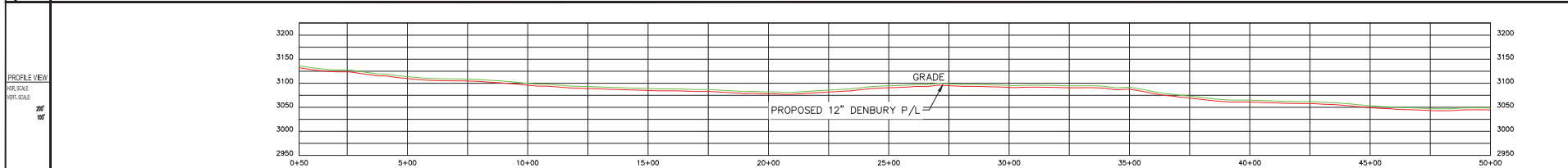
REVISION: A
JOB NUMBER: 61495
SHEET TITLE: COVER SHEET
DATE: 11/20/18
DWG. NUM: 43-063-LA-CHSULAT-220-0020-1

OWNERSHIP	0+50	CCMT FA 0113 000 MIRSCHTEN 200.00 FEET	4+00	CHMT FA 0001 000 KEVIN J BRAUN AND MARILL 30.00 FEET	50+00
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PIPELINE STATIONING	0+50 BEGIN STA.	14+21 WETLAND LIMITS 14+88 WETLAND LIMITS	18+75 WETLAND LIMITS 19+22 WETLAND LIMITS 19+88 WETLAND LIMITS 20+45 WETLAND LIMITS	21+30 WETLAND LIMITS	24+88 OVERHEAD POWER	30+75 OVERHEAD POWER	44+00 SEC. 02 44+00 PROPERTY LINE 44+00 FENCE	50+00
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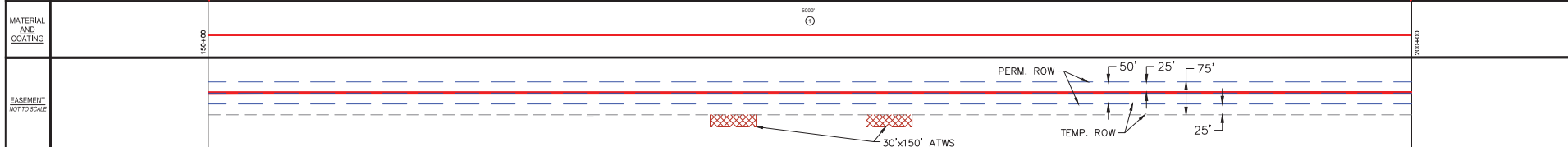
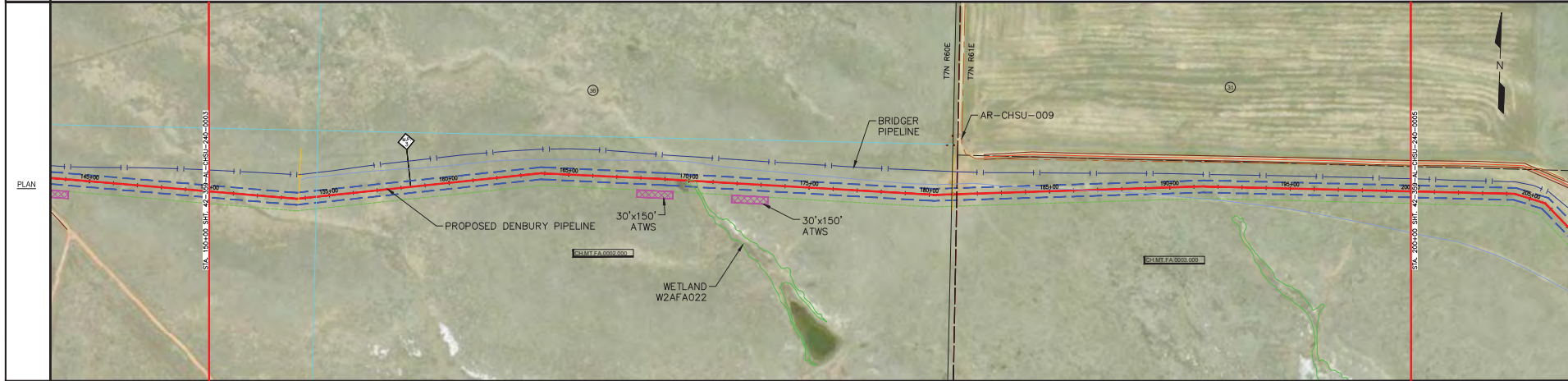


ENVIRONMENTAL	W3AFA020	W3AFA020
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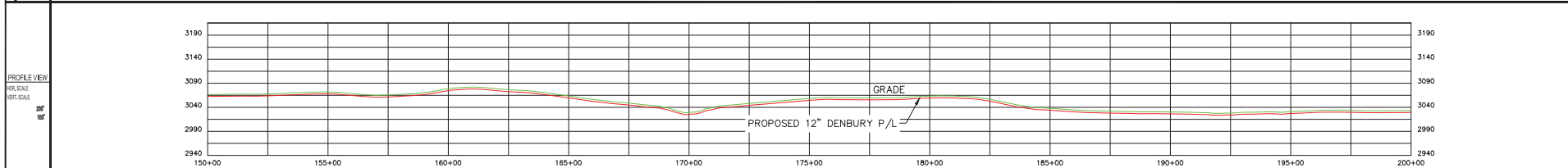


LEGEND PROPOSED PIPELINE: ——— EXISTING PIPELINE: - - - - PERMANENT EASEMENT: ——— TEMPORARY EASEMENT: - - - - CL. ROAD: ——— ACCESS ROAD: - - - - BANKLINE: ——— CS 2001: ——— SECTION LINE: ——— OH POWER LINE: ——— INTURN SPACE: ——— HEAVY WALL PIPE: ——— WETLAND LIMITS: ——— LIND. ROAD: ———	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED.	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>AM. NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>4.950'</td> <td>12.75" O.D. x 0.460" WT-GR X 709AL 14 - 18 MILS FBE Line pipe</td> </tr> <tr> <td>2</td> <td>0'</td> <td>12.75" O.D. x 0.562" WT-GR X 709AL 14 - 18 MILS FBE w/30-40 MILS ARD</td> </tr> </tbody> </table>	AM. NO.	QTY.	DESCRIPTION	1	4.950'	12.75" O.D. x 0.460" WT-GR X 709AL 14 - 18 MILS FBE Line pipe	2	0'	12.75" O.D. x 0.562" WT-GR X 709AL 14 - 18 MILS FBE w/30-40 MILS ARD	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	encompass 350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021	Denbury
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NO.	DATE	DESCRIPTION																		
A	11/19/18	ISSUE FOR REVIEW																		
LEGEND (CONT.) HED POINT: ● BORE SAMPLE LOCATION: ⊙ SECTION NUMBER: ⊕ CRACK ARRESTOR: ⊠ CONCRETE WEIGHTS: ⊞ HED/BORE AREA: ⊕ ADDITIONAL TEMP WORKSPACE (STRS): ⊞	REVISIONS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> <th>SCALE</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>11/14/18</td> <td></td> <td>200'</td> </tr> <tr> <td>2</td> <td>11/18/18</td> <td></td> <td></td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	SCALE	1	11/14/18		200'	2	11/18/18			PROPOSED 12" PIPELINE 0+50 TO 50+00 T6N R60E & T7N R60E FALLON COUNTY, MONTANA	REV. A					
NO.	DATE	DESCRIPTION	SCALE																	
1	11/14/18		200'																	
2	11/18/18																			

OWNERSHIP	150+00	(CH MT FA 0002 000) STATE OF MONTANA 188-73 RD005	181+14	(CH MT FA 0003 000) CHRISTOPHER D JAMES CRAWFORD 174-20 RD005	200+00
PIPELINE STATIONING	150+00	150+00 P.L. - 150+727' L.L. 153+72' P.O.C.	163+88 P.L. - 164+151' E.L.	169+20 WETLAND LIMITS 169+20 WETLAND LIMITS 163+72' P.O.C.	180+16 P.L. - 180+507' L.L. 180+47' P.O.C. 181+15' E.L. - 181+15' E.L. BY LINE 181+15' E.L. - 181+15' E.L. BY LINE 181+15' E.L. - 181+15' E.L. BY LINE



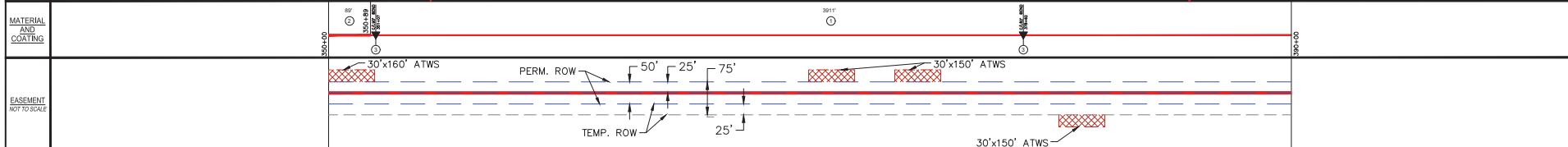
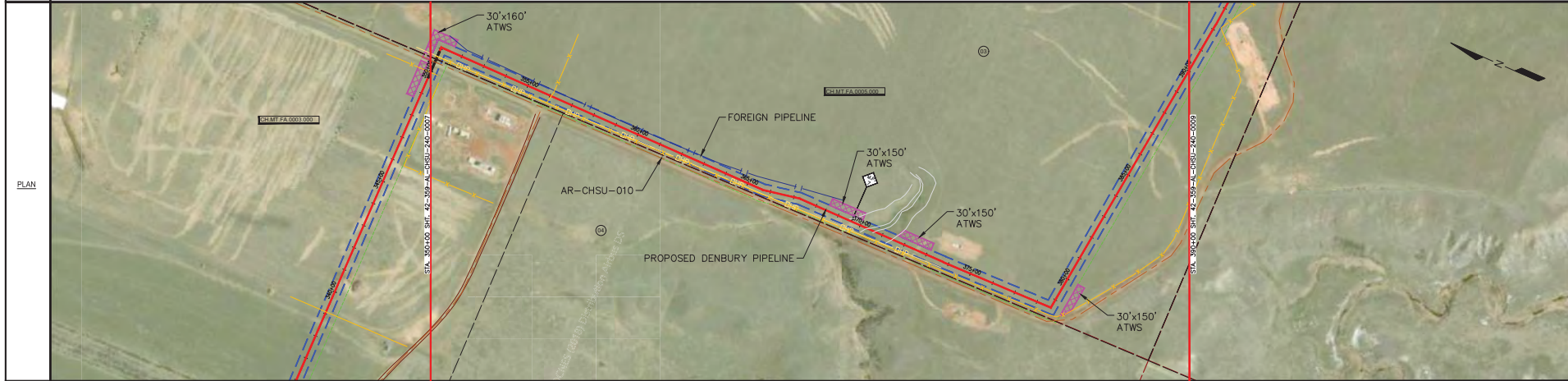
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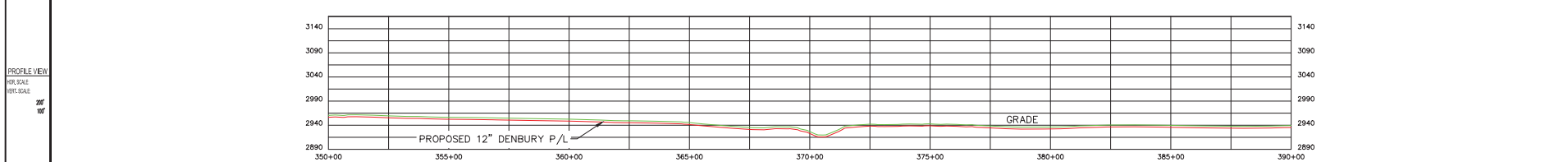
LEGEND PROPOSED PIPELINE EXISTING PIPELINE PERMANENT EASEMENT TEMPORARY EASEMENT CL ROAD ACCESS ROAD BANKLINE CS 300' SECTION LINE PROPERTY LINE OH POWER LINE WETLAND SHORE HEAVY WALL PIPE WETLAND LIMITS UMG NODE	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>5,000'</td> <td>12.75" O.D. x 0.460" WT-GR X 70WAL 14 - 18 MILS FBE Line Pipe</td> </tr> <tr> <td>2</td> <td>0'</td> <td>12.75" O.D. x 0.562" WT-GR X 70WAL 14 - 18 MILS FBE w/30-40 MILS ARD</td> </tr> </tbody> </table>	NO.	QTY.	DESCRIPTION	1	5,000'	12.75" O.D. x 0.460" WT-GR X 70WAL 14 - 18 MILS FBE Line Pipe	2	0'	12.75" O.D. x 0.562" WT-GR X 70WAL 14 - 18 MILS FBE w/30-40 MILS ARD	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	encompass 350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021	Denbury	SCALE 200' DRAWN BY DATE 11/14/18 CHECKED DATE 11/18/18 APP'D DATE PLS JOB NO. PLS/PLANS 61495 CLIENT FILE NO. PLS FILE NO.	PROPOSED 12" PIPELINE 150+00 TO 200+00 17N R60E & 17N R61E FALLON COUNTY, MONTANA	REV. A
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A	11/19/18	ISSUE FOR REVIEW																					
LEGEND (CONT.) HED POINT BORE SAMPLE LOCATION SECTION NUMBER CRACK ARRESTOR CONCRETE WEIGHS HED/BORE AREA ADDITIONAL TEMP WORKSPACE (ATWS) CONCRETE COATING																							

OWNERSHIP	CHMT FA 0033.000 CHRISTOPHER G AND JAMIE CRAWFORD 221 RIGGS	CHMT FA 0035.000 EUGENE P & FRANCES I BONASALLA 239-21 RIGGS
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PIPELINE STATIONING	366+06 FENCE 366+46 (R-CHSU-010) 366+89 (R-CHSU-010) 367+27 (L-CHSU-010) 367+27 (L-CHSU-010) 370+45 (R-CHSU-010) 370+45 (R-CHSU-010) 371+45 (R-CHSU-010) 373+78 (L-CHSU-010) 378+62 (L-CHSU-010)
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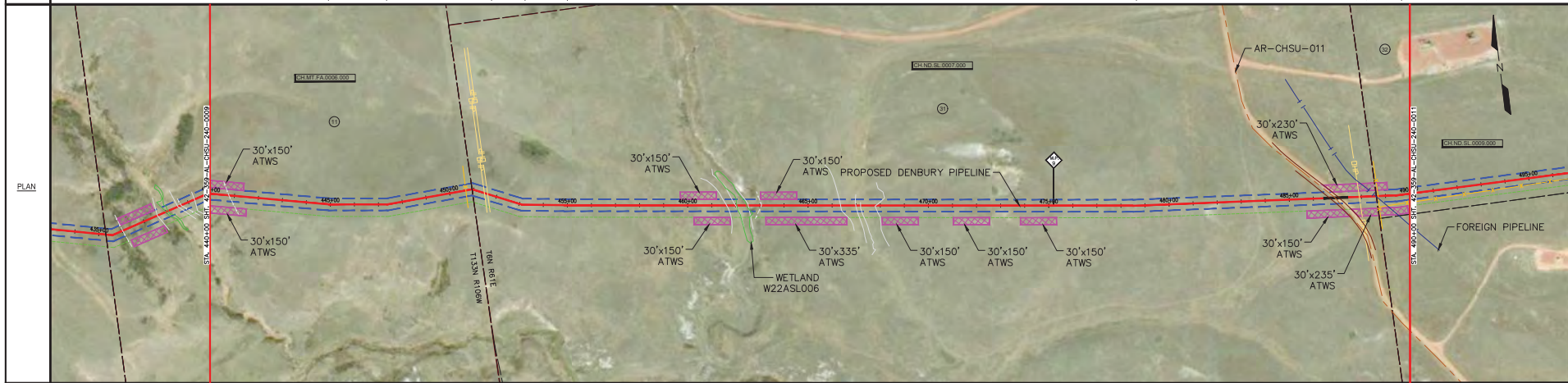
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 LIFE: NONE
 ENVIRONMENTAL: NONE



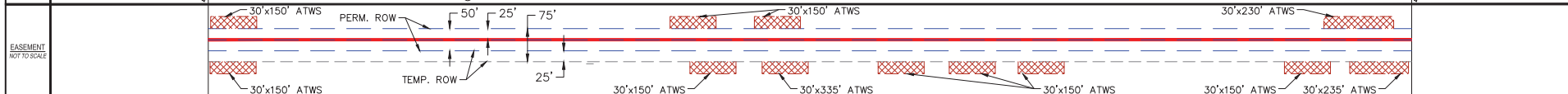
LEGEND PROPOSED PIPELINE: Solid red line EXISTING PIPELINE: Dashed red line PERMANENT EASEMENT: Blue hatched area TEMPORARY EASEMENT: Yellow hatched area ACCESS ROAD: Dashed black line BANKLINE: Dashed black line CS 2001: Dashed black line SECTION LINE: Dashed black line PROPERTY LINE: Dashed black line OH POWER LINE: Dashed black line WELAND: Dashed black line HEAVY WALL PIPE: Dashed black line WELAND LIMITS: Dashed black line LIND ROAD: Dashed black line HED POINT: Circle with cross BORE SAMPLE LOCATION: Circle with dot SECTION NUMBER: Circle with number CRACK ARRESTOR: Square with cross CONCRETE WEIGHTS: Square with cross HED/BORE AREA: Square with cross ADDITIONAL TEMP WORKSPACE (ATWS): Square with cross CONCRETE COATING: Square with cross	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED.	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>LINE NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>3211'</td> <td>12.75" O.D. x 0.465" WT-GR X 70MIL 14 - 18 MILS FBE LINE PIPE</td> </tr> <tr> <td>2</td> <td>89'</td> <td>12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FBE W/30-40 MILS ARD</td> </tr> <tr> <td>3</td> <td>2</td> <td>INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)</td> </tr> </tbody> </table>	LINE NO.	QTY.	DESCRIPTION	1	3211'	12.75" O.D. x 0.465" WT-GR X 70MIL 14 - 18 MILS FBE LINE PIPE	2	89'	12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FBE W/30-40 MILS ARD	3	2	INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	encompass 350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021	Denbury PROPOSED 12" PIPELINE 350+00 TO 390+00 T6N R61E FALLON COUNTY, MONTANA
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NO.	DATE	DESCRIPTION	SCALE																				
			200'																				

OWNERSHIP	440+00 CH.MT.FA.0006.000 DONNA K. RONNING AND DAVID L. KESSEE 65.32 ACRES	450+00 CH.ND.SL.0007.000 EUGENE BENSALLA 220.98 ACRES	480+00 CH.ND.SL.0008.000 EUGENE & FRANCIS BENSALLA 8.34 ACRES
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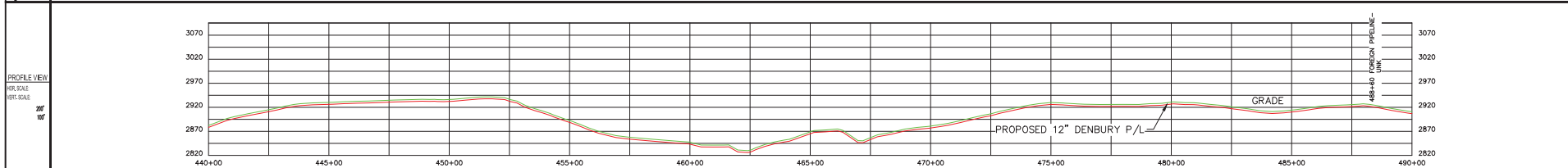
PIPELINE STATIONING	440+77 TOP OF BANK 444+00 E.P.L. - CHSU-011 447+00 E.P.L. - W22ASL006 450+00 TRUCK 450+04 PROPERTY LINE 450+05 SEC. 31 451+00 CHSU-011 451+02 OVERHEAD POWER 453+10 E.P.L. - W22ASL006 454+00 E.P.L. - CHSU-011	466+05 TOP OF BANK 467+18 TOP OF BANK 467+82 TOP OF BANK	478+50 E.P.L. - W22ASL006 486+43 BEGIN BORER 486+45 END BORER 486+46 BEGIN BORER 486+48 END BORER 486+49 BEGIN BORER 486+51 END BORER 486+52 BEGIN BORER 486+54 END BORER 486+55 BEGIN BORER 486+57 END BORER 486+58 BEGIN BORER 486+60 END BORER 486+61 BEGIN BORER 486+63 END BORER 486+64 BEGIN BORER 486+66 END BORER 486+67 BEGIN BORER 486+69 END BORER 486+70 BEGIN BORER 486+72 END BORER 486+73 BEGIN BORER 486+75 END BORER 486+76 BEGIN BORER 486+78 END BORER 486+79 BEGIN BORER 486+81 END BORER 486+82 BEGIN BORER 486+84 END BORER 486+85 BEGIN BORER 486+87 END BORER 486+88 BEGIN BORER 486+90 END BORER 486+91 BEGIN BORER 486+93 END BORER 486+94 BEGIN BORER 486+96 END BORER 486+97 BEGIN BORER 486+99 END BORER 487+00 BEGIN BORER 487+02 END BORER 487+03 BEGIN BORER 487+05 END BORER 487+06 BEGIN BORER 487+08 END BORER 487+09 BEGIN BORER 487+11 END BORER 487+12 BEGIN BORER 487+14 END BORER 487+15 BEGIN BORER 487+17 END BORER 487+18 BEGIN BORER 487+20 END BORER 487+21 BEGIN BORER 487+23 END BORER 487+24 BEGIN BORER 487+26 END BORER 487+27 BEGIN BORER 487+29 END BORER 487+30 BEGIN BORER 487+32 END BORER 487+33 BEGIN BORER 487+35 END BORER 487+36 BEGIN BORER 487+38 END BORER 487+39 BEGIN BORER 487+41 END BORER 487+42 BEGIN BORER 487+44 END BORER 487+45 BEGIN BORER 487+47 END BORER 487+48 BEGIN BORER 487+50 END BORER 487+51 BEGIN BORER 487+53 END BORER 487+54 BEGIN BORER 487+56 END BORER 487+57 BEGIN BORER 487+59 END BORER 487+60 BEGIN BORER 487+62 END BORER 487+63 BEGIN BORER 487+65 END BORER 487+66 BEGIN BORER 487+68 END BORER 487+69 BEGIN BORER 487+71 END BORER 487+72 BEGIN BORER 487+74 END BORER 487+75 BEGIN BORER 487+77 END BORER 487+78 BEGIN BORER 487+80 END BORER 487+81 BEGIN BORER 487+83 END BORER 487+84 BEGIN BORER 487+86 END BORER 487+87 BEGIN BORER 487+89 END BORER 487+90 BEGIN BORER 487+92 END BORER 487+93 BEGIN BORER 487+95 END BORER 487+96 BEGIN BORER 487+98 END BORER 487+99 BEGIN BORER 488+00 END BORER
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MATERIAL AND COATING	440+00 486+43 487+43 490+00
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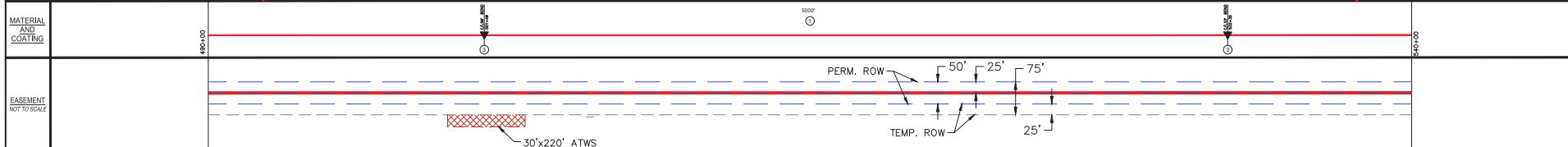
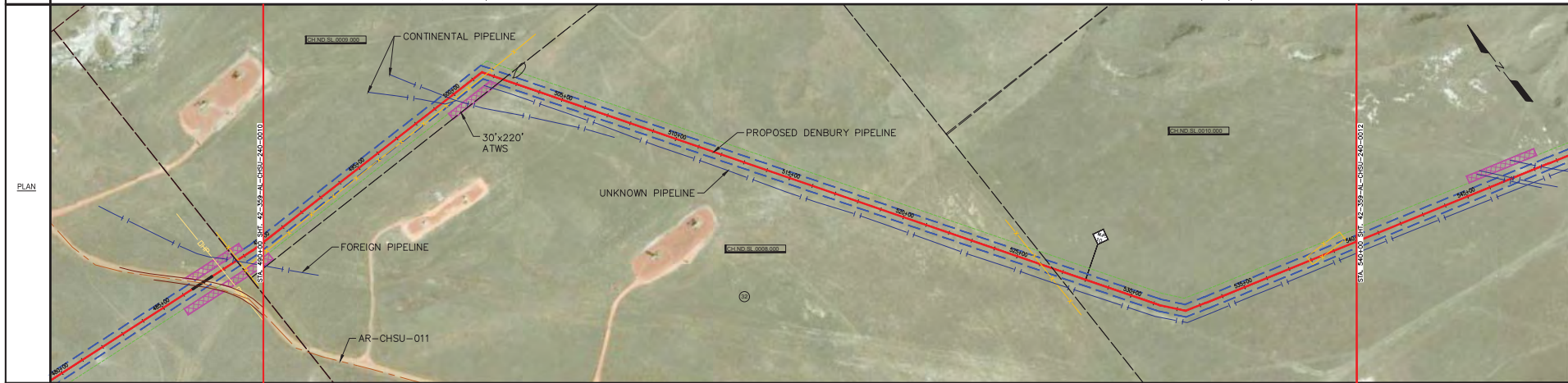
ENVIRONMENTAL	W22ASL006 WETLANDS W22ASL006
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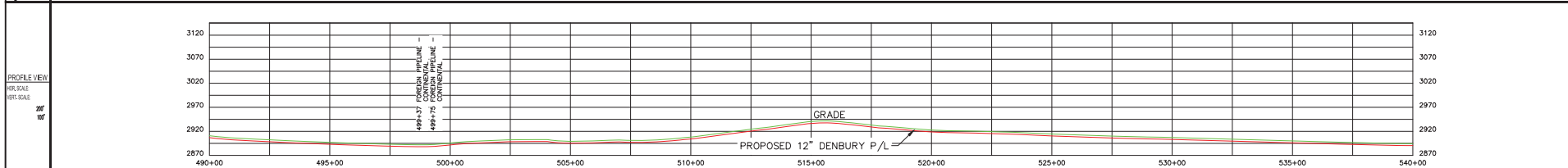
LEGEND PROPOSED PIPELINE EXISTING PIPELINE PERMANENT EASEMENT TEMPORARY EASEMENT C.L. ROAD ACCESS ROAD BANKLINE C.S. STON SECTION LINE PROPERTY LINE OH POWER LINE NATURAL SLOPE HEAVY WALL PIPE WETLAND LIMITS LAND ROAD HED POINT BORE SAMPLE LOCATION SECTION NUMBER CRACK ARRESTOR CONCRETE WEIGHS HED/BORE AREA ADDITIONAL TEMP WORKSPACE (ATWS) CONCRETE COATING	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>AM. NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>4500'</td> <td>12.75" O.D. x 0.465" WT-GR X 70MIL 14 - 18 MILS FIBRE LINE PIPE</td> </tr> <tr> <td>2</td> <td>100'</td> <td>12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FIBRE w/30-40 MILS ARD</td> </tr> <tr> <td>3</td> <td>1</td> <td>INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)</td> </tr> </tbody> </table>	AM. NO.	QTY.	DESCRIPTION	1	4500'	12.75" O.D. x 0.465" WT-GR X 70MIL 14 - 18 MILS FIBRE LINE PIPE	2	100'	12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FIBRE w/30-40 MILS ARD	3	1	INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	REVISIONS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021 Denbury SCALE 200' DRAWN/CDL DATE 11/14/18 CHKD/MLJ DATE 11/18/18 APP'D/GRE DATE PLS JOB NO. PLS/P.A.M. NO. 61495 CLIENT FILE NO. PLS FILE NO.	PROPOSED 12" PIPELINE 440+00 TO 490+00 T6N R61E & R133N R106W FALLON COUNTY, MT/SLOPE COUNTY, ND 42-063-LA-CHSULTA-220-0030-11 REC. A
		AM. NO.	QTY.	DESCRIPTION																										
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A	11/19/18	ISSUE FOR REVIEW																												
LEGEND (CONT.) 																														

OWNERSHIP	490+00	(CHND SL 0009.000) EUGENE & FRANCIS SENSALLA 75.17 ACRES	520+00	(CHND SL 0008.000) MIKE SENSALLA 146.37 ACRES	520+00	(CHND SL 0010.000) HAULEY BROTHERS LLP 81.49 ACRES	540+00
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PIPELINE STATIONINGS	490+00	499+37 FOREIGN PIPELINE - CONTINENTAL 499+75 FOREIGN PIPELINE - CONTINENTAL 501+69 E.L. & 504937' BT. 501+69 FENCE 502+40 PROPERTY LINE	520+00	520+00	520+00	528+04 FENCE 528+55 PROPERTY LINE 531522 E.L. & 806250' LT. 532235 E.L. & 329211' LT. 533128 E.L. & 101116' LT. 537+91 FENCE 538+87 FENCE	540+00
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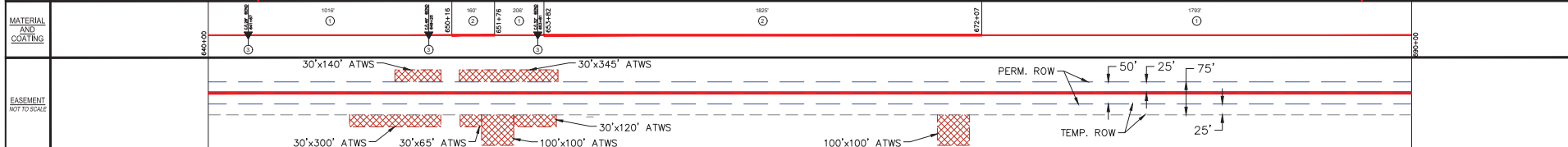
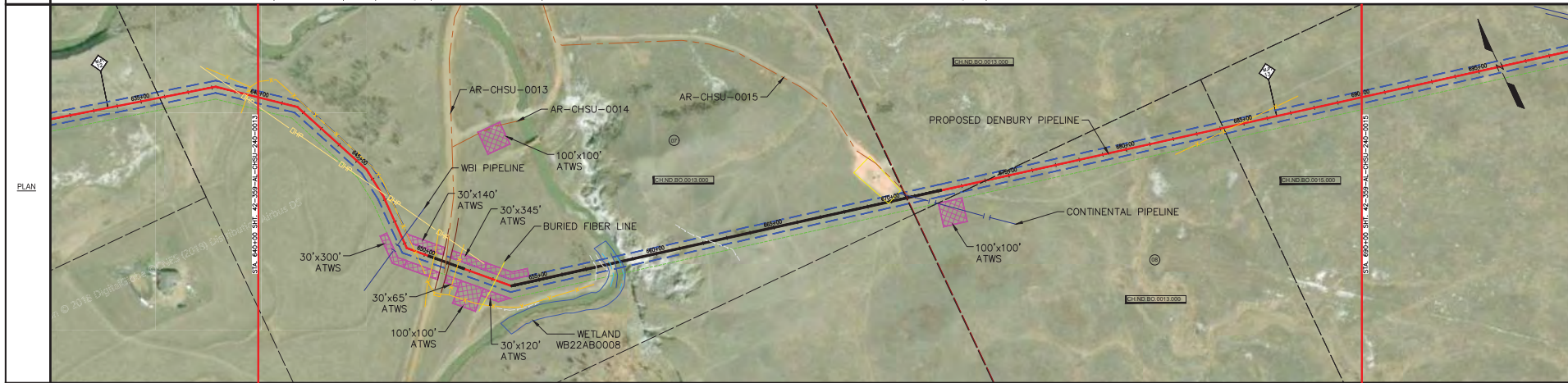
ENVIRONMENTAL	WETLANDS PERFECTION	WETLANDS PERFECTION CONTROL
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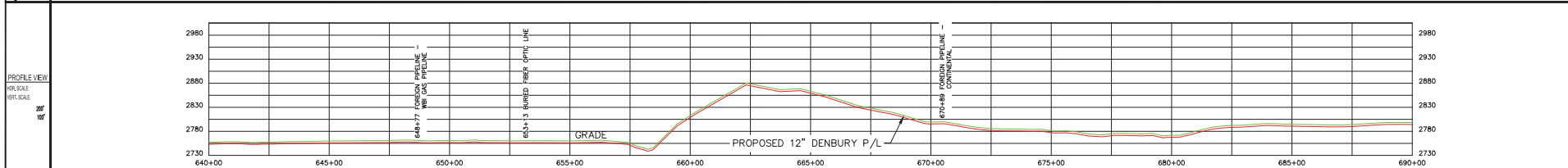
LEGEND PROPOSED PIPELINE: Solid blue line EXISTING PIPELINE: Dashed blue line PERMANENT EASEMENT: Solid red line TEMPORARY EASEMENT: Dashed red line C.L. ROAD: Solid black line ACCESS ROAD: Dashed black line BANKLINE: Solid green line C.S. STON: Solid purple line SECTION LINE: Solid yellow line PROPERTY LINE: Solid orange line OH POWER LINE: Solid brown line WETLAND SHORE: Solid light blue line HEAVY WALL PPE: Solid dark blue line WETLAND LIMITS: Dotted light blue line UMG NODE: Solid black line HED POINT: Circle with cross BORE SAMPLE LOCATION: Circle with dot SECTION NUMBER: Square with number CRACK ARRESTOR: Square with 'X' CONCRETE WEIGHTS: Square with 'X' HED/BORE AREA: Square with 'X' ADDITIONAL TEMP WORKSPACE (ATWS): Hatched area CONCRETE COATING: Square with 'X'	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED.	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>MT. NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>5,000'</td> <td>12.75" O.D. x 0.465" WT-GR X 70MIL 14 - 18 MILS FIBRE LINE 999</td> </tr> <tr> <td>2</td> <td>0'</td> <td>12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FIBRE w/30-40 MILS ARD</td> </tr> <tr> <td>3</td> <td>2</td> <td>INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)</td> </tr> </tbody> </table>	MT. NO.	QTY.	DESCRIPTION	1	5,000'	12.75" O.D. x 0.465" WT-GR X 70MIL 14 - 18 MILS FIBRE LINE 999	2	0'	12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FIBRE w/30-40 MILS ARD	3	2	INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	encompass 350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021 <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> <th>SCALE</th> </tr> </thead> <tbody> <tr> <td></td> <td></td> <td></td> <td>200'</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	SCALE				200'	 PROPOSED 12" PIPELINE 490+00 TO 540+00 T1133N R106W SLOPE COUNTY, NORTH DAKOTA 42-063-LA-CHSULAT-220-0031-12
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			200'																												
LEGEND (CONT.) CONCRETE COATING: Square with 'X'				CLIENT FILE NO. PDS FILE NO.	REV. A																										

OWNERSHIP	640+00	CH ND BO 0013 000 BRADLEY & DUFFIELD 105.68 ACROSS	670+00	CH ND BO 0013 000 BRADLEY & DUFFIELD 105.68 ACROSS	674+00	CH ND BO 0013 000 BRADLEY & DUFFIELD 61.11 ACROSS	684+13	CH ND BO 0015 000 SCOTT P BRIDGAC 30.55 ACROSS	690+00
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PIPELINE STATIONINGS	641167.01' L. - 2612300' ST.	645545.55' E.L. - 1529301' ST.	646149 OVERHEAD POWER 584828.91' L. - 735700' ST.	648177 FOREIGN PIPELINE - 549320.00' L. - 4546497' LT.	649155 FENCE LINE	650141 FENCE LINE	651176 END BORE	653113 BURIED FIBER OPTIC LINE	653142 SECOND BORE	657145 TOP OF BANK	657147 WETLAND LIMITS	657148 WETLAND LIMITS	657149 WETLAND LIMITS	658144 WETLAND LIMITS	658145 WETLAND LIMITS	662132 TOP OF BANK	669145 END BORE	670144 PROPERTY LINE	670147 END BORE	670148 WETLAND LIMITS	670149 WETLAND LIMITS	672107 END BORE	672108 WETLAND LIMITS	674105 PROPERTY LINE	684113 PROPERTY LINE	684176 FENCE
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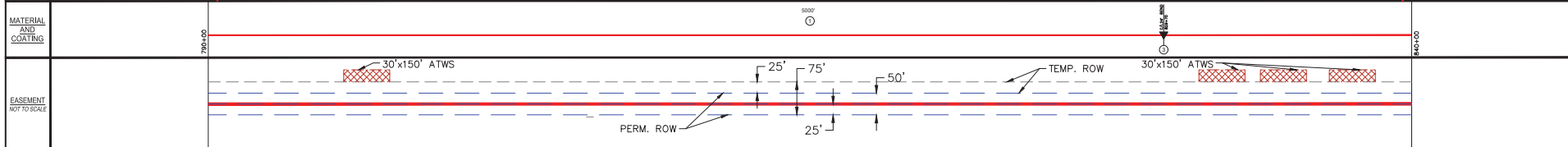
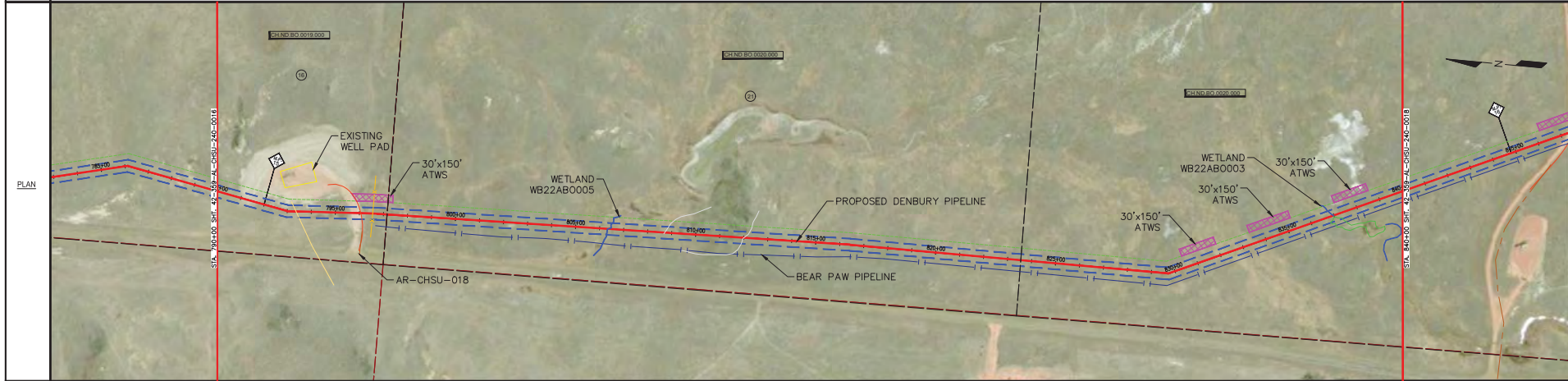


ENVIRONMENTAL	WETLAND ENCROACHMENT										
WETLAND ENCROACHMENT	WB22AB0008										

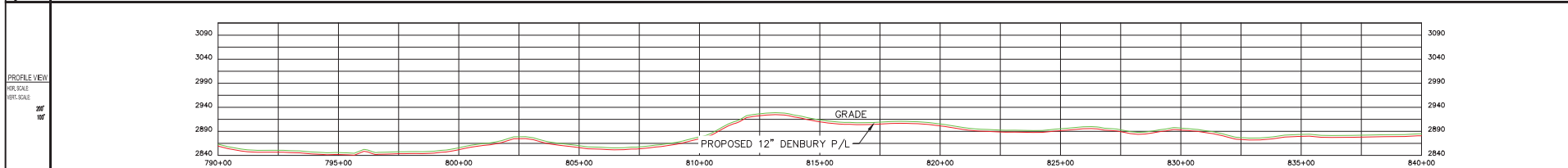


LEGEND	NOTES	MATERIAL SUMMARY		REFERENCE DRAWINGS		350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021																																						
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NO.	QTY.	DESCRIPTION																																										
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PCS FILE NO.																																												
LEGEND (CONT.)								<p>42-063-LA-CHSULAT-220-0034-15</p>																																				

OWNERSHIP	790+00	(CH ND 80 0019 000) DANIEL J & JOANNE FISCHER 43 36 ROADS	797+15	(CH ND 80 0020 000) DOUBLE S&K PLATNESS RANCH L/TM 159 98 ROADS	802+55	(CH ND 80 0020 000) DOUBLE S&K PLATNESS RANCH L/TM 99 70 ROADS	840+00
PIPELINE STATIONINGS		792458 P/L < 14'03'00" LT 793116 OVERHEAD POWER 796406 CL OF ROAD 798445 FENCE 799112 CL OF ROAD 799112 CL OF ROAD 799112 CL OF ROAD 799112 CL OF ROAD 804+33 WETLAND LIMITS 806+40 WETLAND LIMITS 808+71 TOE OF BANK 812+00 TOP OF BANK 816+00 TOP OF BANK 816+00 TOP OF BANK 816+00 TOP OF BANK 823+45 PROPERTY LINE 829+00 P/L < 24'03'00" LT 834+98 WETLAND LIMITS 836+98 WETLAND LIMITS					



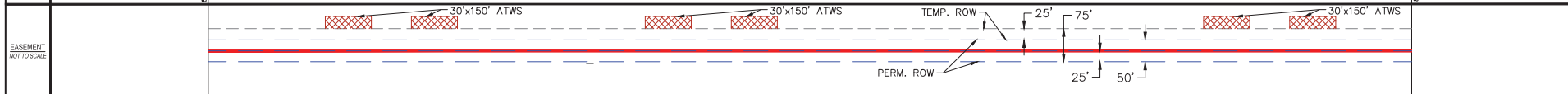
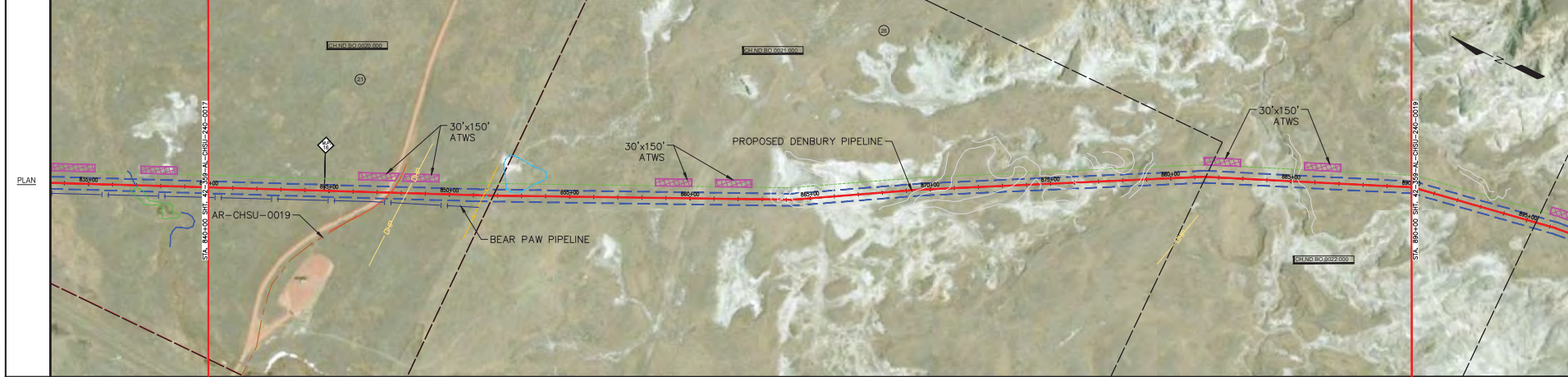
WETLANDS	WB22AB0005	WB22AB0003
ENVIRONMENTAL		



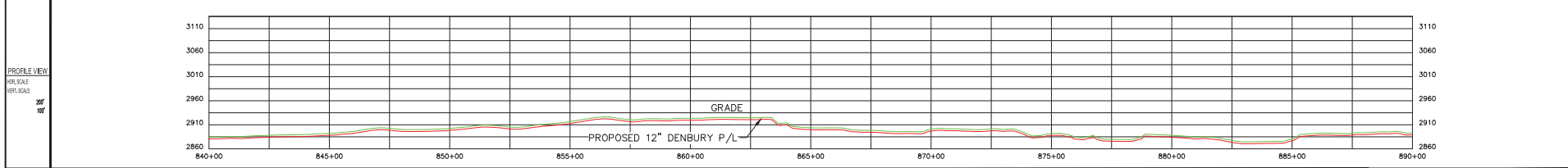
LEGEND PROPOSED PIPELINE EXISTING PIPELINE PERMANENT EASEMENT TEMPORARY EASEMENT CL ROAD ACCESS ROAD BANKLINE CL 20'00" SECTION LINE PROPERTY LINE OH POWER LINE INTERUM SPACE HEAVY WALL PPE WETLAND LIMITS LIND ROAD	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>MT. NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>5.000'</td> <td>12.75" O.D. x 0.460" WT-GR X 70MIL 14 - 18 MILS FIBRE LINE 989</td> </tr> <tr> <td>2</td> <td>0'</td> <td>12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FIBRE W/30-40 MILS ARD</td> </tr> <tr> <td>3</td> <td>1</td> <td>INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)</td> </tr> </tbody> </table>	MT. NO.	QTY.	DESCRIPTION	1	5.000'	12.75" O.D. x 0.460" WT-GR X 70MIL 14 - 18 MILS FIBRE LINE 989	2	0'	12.75" O.D. x 0.562" WT-GR X 70MIL 14 - 18 MILS FIBRE W/30-40 MILS ARD	3	1	INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021	REVISIONS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> <th>SCALE</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> <td>200'</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	SCALE	1	11/19/18	ISSUE FOR REVIEW	200'	PROPOSED 12" PIPELINE 790+00 TO 840+00 T132N R106W BOWMAN COUNTY, NORTH DAKOTA	42-063-LA-CHSULAT-220-0037-18 REC. A
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LEGEND (CONT.) HED POINT BORE SAMPLE LOCATION SECTION NUMBER CRACK ARRESTOR CONCRETE WEIGHTS HED/BORE AREA ADDITIONAL TEMP WORKSPACE (ATWS) CONCRETE COATING																																	

OWNERSHIP	840+00	CH NO. BD. 0020.000 DOUBLE S&K FLATNESS BRANCH L1EM 7148+00 RDS	841+00	CH NO. BD. 0021.000 SCOTT P BRIDGE 179.59+00 RDS	841+46	CH NO. BD. 0022.000 BIG ROCK ASSET INVESTMENT GROUP, LP 5179+00 RDS	890+00
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PIPELINE STATIONING		847+56 CL. OF ROAD 848+22 OVERHEAD POWER		843+17 TOE OF BANK 843+45 TOE OF BANK 843+75 TOE OF BANK 844+25 TOE OF BANK		869+44 TOE OF BANK 870+79 TOP OF BANK 873+47 TOP OF BANK 874+19 TOE OF BANK 874+08 TOE OF BANK 876+02 TOE OF BANK		879+75 TOE OF BANK 878+48 TOP OF BANK 881+43, 881+20, 881+21, 881+46 PROPERTY LINE 885+45 TOE OF BANK 885+13 TOP OF BANK
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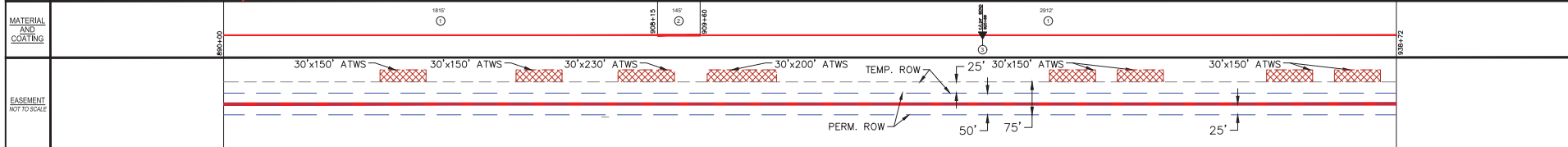
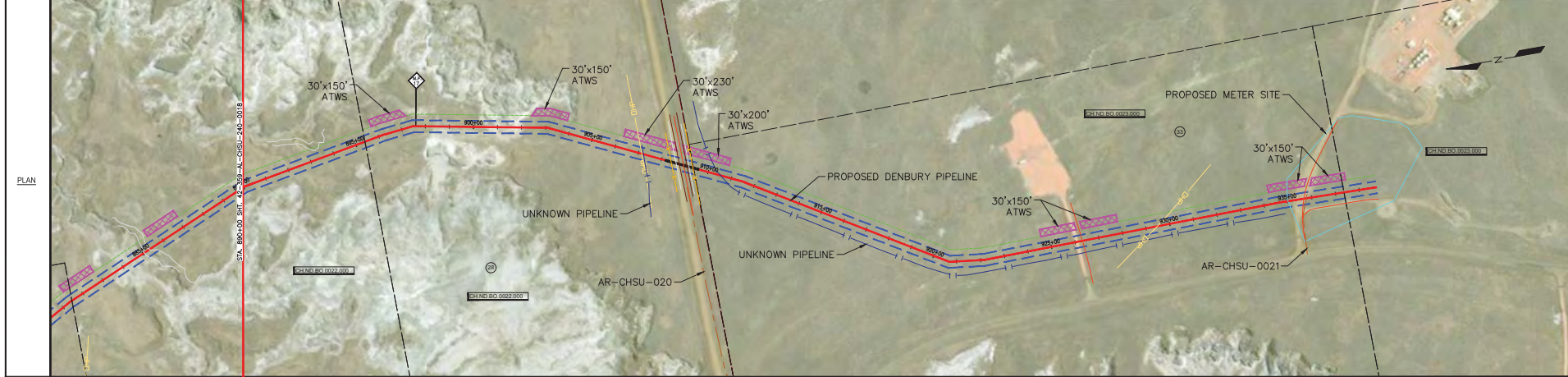


WETLANDS: WETLANDS, WETLANDS, WETLANDS
 ENVIRONMENTAL: WETLANDS, WETLANDS, WETLANDS
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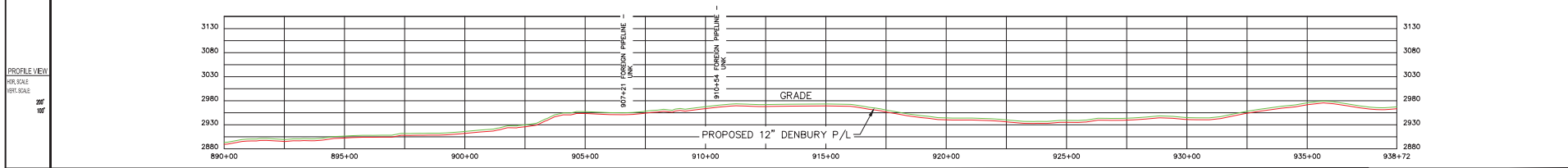


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1	11/19/18	ISSUE FOR REVIEW	200'																												
LEGEND (CONT.) HED POINT BORE SAMPLE LOCATION SECTION NUMBER CRACK ARRESTOR CONCRETE WEIGHTS HED/BORE AREA ADDITIONAL TEMP WORKSPACE (ATWS) CONCRETE COATING																															

OWNERSHIP	CH NO. BO. 0022.000 BIG ROCK ASSET INVESTMENT GROUP, LP 32.56 ACROSS	CH NO. BO. 0022.000 BIG ROCK ASSET INVESTMENT GROUP, LP 84.72 ACROSS	CH NO. BO. 0023.000 TODD & CARMEL MILLER 16.63 ACROSS	CH NO. BO. 0023.000 TODD & CARMEL MILLER 6.26 ACROSS
PIPELINE STATIONINGS	890+00 890+19 896+19 897+50 903+10 907+14 908+15 908+16 908+17 908+18 908+19 908+20 908+21 908+22 908+23 908+24 911+55	908+15 909+40 915+00 920+00 925+00 930+00 935+00 940+00	922+11 926+31 929+46 934+68 937+56	937+56 938+72



ENVIRONMENTAL
WETLANDS
WETLANDS BOUNDARIES
WETLANDS PERMITS
WETLANDS CONTROL



LEGEND 	NOTES 1. UNKNOWN UTILITY DEPTHS TO BE FIELD VERIFIED PRIOR TO CONSTRUCTION. 2. 4" MINIMUM DEPTH OF COVER REQUIRED.	MATERIAL SUMMARY <table border="1"> <thead> <tr> <th>AM. NO.</th> <th>QTY.</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>4.727'</td> <td>12.75" O.D. x 0.465" WT-GR X 70#AL 14 - 18 MILS FIBRE LINE 999</td> </tr> <tr> <td>2</td> <td>140'</td> <td>12.75" O.D. x 0.562" WT-GR X 70#AL 14 - 18 MILS FIBRE W/30-40 MILS ARD</td> </tr> <tr> <td>3</td> <td>1</td> <td>INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)</td> </tr> </tbody> </table>	AM. NO.	QTY.	DESCRIPTION	1	4.727'	12.75" O.D. x 0.465" WT-GR X 70#AL 14 - 18 MILS FIBRE LINE 999	2	140'	12.75" O.D. x 0.562" WT-GR X 70#AL 14 - 18 MILS FIBRE W/30-40 MILS ARD	3	1	INDUCTION BEND (SEE MATERIAL BAND FOR ANGLE)	REFERENCE DRAWINGS <table border="1"> <thead> <tr> <th>NO.</th> <th>DATE</th> <th>DESCRIPTION</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>11/19/18</td> <td>ISSUE FOR REVIEW</td> </tr> </tbody> </table>	NO.	DATE	DESCRIPTION	A	11/19/18	ISSUE FOR REVIEW	 350 INTERLOCKEN BLVD. SUITE 350 BROOMFIELD, CO. 80021	 PROPOSED 12" PIPELINE 890+00 TO 938+72 T32N R106W BOWMAN COUNTY, NORTH DAKOTA		
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REV.	A																								



Ecozone Reclamation Plans
Cedar Hills South Unit Lateral
Pipeline

Prepared for:
Denbury Resources, Inc.

Prepared by:
Duraroot, LLC

Date:
October 1, 2019

RECLAMATION PLAN

BADLANDS ECOZONE SITES



SITE DESCRIPTION

The Badlands Ecozone occurs in uplands on barren shoulders and backslopes of ridges and bluffs, as well as topographically low areas including alluvial fans and stream terraces. This ecozone covers approximately 9 acres of the Cedar Hills South Unit Lateral Pipeline Project. The Badlands Ecozone typically consists of moderately steep to steep slopes greater than 25 percent and can contain a restrictive layer in soil depths less than 10 inches. Soil formation is minimal with variable soil texture and high erosion potential. The Badlands Ecozone includes rocky outcrops with three percent or more of the ground surface covered by rock and contains little to no vegetative cover. Additionally, this ecozone can include fine textured soils (clay loams and clays) with characteristically elevated soil electrical conductivity (EC) and soil sodium adsorption ratio (SAR). These sites will be returned to similar pre-disturbance land use following construction.

A recommended seed mix is provided for the Badlands Ecozone in Table 1 and 2. The Badlands grass seed mix and shrub seed mix were developed using 60 and 10 pure live seeds (PLS) per square foot, respectively. This seed mix considers seed availability, original site composition, and desirable species for quick stabilization in erosive, shallow soils. These seed mixes were developed in consultation with regional USDA-NRCS guidelines and Montana State University Extension.

Key obstacles for reclamation in the Badlands Ecozone are steep slopes with high potential for erosion and shallow soils with potentially elevated soil salinity and soil attributes associated with sodic soils (soil dispersion, poor soil structure, hard surface crust formation, and reduced infiltration) and low water holding potential. Ecozone appropriate erosion control measures, seedbed preparation methods, suitable seed mixes, seeding practices, and a site specific Integrated Weed Management Plan (IWMP) should help expedite reclamation success. The Badlands Ecozone reclamation plan is provided on Page 2.

Table 1. Cedar Hills South Unit Lateral - Badlands Ecozone Sites Grass Seed Mix Recommendation for Year One Seeding.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Blue grama	<i>Bouteloua gracilis</i>	0.10	2	3%
Inland Saltgrass	<i>Distichlis spicata</i>	0.45	5	9%
Western Wheatgrass	<i>Pascopyrum smithii</i>	10.0	25	42%
Needle-and-Thread	<i>Hesperostipa comata</i>	4.09	11	18%
Indian Ricegrass	<i>Achnatherum hymenoides</i>	3.5	11	19%
Slender Wheatgrass	<i>Elymus trachycaulus</i>	1.5	5	9%
Total	--	19.6	60	100%

Table 2. Cedar Hills South Unit Lateral - Badlands Ecozone Shrub Seed Mix Recommendation for Year Two or Three Seeding.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Big Sagebrush	<i>Artemisia tridentata</i>	0.2	10	100%
Total	--	0.2	10	100%

Notes:

1. Seed mix was developed for badlands soil conditions and fine to medium soil textures based on vegetation data. Seed mix may be adjusted based landowner preferences.
2. PLS = Pure Live Seed



RECLAMATION PLAN

BADLANDS ECOZONE SITES

(1) SOIL AMENDMENTS

Soil amendment recommendations are based on recent soil chemical analysis. It is recommended that 125 lb/acre MAP (11-52-0) be applied to areas within the Badlands Ecozone.

- Nitrogen – 14 pounds per acre
- P₂O₅ – 65 pounds per acre
- K₂O - 0 pounds per acre

(2) SEEDBED PREPARATION

These recommended seedbed preparation steps will aid in successful reclamation. Steps may be omitted, conducted in different order, or changed to optimize success and efficiency depending on field conditions, sub-soil properties, and local terrain.

- When topographical slope allows, shallow rip subsurface soil prior to topsoil application to the maximum depth allowed to reduce soil compaction and improve drainage.
- Apply topsoil and soil amendments, discussed above, to supplement soil nutrients.
- Finally, till the site to a depth of 4.0 to 6.0 inches to create a seedbed conducive to seedling establishment (disk and harrow, field cultivator, vibra-shank, or other alternative suitable to site conditions). Tillage is dependent on topographical slope. If slopes are too steep, implement minimal till practices.

(3) SEEDING

Seeding should be conducted in a two-stage process to establish shrubs on the ROW. Seeding should be completed within 45-days of reclamation using the grass seed mix and rate provided in Table 1. Establishment of resilient grass species will be critical in managing weed populations and improving soil conditions for shrub and forb growth. Manage and monitor weedy species establishment within the first two years from seeding. After grass establishment, seed using the recommended seed mix to achieve desired shrub species. Grass seeding should be conducted using a drill seeder suitable for the location's soils and capable of direct seed placement. Drill seeding should occur on the contour using a drill equipped with an agitator and double disc opener with a wheel press and depth bands to mix seed and ensure proper seeding depths. Seeds should be planted to the depth specified by the vendor to ensure proper germination and emergence. It is recommended that the seed be placed $\frac{1}{8}$ to $\frac{1}{2}$ inch deep.

Broadcast seed shrubs at the recommended rates in Table 2 in the second or third year to achieve the desired plant community. Dormant seeding shrubs is preferred for greatest success. In Montana, shrubs should be seeded between November 1st and March 15th and immediately following snowfall. A snow base of less than 8 inches is ideal to help settle the seed into the soil. If the seeding conditions are not met in year two, shrubs should be planted in year 3. On non-BLM land shrubs should only be seeded when requested by the landowner. The Badlands Ecozone seed mixes and rates are provided in Table 1 and 2.

(4) EROSION CONTROL

Because of steep slope gradients and high erosion potential, all disturbances in the Badlands Ecozone should be hydro-mulched using a bonded fiber matrix (BFM) or flexible growth medium (FGM). Hydro-mulch application will stabilize slopes during reclamation and protect seed until vegetation can successfully establish. A synthetic polymer product, such as polyacrylamide (PAM), could be added to the hydro-mulch solution to encourage soil aggregation and further reduce erosion potential. In areas with limited available soil material a Biotic Soil Media (BSM) can be used to improve grass establishment.

Additional erosion control devices (ECDs) appropriate for specific site conditions should be installed and maintained during all construction and reclamation activities through final site stabilization. Implementing ECDs will minimize erosion of disturbed soils and prevent the transportation of sediment outside the construction ROW and into environmentally sensitive areas such as wetlands, waterbodies, and agricultural lands. Erosion control devices should be employed as needed.

RECLAMATION PLAN

BADLANDS ECOZONE SITES



(5) WEED MANAGEMENT

Regular inspection of the pipeline ROW and other soil disturbance areas prior to construction will aid in noxious/invasive weed control. Weed management should be diligent within the first one to two years to prevent infestation and allow for native species establishment. A site-specific Integrated Weed Management Plan should be developed once weedy species can be identified. Sites could be mowed prior to flowering and seed head production of weedy species. Mowing will reduce competition with desirable species and allow greater opportunity for reclamation success. In addition to mowing, herbicides appropriate for the identified weedy species should be implemented into the weed management plan to eradicate any problematic species. Application timing and rates should follow the manufacturer's recommendations. Herbicide applications should be selective and avoid desirable native grass, forb, and shrub species. It is recommended to avoid overgrazing during the establishment period to minimize competitive weedy species establishment. All disturbed sites should be promptly seeded following construction to minimize the window of opportunity for new weed invasion.

RECLAMATION PLAN

CULTIVATED CROP ECOZONE SITES



SITE DESCRIPTION

The Cultivated Cropland Ecozone is comprised primarily of managed forage and hay crops. The Cultivated Crop Ecozone makes up approximately 25 acres of the Cedar Hills South Unit Lateral Pipeline Project. Following construction, the land will be returned to productive cropland. The Cultivated Crop Ecozone contains primarily loams, with slopes generally less than 10 percent. Soils are predominately fine textured loams and neutral to slightly alkaline. One key factor in reclaiming the Cultivated Crop Ecozone sites will be the preservation of topsoil, which has the soil properties necessary for agricultural production. This ecozone should present minimal challenges for reclamation due to desirable ecozone characteristics.

The cover crop seed mixes provided in Table 1 and 2 should be seeded on all cultivated cropland when establishment of the crop will not occur within 45 days of reclamation activities. Cover crops will protect the soil from wind and water erosion, increase soil stabilization, improve soil structure, suppress weed establishment, and improve overall reclamation success. The cover crop seed mixes below were developed to provide cover due to a quick germination rate and aid in accelerated soil stabilization by helping to prevent the migration of topsoil during periods of freeze/thaw and rain events. Cool season cover crops should be used mid-March to mid-May and August through September. Cover crop seed mix recommendations for immediate vegetation cover are provided in Tables 1 and 2. The reclamation plan is provided on Page 2.

Table 1. Recommended cool season (March 15 to May 15 or August 15 to October 1) cover crop seed mix.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Barley	<i>Hordeum vulgare</i>	60	18	100
Total	--	60		100%

Table 2. Recommended warm season (May 15 to August 15) cover crop seed mix.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Pearl Millet	<i>Pennisetum glaucum</i>	20	28	100%
Total	--	20		100%

Notes:

1. Seed mix was developed for cultivated row crops. Seed mix may be adjusted based on landowner preferences.
2. PLS = Pure live seed



RECLAMATION PLAN

CULTIVATED CROP ECOZONE SITES

(1) SOIL AMENDMENTS

It is recommended that 125 lb/acre of MAP (11-52-0) fertilizer be added at the time of cover crop seeding to fields within the Cultivated Crop Ecozone sites.

- Nitrogen - 14 pounds per acre
- P₂O₅ – 65 pounds per acre
- K₂O - 0 pounds per acre

(2) SEEDBED PREPARATION

These recommended seedbed preparation steps will aid in successful reclamation. Steps may be omitted, conducted in different order, or changed to optimize success and efficiency depending on field conditions, sub-soil properties, and local terrain.

- Rip subsurface soil, prior to topsoil spreading, to a minimum of 16 inches to reduce soil compaction and improve drainage. The shanks on the back of a grader or dozer should NOT be used to alleviate soil compaction. Do not smooth the ROW with a dozer once ripped it is beneficial to have an irregular surface to help tie the topsoil and subsoil horizons together. Tillage can be used to break soil clods apart prior to topsoil application.
- Apply topsoil and soil amendments, discussed above, to improve the soil physical and chemical characteristics and to supplement soil nutrients.
- Finally, till the site to a depth of 4.0 to 6.0 inches to incorporate soil amendments and to create a seedbed conducive to seedling establishment (disk and harrow, field cultivator, vibra-shank, or other alternative suitable to site conditions).

(3) SEEDING

Seeding should be conducted using a drill seeder suitable for the location's soils and capable of direct seed placement. Drill seeding should occur on the contour using a drill equipped with an agitator and double disc opener with a wheel press and depth bands to mix seed and ensure proper seeding depths. Seeds should be planted to the depth specified by the vendor to ensure proper germination and emergence. It is recommended that the seed be placed $\frac{1}{8}$ to $\frac{1}{2}$ inch deep. The Cultivated Crop Ecozone seed mixes and rates are provided in Tables 1 and 2.

(4) STRAW MULCHING

Application of straw mulch is recommended to reduce potential water and wind erosion on sandy soils. Recommended straw mulch application rates are between 1.5 to 2.0 tons per acre. This will provide ground coverage of approximately 80 to 90 percent of the ground surface prior to crimping. Once applied the straw mulch should be crimped into the soil using a straight disc crimper with 8.0 inches spaced tines. Upon successful crimping the straw mulch should be standing vertically with approximately 40 to 60 percent of the ground surface covered. Straw mulch should be at least 6.0 inches in length. Straw mulch should be crimped sufficiently to cause vertical cover that will not be dislodged by light breezes. Straw mulch should be applied based on landowner preference in cultivated areas.

(5) WEED MANAGEMENT

Regular inspection of the pipeline ROW and other soil disturbance areas prior to construction will aid in noxious/invasive weed control. Weed management should be diligent within the first one to two years to prevent infestation and allow for native species establishment. A site-specific Integrated Weed Management Plan should be developed once weedy species can be identified. Sites could be mowed prior to flowering and seed head production of weedy species. Mowing will reduce competition with desirable species and allow greater opportunity for reclamation success. In addition to mowing, herbicides appropriate for the identified weedy species should be implemented into the weed management plan to eradicate any problematic species. Application timing and rates should follow the manufacturer's recommendations. Herbicide applications should be selective and avoid desirable native grass, forb, and shrub species. It is recommended to avoid overgrazing during the establishment period to minimize competitive weedy species establishment. All disturbed sites should be promptly seeded following construction to minimize the window of opportunity for new weed invasion.

RECLAMATION PLAN

LOAMY ECOZONE SITES



SITE DESCRIPTION

The Loamy Ecozone consists primarily of grassland used for livestock grazing, forage production, and wildlife. This ecozone covers the majority of the Cedar Hills South Unit Lateral Pipeline Project, approximately 95 acres. The Loamy Ecozone is composed of tall and short/mid grasslands and consists of loamy soil types over varying topography. Vegetation within this ecozone consists of diverse herbaceous plant communities where 50 to 90 percent of the vegetation are grasses. Pastures consist primarily of an alfalfa/grass mix and native range is primarily native/introduced grasses and forbs. These sites will be returned to a similar pre-disturbance landuse following construction.

A recommended seed mix is provided for the Loamy Ecozone sites in Table 1 and 2. The native grass seed mix and forb/shrub seed mixes were developed using 60 and 40 pure live seed (PLS) per square foot, respectively. Seed mixes consider seed availability, original site composition, and the ability of species to thrive in this specific ecozone. These seed mixes were developed in consultation with regional USDA-NRCS guidelines and Montana State University Extension.

The Loamy Ecozone should present minimal challenges for reclamation due to desirable ecozone characteristics. Appropriate seedbed preparation methods, seeding practices, a suitable seed mix, and a site specific Integrated Weed Management Plan should help expedite reclamation success. The reclamation plan is provided on Page 2.

Table 1. Cedar Hills South Unit Lateral - Loamy Ecozone Site Grass Seed Mix Recommendation for Year One Seeding.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Sandbergs Bluegrass	<i>Poa secunda</i>	0.7	15	25%
Green Needlegrass	<i>Nassella viridula</i>	2.2	9	15%
Western Wheatgrass	<i>Pascopyrum smithii</i>	5.9	15	25%
Thickspike Wheatgrass	<i>Elymus lanceolatus</i>	1.7	6	10%
Blue grama	<i>Bouteloua gracilis</i>	0.5	9	15%
Prairie Junegrass	<i>Koeleria macrantha</i>	0.1	6	10%
Total	--	11.1	60	100%

Table 2. Cedar Hills South Unit Lateral - Loamy Ecozone Site Forb/Shrub Seed Mix Recommendation for Year Two or Three Seeding.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Forb/Shrub Mix	% of Total Mix
Scarlett Globemallow	<i>Sphaeralcea coccinea</i>	0.2	3	7%	3%
Purple Prairie Clover	<i>Dalea purpureum</i>	0.6	3	7%	3%
Two-grooved Milkvetch	<i>Astragalus bisulcatus</i>	1.4	3	7%	3%
Dotted Gayfeather	<i>Liatris punctata</i>	0.8	2	5%	2%
Greasewood	<i>Sarcobatus vermiculatus</i>	0.9	5	12%	5%
Gardner Saltbrush	<i>Atriplex gardneri</i>	2.0	5	13%	5%
Winterfat	<i>Krascheninnikovia lanata</i>	3.3	10	24%	10%
Big Sagebrush	<i>Artemisia tridentata</i>	0.2	10	25%	10%
Total	--	9.4	40	100%	40%

Notes:

1. Seed mix was developed for loamy soil conditions and fine to medium soil textures based on vegetation data. Seed mix may be adjusted based landowner preferences.
2. PLS = Pure Live Seed

RECLAMATION PLAN

LOAMY ECOZONE SITES



(1) SOIL AMENDMENTS

Soil amendment recommendations are based on recent soil chemical analysis, when available. It is recommended that 125 lb/acre MAP (11-52-0) be applied to areas within the Loamy Ecozone.

- Nitrogen – 14 pounds per acre
- P₂O₅ – 65 pounds per acre
- K₂O - 0 pounds per acre

(2) SEEDBED PREPARATION

These recommended seedbed preparation steps will aid in successful reclamation. Steps may be omitted, conducted in different order, or changed to optimize success and efficiency depending on field conditions, sub-soil properties, and local terrain.

- Rip subsurface soil, prior to topsoil application, to a minimum of 18 inches to reduce soil compaction and improve drainage. The shanks on the back of a grader or dozer should NOT be used to reduce soil compaction. Do not smooth the ROW with a dozer once ripped it is beneficial to have an irregular surface to help tie the topsoil and subsoil horizons together. Tillage can be used to break soil clods apart prior to topsoil application.
- Apply topsoil and soil amendments, discussed above, to improve the soil physical and chemical characteristics and to supplement soil nutrients.
- Finally, till the site to a depth of 4.0 to 6.0 inches to incorporate soil amendments and to create a seedbed conducive to seedling establishment (disk and harrow, field cultivator, vibra-shank, or other alternative suitable to site conditions).

(3) SEEDING

Seeding should be conducted in a two-stage process to establish forbs and shrubs on the ROW. Seeding should be completed within 45-days of reclamation using the grass seed mix and rate provided in Table 1. Establishment of resilient grass species will be critical in managing weed populations and improving soil conditions for shrub and forb growth. Manage and monitor weedy species establishment within the first two years from seeding. After grass establishment, seed using the recommended seed mix to achieve desired forb and shrub species. Grass seeding should be conducted using a drill seeder suitable for the location's soils and capable of direct seed placement. Drill seeding should occur on the contour using a drill equipped with an agitator and double disc opener with a wheel press and depth bands to mix seed and ensure proper seeding depths. Seeds should be planted to the depth specified by the vendor to ensure proper germination and emergence. It is recommended that the seed be placed $\frac{1}{8}$ to $\frac{1}{2}$ inch deep.

Broadcast seed forbs and shrubs at the recommended rates in Table 2 in the second or third year to achieve the desired plant community. Dormant seeding forbs and shrubs is preferred for greatest success. In Montana, forbs and shrubs should be seeded between November 1st and March 15th and immediately following snowfall. A snow base of less than 8 inches is ideal to help settle the seed into the soil. If the seeding conditions are not met in year two, forbs and shrubs should be planted in year 3. On non-BLM land forbs and shrubs should only be seeded when requested by the landowner. The Loamy Ecozone seed mixes and rates are provided in Table 1 and 2.

(4) STRAW MULCHING

Application of straw mulch is recommended to reduce potential water and wind erosion on sandy soils. Recommended straw mulch application rates are between 1.5 to 2.0 tons per acre. This will provide ground coverage of approximately 80 to 90 percent of the ground surface prior to crimping. Once applied the straw mulch should be crimped into the soil using a straight disc crimper with 8.0 inches spaced tines. Upon successful crimping the straw mulch should be standing vertically with approximately 40 to 60 percent of the ground surface covered. Straw mulch should be at least 6.0 inches in length. Straw mulch should be crimped sufficiently to cause vertical cover that will not be dislodged by light breezes.

RECLAMATION PLAN

LOAMY ECOZONE SITES



(5) WEED MANAGEMENT

Regular inspection of the pipeline ROW and other soil disturbance areas prior to construction will aid in noxious/invasive weed control. Weed management should be diligent within the first one to two years to prevent infestation and allow for native species establishment. A site-specific Integrated Weed Management Plan should be developed once weedy species can be identified. Sites could be mowed prior to flowering and seed head production of weedy species. Mowing will reduce competition with desirable species and allow greater opportunity for reclamation success. In addition to mowing, herbicides appropriate for the identified weedy species should be implemented into the weed management plan to eradicate any problematic species. Application timing and rates should follow the manufacturer's recommendations. Herbicide applications should be selective and avoid desirable native grass, forb, and shrub species. It is recommended to avoid overgrazing during the establishment period to minimize competitive weedy species establishment. All disturbed sites should be promptly seeded following construction to minimize the window of opportunity for new weed invasion.

RECLAMATION PLAN

SALINE ECOZONE SITES



SITE DESCRIPTION

The Saline Ecozone consists of land used primarily for forage production and grazing. The Saline Ecozone makes up approximately 45 acres of the Cedar Creek Pipeline Project. This ecozone occurs in topographically low areas, including alluvial fans and stream terraces, as well as on hillslopes. This ecozone consists of fine textured soils (clay loams and clays) with characteristically elevated soil electrical conductivity (EC) and soil sodium adsorption ratio (SAR). Soils are moderately deep to deep (> 20 inches) and slope typically ranges from 0 to 8 percent. Vegetation of the Saline Ecozone is predominantly native/introduced rangeland grasses. These sites will be returned to a similar pre-disturbance land use following construction.

A recommended seed mix is provided for the Saline Ecozone in Table 1 and 2. The grass and forb/shrub seed mixes were developed using 80 and 10 pure live seeds (PLS) per square foot, respectively. It is recommended that an additional 20 pounds per acre of barley (*Hordeum vulgare*) or Sterile Triticale (*Triticale hexaploide*) be added as nurse crop for immediate stabilization. This seed mix considers inherent soil properties and includes saline tolerant grass species to improve reclamation success.

One key obstacle in reclaiming the Saline Ecozone sites will be the elevated soil salinity and potential soil attributes associated with sodic soils (soil dispersion, poor soil structure, hard surface crust formation, and reduced infiltration). Ecozone appropriate soil amendments, seedbed preparation methods, seeding practices, a suitable seed mix, and a site specific Integrated Weed Management Plan should help expedite reclamation success. The reclamation plan is provided on Page 2.

Table 1. Cedar Hills South Unit Lateral – Saline Ecozone Site Grass Seed Mix Recommendation for Year One Planting.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Bottlebrush Squirreltail	<i>Elymus elymoides</i>	4.5	20	25%
Inland Saltgrass	<i>Distichlis spicata</i>	1.7	20	25%
Western Wheatgrass	<i>Pascopyrum smithii</i>	6.3	16	20%
Nuttall's alkalgrass	<i>Puccinellia nuttalliana</i>	0.2	12	15%
Slender Wheatgrass	<i>Elymus trachycaulus</i>	3.3	12	15%
Total	--	16.1	80	100%

Table 2. Cedar Hills South Unit Lateral – Saline Ecozone Site Shrub Seed Mix Recommendation for Year Two or Three Planting.

Common Name	Scientific Name	# PLS/acre	PLS/sq ft	% of Mix
Big Sagebrush	<i>Artemisia tridentata</i>	0.2	10	100%
Total	--	0.2	10	100%

Notes:

1. Seed mix was developed for saline soil conditions and fine to medium soil textures based on vegetation data. Seed mix may be adjusted based landowner preferences.
2. PLS = Pure Live Seed



RECLAMATION PLAN

SALINE ECOZONE SITES

(1) SOIL AMENDMENTS

Soil amendments are recommended to expedite reclamation success and create conditions that can better support seed germination and plant growth. To improve soil structure and to reduce potential soil dispersion of saline/sodic soils, it is recommended that 1.5 tons/acre gypsum be applied to soils within the Saline Ecozone. To expedite plant growth, it is recommended that 100 lb/acre MAP (11-52-0) and 80 lb/acre Urea (46-0-0) be applied and incorporated post topsoil application to a depth of 4.0 to 6.0 inches.

- Gypsum – 1.5 tons per acre
- Nitrogen – 48 pounds per acre
- P₂O₅ – 52 pounds per acre

(2) SEEDBED PREPARATION

These recommended seedbed preparation steps will aid in successful reclamation. Steps may be omitted, conducted in different order, or changed to optimize success and efficiency depending on field conditions, sub-soil properties, and local terrain.

- Rip subsurface soil, prior to topsoil application, to a minimum of 16 inches to reduce soil compaction and improve drainage. Ripping should be conducted using a double pass with a straight-shank agricultural ripper or parabolic ripper. The shanks on the back of a grader or dozer should NOT be used to alleviate soil compaction. Do not smooth the ROW with a dozer once ripped it is beneficial to have an irregular surface to help tie the topsoil and subsoil horizons together. Tillage can be used to break soil clods apart prior to topsoil application.
- Apply topsoil and soil amendments, discussed above, to improve the soil physical and chemical characteristics and to supplement soil nutrients.
- Finally, till the site to a depth of 4.0 to 6.0 inches to incorporate soil amendments and to create a seedbed conducive to seedling establishment (disk and harrow, field cultivator, vibra-shank, or other alternative suitable to site conditions).

(3) SEEDING

Seeding should be conducted in a two-stage process to establish forbs and shrubs on the ROW. Seeding should be completed within 45-days of reclamation using the seed mix and rate provided in Table 1. Establishment of resilient grass species will be critical in managing weed populations and improving soil conditions for shrub and forb growth. Manage and monitor weedy species establishment within the first two years from seeding. After grass establishment, seed using the recommended seed mix to achieve desired shrub species. Grass seeding should be conducted using a drill seeder suitable for the location's soils and capable of direct seed placement. Drill seeding should occur on the contour using a drill equipped with an agitator and double disc opener with a wheel press and depth bands to mix seed and ensure proper seeding depths. Seeds should be planted to the depth specified by the vendor to ensure proper germination and emergence. It is recommended that the seed be placed 1/8 to 1/2 inch deep.

Broadcast seed shrubs at the recommended rates in Table 2 in the second or third year to achieve the desired plant community. Dormant seeding shrubs is preferred for greatest success. In Montana, shrubs should be seeded between November 1st and March 15th and immediately following snowfall. A snow base of less than 8 inches is ideal to help settle the seed into the soil. If the seeding conditions are not met in year two, shrubs should be planted in year three. On non-BLM land shrubs should only be seeded when requested by the landowner. The Saline Ecozone seed mixes and rates are provided in Table 1 and 2.

(4) STRAW MULCHING

Application of straw mulch is recommended to reduce potential water and wind erosion. Recommended straw mulch application rates are between 1.5 to 2.0 tons per acre. This will provide ground coverage of approximately 80 to 90 percent of the ground surface prior to crimping. Once applied the straw mulch should be crimped into the soil using a straight disc crimper with 8.0 inches spaced tines. Upon successful crimping the straw mulch should be standing vertically with approximately 40 to 60 percent of the ground surface covered. Straw mulch should be at least 6.0 inches in length. Straw mulch should be crimped sufficiently to cause vertical cover that will not be dislodged by light breezes.

RECLAMATION PLAN

SALINE ECOZONE SITES



(5) WEED MANAGEMENT

Regular inspection of the pipeline ROW and other soil disturbance areas prior to construction will aid in noxious/invasive weed control. Weed management should be diligent within the first one to two years to prevent infestation and allow for native species establishment. A site-specific Integrated Weed Management Plan should be developed once weedy species can be identified. Sites could be mowed prior to flowering and seed head production of weedy species. Mowing will reduce competition with desirable species and allow greater opportunity for reclamation success. In addition to mowing, herbicides appropriate for the identified weedy species should be implemented into the weed management plan to eradicate any problematic species. Application timing and rates should follow the manufacturer's recommendations. Herbicide applications should be selective and avoid desirable native grass, forb, and shrub species. It is recommended to avoid overgrazing during the establishment period to minimize competitive weedy species establishment. All disturbed sites should be promptly seeded following construction to minimize the window of opportunity for new weed invasion.

ATTACHMENT A

Soil Data Cedar Hills South Unit Lateral Pipeline

Pipeline	Sample ID	pH	ECe dS/m	SAR	Ca ppm	Mg ppm	Na ppm	N lb/acre	P-O ppm	K ppm	OM %	Ecozone
CHSU	1	7.8	0.15	0	2536	127	17	1	3	223	2	Loamy
CHSU	4	8.2	0.25	0	2927	316	19	2	2	109	1	Loamy
CHSU	13	6.7	0.31	0.28	1496	239	19	3	2	181	3.5	Loamy
CHSU	17	7.9	0	0.40	1374	217	19	1	4	124	1.1	Loamy
CHSU	23	8.2	0.71	1.14	3384	630	81	2	14	308	2.6	Loamy
CHSU	26	7.6	0.18	0.03	1715	417	17	3	2	173	2.6	Loamy
CHSU	28	7.6	0	3.13	1046	290	59	1	4	151	2.1	Loamy
CHSU	31	8.9	1.62	17.8	2368	362	625	1	35	244	0.8	Saline
CHSU	37	7.7	0.37	0.28	1819	381	25	2	3	250	1.9	Loamy
CHSU	42	7.4	0	3.01	941	215	48	3	2	103	1.8	Loamy
CHSU	45	7.4	0.12	0	1775	310	14	4	4	304	3.9	Loamy
CHSU	50	8.0	0.06	1.14	1014	237	28	1	4	295	1.6	Loamy
CHSU	55	7.5	0	0.40	878	201	14	3	5	211	1.1	Loamy
CHSU	60	7.8	0	0.52	967	190	16	4	4	243	1.3	Crop
CHSU	65	6.7	0	0.77	972	216	20	1	3	144	1	Loamy
CHSU	69	6.7	0.03	0.15	1420	270	16	4	2	293	2.9	Loamy
CHSU	72	6.7	0.15	0.03	1460	290	16	4	3	267	2.2	Loamy
CHSU	79	7.6	0.31	1.76	1802	263	58	10	12	397	2.5	Crop
CHSU	84	7.6	0	0.52	1114	330	21	3	2	159	1.5	Saline
CHSU	88	7.3	0.31	0.40	1312	456	23	1	2	206	2.9	Saline
CHSU	91	7.9	7.20	0.65	12677	515	183	2	2	345	2.9	Saline
CHSU	96	7.7	0.09	10.2	800	385	175	1	3	253	2.3	Loamy
CHSU	100	7.0	0.12	0.15	1576	530	22	2	2	276	3.5	Loamy
CHSU	103	7.5	0.12	0	1727	484	16	2	2	274	3.4	Loamy
CHSU	107	7.5	0.28	0	1994	488	16	1	3	283	3.9	Loamy
CHSU	111	7.6	13.1	20.6	6619	1017	2040	3	2	405	1.9	Saline
CHSU	114	7.6	1.93	0.15	6215	273	55	17	21	487	21.3	Saline

Pipeline	Sample ID	pH	ECe dS/m	SAR	Ca ppm	Mg ppm	Na ppm	N lb/acre	P-O ppm	K ppm	OM %	Ecozone
CHSU	119	5.1	11.5	21.3	4373	981	1592	1	31	377	1.7	Saline
CHSU	124	6.9	6.80	16.7	2471	932	815	4	31	411	2.1	Saline
Crop	Average	7.7	0.2	1.1	1385	227	37.0	7.0	8.0	320	1.9	
	MIN	7.6	0	0.52	967	190	16	4	4	243	1.3	
	MAX	7.8	0.3	1.8	1802	263	58	10	12	397	2.5	
Loamy	Average	7.5	0.2	1.1	1624	329	33.7	2.2	3.5	222	2.3	
	MIN	6.7	0	0	800	127	14	1	2	103	1	
	MAX	8.2	0.7	10.2	3384	630	175	4	14	308	3.9	
Saline	Average	7.4	5.3	9.8	4644	608	669	4.0	15.8	329	4.4	
	MIN	5.1	0	0.15	1114	273	21	1	2	159	0.8	
	MAX	8.9	13.1	21.3	12677	1017	2040	17	35	487	21.3	

Notes:

1. Soil sample analytical results from soil samples collected during the fall of 2019.
2. Red highlighted cells could potentially impair reclamation success.

Cedar Creek Anticline (CCA) EOR Development Project

Noxious Weed Management Plan

Prepared for
Denbury Onshore, LLC

Prepared by
SWCA Environmental Consultants
295 Interlocken Blvd., Suite 300
Broomfield, CO 80021
(303) 487-1183 / Fax (303) 487-1245
www.swca.com

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A	Noxious weed occurrence table
B	Potential control options for noxious species
C	Pesticide Use Proposal

1.0 INTRODUCTION

Noxious and invasive weeds can move into disturbed areas and dominate or disrupt natural communities or restoration projects. Noxious weeds compete with native species for soil, water, and other limiting resources. Noxious weeds are often able to out-compete native vegetation and can form monocultures. This degrades the value of agricultural and natural resources, including wildlife habitat. Management of noxious weeds is a reclamation requirement in the Montana Bureau of Land Management (BLM) Approved Resource Management Plan Amendments (BLM 2015). The Miles City Field Office of the BLM has zero tolerance for state-listed noxious weed species. Therefore, weed management is an important part of the reclamation procedures outlined in the Reclamation Plan for the Project.

This Programmatic Noxious Weed Management Plan for the Cedar Creek Anticline (CCA) EOR Development Project (Project) provides an overview of the noxious weed goals and standards that will be used to ensure successful treatment of noxious weeds in disturbed areas created by the Project. These standards are designed to establish the potential methodologies, monitoring, and reporting requirements for noxious weed treatment associated with this Project.

This plan is in accordance with Federal Invasive Species Executive Order 13112, which defines noxious weeds as alien, non-native, species whose introduction causes or is likely to cause economic or environmental damage or harm to human health (U.S. Federal Register 1999). In accordance with the Federal Plant Protection Act of 2000, as amended (United States Code 2001), the BLM requires that NEPA documents consider and analyze the potential for the spread of noxious weed species and provide preventative rehabilitation measures for each management action involving surface disturbance. The BLM considers plants noxious if they have been introduced into an environment where they did not evolve. In addition, a noxious weed is any plant designated by a federal, state, or county government as injurious to public health, agriculture, recreation, wildlife or property.

Each state is federally mandated to uphold the rules and regulations set forth by the Federal Plant Protection Act of 2000 and manage their lands according. Montana state legislation has passed the following eight laws that regulate the management of noxious weeds:

- Montana County Weed Control Act (Title 7, Chapter 22, Part 21);
- Montana Weed Control Act (Title 80, Chapter 7, Part 7);
- Montana Noxious Weed Trust Fund Act (Title 80, Chapter 7, Part 811);
- Montana Noxious Weed Seed Free Forage Act (Title 80, Chapter 7, Part 9);
- Montana Agriculture Seed Act (Title 80, Chapter 5, Part 1);
- Montana Environmental Policy Act (Title 75, Chapter 1); and
- Montana Nursery Act. (Title 80, Chapter 7, Part 1)

These laws were designed to complement regional, national, and international strategies in the National Invasive Species Management Plan (NISC 2008). County weed districts (CWDs) are responsible for implementing and enforcing the regulations set forth in the Montana County Weed Control Act (State of Montana 2015).

A list of the noxious weed species designated by the State of Montana, and Carter, Fallon, and Powder River counties are provided in Table 1.

Table 1. State of Montana, and Fallon, Carter, and Powder River Counties Weed List

STATE OF MONTANA NOXIOUS WEED LIST*	
<i>Effective: July 2015</i>	
Priority 1A¹	
Yellow starthistle	<i>Centaurea solstitialis</i>
Dyer's woad	<i>Isatis tinctoria</i>
Common Reed	<i>Phragmites australis</i> ssp. <i>australis</i>
Priority 1B²	
Knotweed complex	<i>Polygonum cuspidatum</i> , <i>P. sachalinense</i> , <i>P. × bohemicum</i> , <i>Fallopia japonica</i> , <i>F. sachalinensis</i> , <i>F. × bohémica</i> , <i>Reynoutria japonica</i> , <i>R. sachalinensis</i> , and <i>R. × bohémica</i>
Purple loosestrife	<i>Lythrum salicaria</i>
Rush skeletonweed	<i>Chondrilla juncea</i>
Scotch broom	<i>Cytisus scoparius</i>
Priority 2A³	
Tansy ragwort	<i>Senecio jacobaea</i> and <i>Jacobaea vulgaris</i>
Meadow hawkweed complex	<i>Hieracium caespitosum</i> , <i>H. praealtum</i> , <i>H. floridundum</i> , and <i>Pilosella caespitosa</i>
Orange hawkweed	<i>Hieracium aurantiacum</i> and <i>Pilosella aurantiaca</i>
Tall buttercup	<i>Ranunculus acris</i>
Perennial pepperweed	<i>Lepidium latifolium</i>
Yellowflag iris	<i>Iris pseudacorus</i>
Blueweed	<i>Echium vulgare</i>
Eurasian watermilfoil	<i>Myriophyllum spicatum</i>
Flowering rush	<i>Butomus umbellatus</i>
Priority 2B⁴	
Hoary alyssum	<i>Berteroa incana</i>
Canada thistle	<i>Cirsium arvense</i>
Field bindweed	<i>Convolvulus arvensis</i>
Leafy spurge	<i>Euphorbia esula</i>
Whitetop	<i>Cardaria draba</i> or <i>Lepidium draba</i>
Russian knapweed	<i>Acroptilon repens</i> or <i>Rhaponticum repens</i>
Spotted knapweed	<i>Centaurea stoebe</i> and <i>C. maculosa</i>
Diffuse knapweed	<i>Centaurea diffusa</i>
Dalmatian toadflax	<i>Linaria dalmatica</i>

STATE OF MONTANA NOXIOUS WEED LIST*	
<i>Effective: July 2015</i>	
St. Johnswort	<i>Hypericum perforatum</i>
Sulfur cinquefoil	<i>Potentilla recta</i>
Common tansy	<i>Tanacetum vulgare</i>
Oxeye daisy	<i>Leucanthemum vulgare</i>
Houndstongue	<i>Cynoglossum officinale</i>
Yellow toadflax	<i>Linaria vulgaris</i>
Saltcedar	<i>Tamarix</i> spp.
Curlyleaf pondweed	<i>Potamogeton crispus</i>
Priority 3 Regulated Plants⁵	
Cheatgrass	<i>Bromus tectorum</i>
Hydrilla	<i>Hydrilla verticillata</i>
Russian olive	<i>Elaeagnus angustifolia</i>
Brazilian waterweed	<i>Egeria densa</i>
Parrot feather watermilfoil	<i>Myriophyllum aquaticum</i> and <i>M. brasiliense</i>
POWDER RIVER COUNTY – Listed Species	
Poison hemlock	<i>Conium maculatum</i>
Puncturevine	<i>Tribulus terrestris</i>
Black henbane	<i>Hyoscyamus niger</i>
CARTER COUNTY – Listed Species	
Common burdock	<i>Arctium minus</i>
Poison hemlock	<i>Conium maculatum</i>
FALLON COUNTY – Listed Species	
Common crupina	<i>Crupina vulgaris</i>

¹ Priority 1A - These weeds are not present or have a very limited presence in Montana. Management criteria will require eradication if detected, education, and prevention.

² Priority 1B - These weeds have limited presence in Montana. Management criteria will require eradication or containment and education.

³ Priority 2A - These weeds are common in isolated areas of Montana. Management criteria will require eradication or containment where less abundant. Management shall be prioritized by local weed districts.

⁴ Priority 2B - These weeds are abundant in Montana and widespread in many counties. Management criteria will require eradication or containment where less abundant. Management shall be prioritized by local weed districts.

⁵ Priority 3 Regulated Plants - These regulated plants have the potential to have significant negative impacts. The plant may not be intentionally spread or sold other than as a contaminant in agricultural products. The state recommends research, education, and prevention to minimize the spread of the regulated plant (Not Montana listed noxious weeds).

*Montana Department of Agriculture, 2015. Montana Noxious Weed List, July 2015. <http://agr.mt.gov>

1.1 PLAN PURPOSE

The purpose of the plan is to prescribe methods to prevent and control the spread of noxious weeds during and following construction of the proposed Project on federal, state, and private

lands. Denbury Resources (Denbury) and their contractors would be responsible for carrying out the methods described in this plan. This Noxious Weed Management Plan is applicable to the construction and operation of the proposed Project.

1.2 GOALS AND OBJECTIVES

The goal of weed management in the Project area is to prevent and control the spread of noxious weeds during the construction and operation of the Project. Denbury will assist federal, state, and local agencies' weed control efforts; comply with requirements designed to prevent the spread of noxious weeds; and implement noxious weed control measures on areas of the Project that are identified to be of special concern.

Success standards outlined in the Reclamation Plan will be used to assess whether revegetation requirements for the Project are being met. Part of successful revegetation includes maintaining native plant communities and a zero tolerance for noxious weed occurrences. Success standards and management goals are designed to be site-specific to each surface-disturbing activity and the surrounding vegetation. Monitoring and treatment both prior to construction and during the operational phase would ensure that these goals are achieved.

2.0 NOXIOUS WEED INVENTORY

Noxious weeds that may potentially occur in the Project area, as identified by the local Weed Districts and BLM offices, are presented in Table 1. In 2015, field biologists from SWCA Environmental Consultants (SWCA) conducted field surveys for noxious weed occurrences within the proposed Project area, in alignment with other resource surveys. The absence of recorded weeds does not infer that areas have no potential for noxious weed occurrences, but that weeds were not detected during 2015 surveys.

All noxious weed occurrences found during 2015 surveys were documented via digital field data forms using geo-referencing tablets. Additionally, Trimble Geo 7X (sub-meter accuracy) Global Positioning System (GPS) units were used to delineate noxious weed occurrences larger than 0.1-acres. Small occurrences under 0.1-acres in size were recorded as individual point features. During field surveys, occurrences of Canada thistle (*Cirsium arvense*), field bindweed (*Convolvulus arvensis*), and Russian olive (*Elaeagnus angustifolia*) were identified.

The presence, distribution, and cover of noxious and invasive weeds in the proposed Project will be assessed prior to all construction activities. Weed surveys will be conducted during the growing season to determine occurrence and abundance within the Project area. Surveys will focus on resources within areas planned for development, including access roads, extra work spaces, and transmission line corridors. Data will be collected using handheld data-logger units and geo-referenced using global positioning system (GPS) locations and delineated shapefiles. Information collected during noxious weed surveys (including species identified, locations, and extent of occurrences within the Project area) will be submitted to the Miles City Field Office and local Weed and Pest Districts. Early identification of existing infestations will help to minimize the spread of noxious weeds with the implementation of preventative measures.

2.1 CANADA THISTLE

Sixty-three occurrences of Canada thistle were identified during the 2015 surveys (Attachment A). All occurrences were found in association with streams, wetlands, ponds, or depressions holding ephemeral hydrology. Sixty-two of these occurrences were isolated patches covering less than 0.1 acre. Two larger occurrences were mapped on Sandstone Creek in the northwest of the project area. The first of these populations was 0.4 acre in size, while the second covered 0.3 acre.

2.2 FIELD BINDWEED

Nine occurrences of field bindweed were identified during the 2015 surveys (Attachment A). Occurrences were generally found in association with upland grasslands and cultivated or disturbed areas. Eight of these occurrences were isolated patches covering less than 0.1 acre. One larger occurrence, approximately 0.1 acre, was mapped on the berm above an unnamed holding pond in the northwestern corner of the project area.

2.3 RUSSIAN OLIVE

Two occurrences of Russian olive were identified during the 2015 surveys (Attachment A). Both were found in association with streams and were isolated patches covering less than 0.1 acre. The first was mapped on Sandstone Creek in the northwest of the project area, while the second was mapped on Waterhole Creek in the central portion of the project area.

3.0 NOXIOUS WEED MANAGEMENT

Noxious weeds are spread by a variety of vectors, including vehicles, construction equipment, livestock, and wildlife. Invasive species management must consider the best available scientific information, updated target population monitoring information, and the effectiveness of control when selecting and implementing a range of complementary and environmentally sound technologies and methods to achieve the desired objectives (NISC 2005). Implementation of preventative measures to control the spread of noxious weeds is the most cost-effective management approach. Noxious weed controls would be implemented in each phase of project development within the construction footprints.

3.1 PREVENTATIVE MEASURES

Prevention is the most cost-effective approach to noxious and invasive weed management. Denbury will assist federal, state, and local agency noxious and invasive weed control efforts; comply with preventative requirements; and implement weed control measures on areas of the Project identified to be of special concern. The following preventative measures would be used to prevent the spread of noxious weeds where ground disturbing activities would occur during construction:

- Denbury would be responsible for the treatment and eradication of any noxious weed populations within the 100-foot-wide construction ROW, ancillary disturbance footprints, and along access roads where improvements would be made. The Fallon,

Carter, and Powder River CWDs, and affected landowners would be responsible for controlling weed infestations present outside of the aforementioned areas.

- Prior to vegetation clearing, the construction ROW and ancillary disturbance footprints would be inspected for noxious weeds by the Environmental Inspector (EI), CWPDs, or a qualified botanist. All noxious weed occurrences would be identified and documented with GPS devices for pre-treatment and post-construction monitoring purposes.
- Preventative measures on private lands would be discussed with individual landowners.
- Prior to being allowed access to the construction ROW and ancillary disturbance footprints, the EI would ensure that vehicles and equipment are free of soil and debris capable of transporting noxious weed seeds, roots, or rhizomes. Vehicles found transporting noxious weed species will not be allowed to enter the Project area.
- Chemical pre-treatment would be used prior to ground clearing activities, as appropriate. Pretreatment methods are discussed in Section 3.2 of this Plan.
- Selective vegetation clearing and soil stripping methods during reclamation would be used to minimize the transport of noxious weed seeds, rhizomes, or roots from infested areas into areas where noxious weeds are not present.
- During the reclamation phase of the proposed project, all areas disturbed by construction would be reseeded. With the exception of permanent aboveground facility footprints, all temporary disturbance areas would be reseeded with an approved seed mix within the proper growing season to ensure appropriate vegetative cover/species and further reduce the establishment of noxious weeds.
- Denbury would verify that all straw bales, mulch, matting, and seed would be certified noxious weed-free before being used on the proposed project.
- All gravel and fill material imported on-site would be source-identified by Denbury to ensure that the originating site is noxious weed-free.

3.2 TREATMENT METHODS

The four primary control categories are mechanical, biological, chemical, and cultural. An integrated approach, typically a combination of control methods, will produce the most effective results. Best management practices (BMPs), such as revegetation paired with active control to manage reoccurrences of noxious plant species (Michels et al. 2013) and continued monitoring of reestablishment of native vegetation and displacement of noxious and invasive weed species are recommended.

Methods used to reduce the spread and establishment of noxious weeds would be determined in coordination with the Fallon, Carter, and Powder River CWDs and affected landowners. Chemical treatments would be used depending on species-specific and site-specific conditions (e.g., proximity to water or wetlands and time of year), and would be coordinated with the BLM Miles City Field Office; Fallon, Carter, and Powder River CWPDs, and affected landowners.

3.2.1 Mechanical Control

Common mechanical control techniques include pulling, cutting, tilling, mowing, and chopping (Attachment B). These techniques, if done often enough, will weaken the weeds by depleting the root reserves and prevent flowering of the plants. Disadvantages of this method are the resources and labor involved the disturbance to the area being treated, and the potential for spreading seeds to other areas. Most noxious weeds are attracted to areas of disturbance, so if not done properly or in combination with other techniques, this method can make the problem worse. An example of poor use of mechanical control is mowing when plants have already seeded; this will spread the seeds. Mowing and cutting should be done multiple times during the growing season, before the plants set any seed.

3.2.2 Chemical Control

Chemical control is through the use of herbicides to either reduce or eliminate the presence of noxious weeds. The decision as to which pesticide to use is based on the target species being controlled; the stage of growth of the plant and current environmental conditions on the ground, i.e., precipitation; other sensitive species nearby; wind speed and direction; and manufacturer's specifications (Attachment B). When using herbicides, Denbury will always follow the manufacturer's recommendations on the label for use conditions and spray rates and appropriate Federal and State regulations.

Herbicide application is an effective means of reducing the size of noxious weed populations. Applications will be controlled to minimize effects on surrounding vegetation. In areas of dense infestation, a broader application will be used and a follow-up seeding program implemented. Supplemental seeding will be based on criteria outlined in the Reclamation Plan. The timing of subsequent revegetation efforts will be based on the life of the selected herbicide.

Only herbicides that are approved for use within treated lands (federal, state, or private) will be used and all herbicides will be applied in accordance with their label requirements. Sensitive areas, as described by the Project Reclamation Plan, will be treated with the using the following BMPs. If weeds targeted for herbicide treatments are found in the vicinity of sensitive areas, proper buffers established in coordination with the BLM and local agencies will be used to prevent the spread of herbicides to these areas. If weeds are found in sensitive areas, cultural and/or mechanical controls will be implemented. In areas where noxious weeds may be interspersed with native vegetation, the herbicide application method will be adapted to affect only targeted weed species to preserve and retain native plant communities.

BLM Manual 9011 (Chemical Pest Control) outlines the policies, and BLM Handbook H-9011-1 (Chemical Pest Control) outlines the procedures, for use of herbicides on public lands. An approved Pesticide Use Proposal (PUP) is required to apply chemical herbicide (Attachment B). All herbicide applications on BLM-administered public lands are required to be applied by a certified commercial applicator(s) and all herbicides used must be from the current list of herbicides approved for application on BLM-administered lands (BLM 2015).

Spot spraying applies herbicide to the foliage of weed species, avoiding contact with the surrounding foliage. Spot sprays can be applied with either backpack sprayers or by operating a handgun from a line connected to a tractor mounted sprayer. Overall broadcast spraying is done with a boom sprayer. Irregular spray applications can be avoided by the use of flagging tape, foam markers, or the use of an appropriate dye. To apply the herbicides at the recommended rate the equipment must be calibrated and in proper working order. An overall broadcast spray is recommended for treating large infestations.

The effects to special status species (see BLM Manual 6840 Special Status Species) will be considered when designing herbicide treatment programs. A selective herbicide and a wick or backpack sprayer will be used to minimize risks to special status plants. Vegetation will not be treated with herbicide during time-sensitive periods (e.g., nesting and migration, sensitive life stages) for special status species in the treatment area. Other treatment methods (i.e., cultural or mechanical treatment) will be implemented during these periods.

3.2.2.1 Pre-construction Herbicide Treatment

Prior to construction activities that disturb soil and vegetation, noxious weeds would be treated with chemical herbicides at the appropriate time dependent on the targeted species (e.g., spring, summer, or fall spraying). The uses of herbicides that break down and detoxify relatively rapidly are necessary to prevent adverse effects on germination and growth of reseeded species. Only approved, short-lived herbicides would be used for pre-treatment of noxious weeds. Only approved herbicides would be used to control noxious weeds near water, wetlands, and riparian areas.

Pre-construction treatment would be conducted prior to any clearing of vegetation to reduce the spread of noxious weeds by equipment used during clearing. The treatment method applied would vary depending on site-specific conditions and the type of species encountered. Methods used to reduce the spread and establishment of noxious weeds would be discussed with the affected landowners, the BLM, and applicable CWD.

3.2.2.2 Post-construction Herbicide Treatment

Post-construction treatment of noxious weeds, if required, would likely require use of more persistent herbicides on upland sites that are more than 100 feet from waterbodies, wetlands, or riparian areas. As discussed in Section 3.2.2, only approved herbicides would be used to control noxious weeds near waterbodies, wetlands, and riparian areas.

Supplemental seeding would be in accordance with criteria presented in the Project Reclamation Plan. The timing of subsequent revegetation efforts would be based on the life of the selected herbicide. In areas of dense infestation, a broader application may be used and a follow-up seeding program implemented.

3.2.3 Biological Control

Biological control (biocontrol) is done by the introduction of animals (usually insects), fungi, or diseases to the plant in order to either weaken it or kill it entirely. The organism used usually comes from the native range of the target species and will commonly only affect that species or sometimes members of the same family. Such is the case with thistles, where some

of the biocontrol species affect more than one species. The use of biocontrol methods will require the permission of both the state and federal authorities, usually the USDA. The intent of biocontrol is not to eradicate weed occurrences, but to reduce the density and vigor of known occurrences to manageable levels that may be controlled through the application of additional control measures, if necessary (Michels et al. 2013). Most sites occur in disturbed areas along roadsides or inundated with other noxious and invasive weed species. Revegetation of native grasses and forbs likely would be effective in preventing the reestablishment of weed species of controlled sites and provide a healthy plant community and habitat.

3.2.4 Cultural Control

To perform cultural control of invasive weeds, the habitat surrounding the area or the area of infestation itself is manipulated. This includes manipulation of vegetation canopy and structure as well as composition around an area of noxious weeds that are likely shade intolerant. Cultural control methods can also include the use of mechanical control by using a tractor to till, mow or cut, and irrigate an area to reduce the seed bank, thereby allowing for native species to be planted in an effort to outcompete the noxious weeds.

Another method is the use of grazing animals, usually goats and sheep, to control invasive weed populations. The use of other livestock can be beneficial, but cattle and horses are often poisoned by many invasive species where goats and sheep are tolerant. This method will usually need to be done repeatedly over the course of several years to be effective. Rarely will the animal eat the entire plant, most of the time; the damage is done to the rosette or the flower of the plant. As is the case with most of mechanical, biological, and cultural methods, the best results will be in combination with an appropriate chemical control program.

Prescribed fire or controlled burns can reduce invasive plant material and stimulate native species. Following local and federal regulations concerning prescribed fires, this treatment is accomplished by burning the vegetative material. The burns are done under precise weather and fuel conditions guided by local ordinances and planned and organized by trained fire crews. Burning is normally conducted in the spring or fall and can kill or severely reduce the intensity of noxious weeds.

3.3 EDUCATION

Information regarding noxious weed identification, management, and impacts on livestock, wildlife, and special status species would be provided to all project personnel. Additionally, workers would be informed on the critical importance of preventing the spread of noxious weeds in areas not infested, and controlling the proliferation of weeds already present. The importance of adhering to measures to prevent the spread of noxious weeds (e.g., use of permitted travel lanes and proposed access roads; preventive measures that control the collection of soil and plant seeds on vehicles prior to entering the proposed construction areas; and quickly identifying new infestations of noxious weeds) would be emphasized.

3.4 MONITORING

Annual post-construction vegetation monitoring would be conducted during the peak of the growing season for five years. Monitoring would be conducted within all construction disturbance areas regardless of surface ownership. All new noxious weed occurrences found during annual monitoring within areas disturbed by the proposed project would be treated, as necessary. If after three years revegetation is not successful, a remedial revegetation plan would be developed and implemented in consultation with the appropriate agencies and landowners.

Data collected during monitoring events would include the following:

- Identification of the noxious weed species present by common and scientific name;
- Location information (GPS documentation and accompanying map products);
- Extent of the infestation; results of previous control measure implemented (if any);
- Recommendations for further control (if needed).

Spatial estimates would be made for the entire population size; comparing disturbed and adjacent areas, and would include the range of species cover and density values. Consultation with the BLM Miles City Field Office and the Fallon, Carter, and Powder River CWDs will take place to determine the most appropriate control measures. All noxious weed populations would be document with GPS devices. All post-construction monitoring results would be submitted in an annual report to the appropriate agencies.

4.0 REFERENCES

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ATTACHMENT A

NOXIOUS WEED OCCURRENCES*

* The absence of recorded weeds does not infer that areas have no potential for noxious weed occurrences, but that weeds were not detected during 2015 surveys.

Common Name	Species	USDA/Plants Code	Occurrence Size (Acres)	Latitude	Longitude
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2800	-104.1686
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2940	-104.0739
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2948	-104.0734
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2955	-104.0753
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2958	-104.2290
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2959	-104.0745
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2973	-104.0750
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2975	-104.0757
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.2986	-104.0864
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3020	-104.0813
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3025	-104.0810
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3030	-104.2337
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3033	-104.0831
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3038	-104.2343
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3067	-104.0848
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3072	-104.0840
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3077	-104.0847
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3079	-104.0856
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3084	-104.0860
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3088	-104.2396
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3103	-104.0520
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3114	-104.0840
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3166	-104.0581
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3170	-104.0594
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3209	-104.1405
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3298	-104.0844
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3320	-104.1328
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3320	-104.0806
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3339	-104.0902
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3409	-104.1428
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3413	-104.1465
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3421	-104.1482
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3465	-104.2102
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3513	-104.2582
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3534	-104.2588
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3547	-104.2597
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3562	-104.2526
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3562	-104.2529
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3562	-104.2529

Common Name	Species	USDA/Plants Code	Occurrence Size (Acres)	Latitude	Longitude
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3576	-104.2578
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3690	-104.2429
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3690	-104.2429
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3695	-104.2427
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3697	-104.2407
Canada thistle	<i>Cirsium arvense</i>	CIAR4	0.3	46.3700	-104.2208
Canada thistle	<i>Cirsium arvense</i>	CIAR4	0.4	46.3715	-104.2351
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3725	-104.2450
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3743	-104.2018
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3744	-104.2055
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3767	-104.2430
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3776	-104.1406
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3812	-104.1442
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3831	-104.2124
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3833	-104.1896
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3836	-104.1897
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3864	-104.2232
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3880	-104.2260
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3887	-104.1993
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3926	-104.2484
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3930	-104.2495
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3930	-104.2501
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3946	-104.1955
Canada thistle	<i>Cirsium arvense</i>	CIAR4	<0.1	46.3987	-104.2012
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.2914	-104.1146
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3028	-104.2336
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3140	-104.0546
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3418	-104.1388
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3655	-104.1359
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3720	-104.2532
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3836	-104.1897
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	<0.1	46.3887	-104.1993
Field bindweed	<i>Convolvulus arvensis</i>	COAR4	0.1	46.3895	-104.2689
Russian olive	<i>Elaeagnus angustifolia</i>	ELAN	<0.1	46.3413	-104.1465
Russian olive	<i>Elaeagnus angustifolia</i>	ELAN	<0.1	46.3715	-104.2695

ATTACHMENT B

SPECIES CONTROL OPTIONS*

*Potential control options for noxious species found during 2015 field surveys. The following information is provided as a resource only and is not intended to limit control methods.

Field bindweed

Field bindweed is a creeping, viney, deep-rooted perennial with prostrate stems that grow up to 6 feet long (Figure 1). This plant has an expansive root system (up to 20 feet deep) that assists in propagation. Stems are capable of twining around other plants or trail along the ground. The arrowhead-shaped leaves are 0.5 to 2.0 inches long and flowers are bell- or trumpet-shaped, white to pink in color, and about 1 inch long. This species flowers from June through September and a single plant is capable of producing up to 550 seeds with 90% viability (Penn State Extension College of Agricultural Sciences 2014). These seeds can remain viable in the soil for up to 40 years (CDA 2014). Field bindweed commonly invades cultivated fields, orchards, gardens, pastures, abandoned fields, and roadsides.



Figure 1. Field bindweed

Control Options

To successfully manage field bindweed, containment and persistence in controlling existing stands is necessary in order to exhaust the root system and deplete the soil seed bank. This weed needs to be continually stressed, forcing it to exhaust root nutrient stores and eventually die. Of all control methods, prevention is most important. Healthy pastures and rangeland should be maintained and the property should be continually monitored for new infestations. A healthy cover of desirable perennial plants will assist in discouraging field bindweed establishment (CDA 2014).

Mechanical Control

Cutting, mowing, or pulling has a negligible effect unless the plants are cut below the surface in the early seedling stage (CDA 2014). Well-established populations have a large seed bank in the soil that can remain viable for over 40 years.

Chemical Control

The most effective herbicide application is systematic herbicides which will be transported to the roots and kill the plant (Table 1). This can be done when the plant is in bud or early bloom stage. Contact application of herbicides will kill the top growth, but not affect the root system. If in a severe drought, do not apply the herbicides as the plant will be dormant and

translocation to the roots is negligible. Effective herbicides include: Tordon 22K, Clarity, Roundup Ultra, and 2,4-D. Ideal timing of herbicide application is May through August with some cases of early September for application of picloram and 2,4-D (CSU Extension 2014). Chemical control of field bindweed generally requires a multiple-year approach.

Table 1. Recommended Herbicides to Control Field Bindweed

Trade Name	Active Ingredient	Application Rate*	Application Timing	Notes
Tordon 22K	Picloram	1 qt/acre	Just after full-bloom and/or fall.	Restricted-use herbicide cannot be used where there is a potential for water contamination. Add non-ionic surfactant @ 0.32 oz/gal water or 1 qt/100 gal water.
Clarity + 2,4-D amine	Dicamba+ 2,4-D amine	1 qt/acre	Just after full-bloom and/or fall.	Add non-ionic surfactant @ 0.32 oz/gal water or 1 qt/100 gal water.
Roundup Ultra	Glyphosate	4-5 qts/acre	Just after full-bloom and/or fall.	Add non-ionic surfactant @ 0.32 oz/gal water or 1 qt/100 gal water.

* Rates shown are approximate; read label for exact rates. The herbicide label is the law.

Biological Control

The bindweed gall mite (*Aceria mahlerbae*) has proven to be effective in reducing field bindweed infestations and is considered an option for large infestations (CDA 2014). This microscopic mite feeds on field bindweed and other related morning glory species. Mites are released in the cooler part of the day on non-irrigated sites. If this method is effective, the leaves will fold in half or appear twisted or crumpled (CSU Extension 2014).

Cultural Control

Shading field bindweed from shrubs and trees reduces growth, especially if bindweed is not allowed to climb above the foliage of these plants. Establishment of selected native grasses (E.g. Bluebunch wheatgrass, Western wheatgrass, Indian ricegrass, and Sandberg bluegrass) can also be an effective cultural control of field bindweed as is maintaining healthy pastures and preventing bare spots caused by overgrazing. Bare ground is prime habitat for field bindweed invasions.

References

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Canada thistle

Canada thistle is native throughout Europe and northern Asia and is a perennial broadleaf weed. Its rhizomes and roots can extend up to 17 feet horizontally and up to 20 feet deep (Figure 2). Plants can grow 2 to 5 feet high with each flower head producing roughly 50 seeds with an average stem containing roughly 12 to 14 flowers. Flowering occurs from June to October with pollination occurring primarily through wind, but insects are attracted to the scent of the flowers (Penn State Extension College of Agricultural Sciences 2014). Seeds commonly germinate beginning in late spring and continue through the fall with 86°F considered the best temperature for germination.



Figure 2. Canada thistle

Control Options

Because of its vigorous rhizomatous growth and abundant seed production, it is recommended that a combination of control methods be considered for best results. Prevention is the most important strategy. This can be achieved by maintaining healthy natural plant communities and immediately treating new infestations. Established infestations need to be continually stressed. The interruption of seed production and root propagation will weaken the plants by depleting the energy reserves in the roots. Management options become limited once plants begin to produce seeds (Colorado Department of Agriculture [CDA] 2014).

Mechanical Control

Due to Canada thistle's extensive root system, hand-pulling and tilling will create root fragments and stimulate the growth of new plants (CDA 2014). Repeated mowing will assist in weakening the plants and deplete the energy reserves stored in the roots, which will impact seed production and destroy the current year's growth. Mowing can be effective if done every 10 to 21 days throughout the growing season (CDA 2014; Penn State Extension College of Agricultural Sciences 2014). Mowing should be done early in the growing season before plants flower and set seed. Combining mowing with chemical control methods will further enhance Canada thistle control (CDA 2014).

In some instances, mowing may not be a viable control option for Canada thistle. Examples include areas that are known to be inhabited by special status species protected by the ESA. Additionally, wetland areas are protected through federal regulations such as Section 404 of the Clean Water Act of 1977, which regulates the discharge of dredged or fill material into waters of the United States, including wetlands. Therefore, mechanical control options causing disturbance to soils in close proximity to wetland habitats may not be a viable or environmentally responsible option.

Chemical Control

Table 2 includes recommendations for herbicides that can be used for control of Canada thistle (CDA 2014; Colorado State University [CSU] Extension 2013). Repeat treatments may be necessary for up to an additional 3 years until root nutrient stores are fully depleted. Depending on the herbicide used, treatments can be completed either in the spring at the pre-bud growth stage or in the fall to control regrowth. Always read, understand, and follow the label directions; the herbicide label is the law. Chemical control of established infestations is more effective when combined with other treatment options such as mechanical or cultural control methods.

Table 2. Recommended Herbicides to Control Canada Thistle

Trade Name	Active Ingredient	Application Rate*	Application Timing	Comments
Milestone	Aminopyralid	5-7 oz/acre	Apply in spring at the pre-bud growth stage until flowering and/or to fall regrowth.	Add 0.25% v/v non-ionic surfactant (equivalent to 0.32 oz/gal water or 1 qt/100 gal water).
Perspective	Aminoclopyrachlor + chlorsulfuron	5.5 oz/acre	Apply in spring from rosette to flower bud stage and/or fall regrowth.	Applications greater than 5.5 oz/acre exceeds the threshold for selectivity. Do not treat in the root zone of desirable trees and shrubs. Add 0.25% v/v non-ionic surfactant

Trade Name	Active Ingredient	Application Rate*	Application Timing	Comments
Confront	Clopyralid + Triclopyr	3 pints product/acre	Apply from rosette to flower bud stage and/or fall regrowth.	Add 0.25% v/v non-ionic surfactant.
Tordon 22K	Picloram	1 qt/acre	Spring after all shoots have emerged, rosette to early bud growth stages; or fall.	Do not apply near trees or where soils have rapid permeability or water level is high. Add 0.25% v/v non-ionic surfactant non-ionic surfactant.
Transline	Clopyralid	0.67-1.33 pints/acre	Spring after all shoots have emerged, rosette to early bud growth stages; or fall.	May need re-treatment for 1 to 3 years.
Telar XP	Chlorsulfuron	1 oz/acre	Spring bolting to bud growth stages; or fall.	Fall applications most consistent results. Add non-ionic surfactant at 0.25% v/v; may need retreatment 1 to 2 years.
Banvel, Vanquish, Clarity	Dicamba	2 qts/acre	Spring rosette growth stage; or fall.	Fall applications most consistent results; may need re-treatment 2 to 4 years.

* Rates shown are given as a guideline only; read and follow label for exact rates.

Further chemical control options are available and may already be in use on WAFB. If an effective chemical control plan has been established, it is recommended that monitoring results are regularly revisited to assess treatment success. If results are not meeting control goals then treatment options should be revisited.

Biological Control

Cattle, goats, and sheep will graze on Canada thistle when plants are young and succulent in the spring. Grazing will stress plants and increase susceptibility to chemical treatments in the fall. Grazing will reduce tall growth and reproduction using a rotational grazing pattern so as to not negatively affect native vegetation. If an area is overgrazed however, that will favor the spread of Canada thistle. Best time to graze the area will be May and June.

Two insect species are available for use to control Canada thistle, but results have shown limited control (CDA 2014). Stem weevil (*Ceutorhyncus litura*) is a weevil currently being used for Canada thistle control in Colorado and Wyoming. The female deposits eggs on the leaves of Canada thistle plants in early spring and larvae will bore into the crown. This damage causes stress to the plants, but may not be lethal. Stem gall fly (*Urophora cardui*) is also currently being used as a biocontrol agent in Colorado and Wyoming. The female lays eggs on the apical meristem of developing shoots and resulting larvae burrow into the plant triggering large galls to form. This stress can reduce reproductive output and limit seed production (CSU Extension 2013).

The most effective biological control agent trialed to date is Canada thistle rust (*Puccinia punctiformis*). Unlike many classical biological control agents that limit or control the spread of an infestation, the Canada thistle rust fungus specifically targets one host and has the potential to significantly decrease infestations. In past trials, control of Canada thistle showed a range from 45% reduction of thistles over 5 years to 100% after 18 months (CDA 2014). Effective collection and distribution methods are under development, but studies have shown that the weevil (*Ceratapion onopordi*) induces systemic infections in the year following weevil infestation by transmitting spores of the rust fungus to Canada thistle plants (Wandeler et al. 2008).

Cultural Control

Prevention is the best control strategy for Canada thistle and a robust monitoring program will detect new infestations for immediate treatment (CDA 2014). Maintaining healthy native plant communities and preventing bare ground caused by overgrazing or disturbance will help control spread of Canada thistle. Establishment of select grasses can be an effective control. Perennial forage crops and winter-annual cereal crops compete very effectively with Canada thistle and can inhibit its emergence (Penn State Extension College of Agricultural Sciences 2014). This is due to the susceptibility of Canada thistle seedlings to shading. Seedlings will exhibit greater vigor without competition for light.

Controlled burning of large areas infested with Canada thistle can weaken plants and destroy stored energy reserves. For successful control, burns must continue for up to 3 years and be combined with fall herbicide application. Restoration of native plant communities will likely be needed to reduce further invasive species colonization.

References

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Russian olive

Russian olive is a perennial tree or shrub that is native in Europe and Asia (Figure 3). This species can reproduce by seed or the plants' extensive root system which sprouts root suckers frequently. Seeds are readily spread by birds and can remain viable for up to 3 years. Spring moisture and alkaline soils tend to favor seedling growth. The tree can reach up to 30 feet in height with branches that have 1- to 2-inch thorns. The alternate leaves are linear and 2 to 3 inches long. The lower surface is silvery white, while the upper surface is light green. The small light yellow flowers are born in clusters from May through June. Fruits mature from September to November.



Figure 3. Russian olive.

Control Options

The key to effective control of Russian olive is preventing establishment of the trees or shrubs (CDA 2014). If plants are already present, control options include mechanical mowing, cut-stump treatments, or basal bark treatments. These treatment options depend on the size and location of the plant.

Mechanical

Saplings can be pulled or cut with a brush-cutter and mature trees can be girdled or cut with a chainsaw, however this will often lead to sprouting from the roots. Stump excavation without removal of the roots can also result in sprouting. Treating cut stumps with an herbicide can eliminate this problem. Saplings are most sensitive to mechanical treatment (CDA 2014).

Chemical

Table 3 includes recommendations for herbicides that can be applied to range and pasturelands for control of Russian olive.

Table 3. Recommended Herbicides to Control Russian Olive

Trade Name	Active Ingredient	Application Rate*	Application Timing	Notes
Garlon 4, Remedy	Triclopyr	Undiluted	Apply to the cambial layer of the tree immediately after the cut-stump treatment.	
Habitat, Arsenal	Imazapyr	8 to 12 fl oz/gallon	Apply to the cambial layer of the tree immediately after the cut-stump treatment.	
Habitat, Arsenal	Imazapyr	4 to 6 pt/acre	Broadcast spray individual trees; low or high volume spray.	

* Rates shown are approximate; read label for exact rates. The herbicide label is the law.

Biological

Tubercularia canker is a biological control agent for Russian olive (CDA 2014). It overwinters on infected stems and spreads via rain-splash, herbivory, or pruning implements to open wounds in the bark. Infected tissue becomes discolored or sunken and entire stems may become girdled or killed. Over time, this disease can deform or kill stressed Russian olive plants. Mature goats have also been used to selectively graze seedlings and young trees (Bureau of Land Management 2013).

Cultural

One cultural control method is to remove Russian olives and replace them with native trees. It is important to prevent the establishment of new infestations by removing any Russian olive saplings or seedlings before they can mature (CDA 2014).

References

Colorado Department of Agriculture (CDA). 2014. Noxious weed species. Available online at <https://www.colorado.gov/pacific/agconservation/noxious-weed-species>. Accessed December 2014.

ATTACHMENT C

PESTICIDE USE PROPOSAL FORM

Prior to the initial application of chemical herbicides on public land, a 3-year PUP would be prepared and submitted to the BLM Authorized Officer. A revised PUP would be submitted if control measures are needed beyond the 3-year PUP time period. Following herbicide application, a Pesticide Application Record (PAR) would be submitted to the BLM Miles City Field Office and Fallon, Carter, and Powder River CWD supervisors.

Herbicide Application and Handling

The use, handling, storage, and disposal of herbicides would be performed in compliance with all federal and state laws. Prior to herbicide application, Denbury would complete PUPs and obtain the required permits from the BLM Miles City Office, and Fallon, Carter, and Powder River CWDs, as appropriate. Herbicide application would be performed by the operations personnel or an independent, licensed contractor in accordance with all applicable laws and regulations. The contractor would either prove knowledge in noxious weed identification, or be accompanied by a qualified botanist to ensure that the appropriate species are treated on-site.

All guidelines by the Environmental Protection Agency (EPA) herbicide label instructions would be strictly followed. Applications of herbicides would not be permitted when the instructions on the herbicide label indicate conditions that are not optimal. Herbicide application would be suspended if the following conditions exist.

- Wind velocity exceeds 20 miles per hour;
- Snow or ice covers the foliage of noxious weeds; or
- Precipitation is occurring or imminent.

Vehicle-mounted sprayers (e.g., handgun, boom, and injector) would be used primarily in open areas that are readily accessible by vehicle. Hand application methods (e.g., backpack spraying) that target individual plants would be used to treat small, scattered noxious weed populations in rough terrain. Herbicide application would follow the following restrictions:

- Boom and hand gun sprayers would not be used within 25 feet of surface water;
- Broadcast backpack spraying would not occur within 10 horizontal feet of water;
- Only wipe application (or hand-directed spray using a backpack sprayer) would be allowed within 10 horizontal feet of surface water; and
- Herbicides would not be mixed in an area where accidental spill could enter a waterbody.

Fertilizers, lime, or mulch would not be used in wetlands unless required by agencies.

Herbicides would be transported to the project site with the following provisions:

- Concentrate would be transported only in containers in a manner that would prevent tipping or spilling and in a compartment that is isolated from food, clothing, and safety equipment; and
- Mixing would only be conducted on-site and more than 200 feet from open or flowing water, wetlands, or other sensitive resources.

Worker Safety and Spill Reporting

All herbicide contractors would obtain and have readily available copies of the appropriate USEPA Material Safety Data Sheets (MSDS) for the herbicides being used. Herbicide spills would be reported in accordance with all applicable laws and requirements.

Herbicide Use

The use of herbicides would comply with the federal and state laws governing their proper use and storage, and disposal. Further, their use would only occur within the purview of the regulations set forth by the Secretary of the Interior.

The following is the sequence of events to be followed for using herbicides on BLM administered lands:

- An on-site reconnaissance would occur between the company personnel, or their contractor, and CWD personnel certified in pesticide application. A treatment plan would be formulated.
- The primary species targeted for control on BLM and private lands would include those presented on the Montana Noxious Weed list as well as the additional county-specific species of concern (see Table 1).
- The loss of special status plant species and their associated habitats from weed control measures during project maintenance would be avoided by consultation between the special status plant species jurisdictional agency and weed control specialists.
- The 3-year PUP form would be submitted by the permit holder to the BLM Miles City Field Office certified pesticide applicator (Authorized Officer).
- The permit holder would be notified by this office of approval of the PUP and be furnished a copy of the document with any changes noted and explained.
- Any special conditions, such as sign posting requirements or notice to livestock grazers, would be noted.
- The BLM Miles City Field Office would be notified at least 72 hours prior to pesticide application so that application operations can be inspected.
- All herbicides, both restricted use and nonrestrictive use, would be applied only by personnel certified in the use of these herbicides or under the direct supervision of certified applicators. A PAR form would be completed within 24 hours of ceasing herbicide application. The PAR would be submitted by the permit holder to the certified BLM Miles City Field Office certified pesticide applicator and the Fallon, Carter, and Powder River CWD supervisors, within seven days of completion of field treatment operations for the season.

UNITED STATE DEPARTMENT OF THE INTERIOR

BUREAU OF LAND MANAGEMENT

PESTICIDE USE PROPOSAL

STATE:

COUNTY:

FIELD OFFICE:

DURATION OF PROPOSAL:

LOCATION:

ORIGINATOR – NAME:

ORIGINATOR – COMPANY:

ORIGINATOR – CONTACT INFORMATION:

DATE:

PROPOSAL NUMBER:

EA REFERENCE NUMBER:

DECISION RECORD (DR) NUMBER:

.....

I. APPLICATION INFORMATION – (Including mixtures and adjuvants):

1. TRADE NAME(S):
2. COMMON NAME(S):
3. EPA REGISTRATION NUMBER(S):
4. MANUFACTURER(S):
5. METHOD OF APPLICATION:
6. MAXIMUM RATE OF APPLICATION – AS STATED ON THE LABEL:
 - a. Formulated Product:
 - b. Pounds Active Ingredient or Acid Equivalent:
7. INTENDED RATE OF APPLICATION:
 - a. Formulated product:
 - b. Pounds Active Ingredient or Acid Equivalent:
8. APPLICATION DATE(S):
9. NUMBER OF APPLICATIONS:

II. **PEST** [List specific pest(s) and reason(s) for the proposed application of the pesticide]:

III. **DESIRED RESULTS OF THE APPLICATION – LINKED TO THE OBJECTIVES OF THE APPLICATION:**

IV. **APPLICATION SITE DESCRIPTION:**

1. ESTIMATED NUMBER OF ACRES:
2. GENERAL DESCRIPTION (Describe land type or use, size, stage of growth of target species, soil characteristics, and any additional information that may be important in describing the area to be treated.)

V. **SENSITIVE ASPECTS AND PRECAUTIONS** (Describe sensitive areas – marsh, endangered, threatened, candidate, and sensitive species habitat – and distance to application site. List measures to be taken to avoid impact to these areas):

VI. **NON-TARGET VEGETATION** (Describe potential immediate and cumulative impacts to non-target pests in Project area as a result of the pesticide application. Identify any planned mitigation measures that will be employed – BE GENERAL, SPECIFICS DISCUSSED IN THE EA):

VII. **INTEGRATED PEST MANAGEMENT PRACTICES CONSIDERED IN THE OVERALL PROJECT:**



VIII. **SIGNATURES:**

1. Pesticide Use Proposal's Originator: _____ Date: _____
 - a. Company: _____
2. Certified Pesticide Applicator: _____ Date: _____
 - a. Printed Name: _____
 - b. Address: _____
 - c. License Number: _____
 - d. Certifying Organization: _____
3. Field Office Weed and Pest Coordinator: _____ Date: _____
4. Field Office Manager: _____ Date: _____

5. BLM State Weed and Pest

Coordinator: _____ Date: _____

6. Deputy State Director: _____ Date: _____

- Concur or Approved
- Not Concur or Disapproved
- Concur or Approved With Modifications

- Any changes (modifications) to this proposal by the state pesticide Coordinator will be listed below or in an attached memo to the manager requesting approval from the Deputy State Director

Attachment 10

Sample ID	Latitude	Longitude	Topsoil De	Milepost	Depth	Zone
126	46.30035	-104.19			1	3
125	46.30206	-104.189	3		1	3
124	46.30376	-104.187	3		1	3
123	46.30546	-104.185	2		1	3
122	46.30717	-104.184	4		1	3
121	46.30887	-104.182	4		1	3
120	46.31058	-104.181	4		1	3
119	46.31229	-104.179	4		1	3
118	46.31403	-104.177	3		2	3
117	46.31576	-104.176	5		2	6
116	46.3175	-104.174	5		2	6
115	46.31914	-104.172	3		2	3
114	46.32013	-104.17	8		2	6
113	46.31945	-104.167	3		2	3
112	46.31878	-104.165	3		3	3
111	46.3181	-104.162	3		3	3
110	46.31743	-104.159	4		3	3
109	46.31698	-104.156	7		3	6
108	46.31684	-104.153	6		3	6
107	46.31709	-104.151	6		3	6
106	46.31697	-104.148	7		3	6
105	46.31705	-104.145	7		3	6
104	46.31725	-104.142	5		4	6
103	46.31719	-104.139	7		4	6
102	46.31712	-104.136	4		4	3
101	46.31723	-104.133	3		4	3
100	46.31728	-104.13	4		4	3
99	46.31728	-104.127	4		4	3
98	46.31631	-104.124	5		4	6
97	46.31527	-104.122	7		5	6
96	46.31441	-104.119	4		5	3
95	46.31354	-104.117	6		5	6
94	46.31268	-104.114	4		5	3
93	46.3121	-104.111	6		5	6
92	46.31174	-104.108	7		5	6
91	46.31119	-104.105	8		5	9
90	46.31048	-104.102	6		6	6
89	46.31005	-104.1	6		6	6
88	46.31006	-104.097	3		6	3
87	46.30926	-104.094	5		6	3
86	46.30831	-104.091	6		6	6
85	46.30736	-104.089	5		6	6
84	46.30667	-104.086	7		6	6
83	46.30571	-104.083	4		7	3
82	46.30466	-104.081	7		7	6
81	46.30464	-104.078	8		7	6

80	46.30461	-104.075	4	7	3
79	46.30425	-104.072	4	7	3
78	46.30219	-104.072	3	7	3
77	46.30015	-104.072	5	7	6
76	46.29809	-104.072	3	8	3
75	46.29692	-104.071	5	8	6
74	46.29665	-104.068	4	8	3
73	46.29642	-104.065	7	8	6
72	46.2962	-104.062	6	8	6
71	46.29585	-104.059	6	8	6
70	46.29504	-104.057	5	8	6
69	46.29359	-104.055	5	9	6
68	46.29274	-104.052	12	9	9
67	46.29287	-104.049	3	9	3
66	46.29264	-104.046	12	9	12
65	46.29225	-104.043	12	9	12
64	46.29198	-104.04	9	9	9
63	46.2917	-104.037	15	9	12
62	46.29144	-104.035	4	9	6
61	46.29124	-104.032	4	9	3
60	46.29118	-104.029	6	10	6
59	46.29103	-104.026	14	10	12
58	46.28931	-104.024	12	10	12
57	46.28758	-104.023		10	9
56	46.28586	-104.021	6	10	6
55	46.28415	-104.019	12	11	12
54	46.28353	-104.017	7	11	6
53	46.28296	-104.014	4	11	6
52	46.28238	-104.011	10	11	9
51	46.28179	-104.008	12	11	12
50	46.28062	-104.006	6	11	6
49	46.27976	-104.003	12	11	9
48	46.27986	-104	1	12	3
47	46.27997	-103.997	6	12	6
46	46.28009	-103.994		12	6
45	46.27896	-103.992	3	12	3
44	46.27759	-103.99	4	12	3
43	46.27682	-103.987	3	12	3
42	46.27632	-103.984	5	12	6
41	46.27581	-103.981	6	13	6
40	46.27444	-103.979	12	13	12
39	46.27262	-103.979	12	13	12
38	46.2719	-103.976	0	13	3
37	46.27145	-103.973	3	13	3
36	46.27099	-103.97	12	13	9
35	46.27053	-103.967	3	13	6
34	46.27008	-103.964	12	14	12

33	46.26962	-103.961	12	14	12
32	46.26916	-103.959	3	14	3
31	46.26871	-103.956	3	14	3
30	46.26825	-103.953	4	14	3
29	46.26801	-103.95	3	14	3
28	46.26616	-103.949	4	14	3
27	46.26416	-103.948	4	15	3
26	46.26211	-103.948	6	15	6
25	46.26008	-103.948	12	15	9
24	46.25807	-103.949	7	15	6
23	46.25618	-103.95	3	15	3
22	46.25413	-103.95	6	15	6
21	46.25212	-103.949	3	15	3
20	46.2501	-103.95	1	16	3
19	46.24805	-103.95	5	16	6
18	46.24599	-103.95	12	16	12
17	46.24394	-103.95	12	16	12
16	46.24189	-103.95	12	16	12
15	46.23988	-103.95	12	16	12
14	46.238	-103.948	3	16	6
13	46.23612	-103.947	7	17	6
12	46.23425	-103.946	12	17	12
11	46.23238	-103.945	12	17	12
10	46.23057	-103.943		17	12
9	46.22876	-103.942		17	9
8	46.22692	-103.941		17	9
7	46.225	-103.94		17	9
6	46.22298	-103.939		18	9
5	46.22104	-103.94		18	12
4	46.21923	-103.942	12	18	12
3	46.21746	-103.943	12	18	12
2	46.21541	-103.943	12	18	12
1	46.21336	-103.943	5	18	6