APPENDIX I – UNANTICIPATED DISCOVERIES PLAN

Unanticipated Discoveries Plan

North Dakota CarbonSAFE: Project Tundra
Oliver County, North Dakota

Prepared for
Minnkota Power Cooperative, Inc.

June 2023

4300 MarketPointe Drive, Suite 200
Minneapolis, MN 55435
952.832.2600
www.barr.com

Unanticipated Discoveries Plan

Tundra Pipeline Project

Contents

List of Tables

List of Attachments

Abbreviations

APE	Area of Potential Effects
MPC	Minnkota Power Cooperative, Inc.
NDCC	North Dakota Century Code
NHPA	National Historic Preservation Act
NRHP	National Register of Historic Places
Project	North Dakota CarbonSAFE: Project Tundra
SHPO	State Historic Preservation Officer
UDP	Unanticipated Discoveries Plan

1 Introduction

This Unanticipated Discoveries Plan (UDP) provides the procedures that Minnkota Power Cooperative, Inc. (MPC) will implement in the event cultural resources and/or human remains are identified during construction of the Tundra Pipeline Project (Project).

Unanticipated discoveries typically occur when previously undetected cultural resources are exposed during construction or other permitted surface disturbing activities, but after the federal agency has completed the Section 106 process.

The purpose of this UDP is to properly identify and protect any cultural resource materials such as artifacts, sites, human skeletal remains, or any other cultural resources eligible, or potentially eligible, for listing in the National Register of Historic Places (NRHP) that are discovered during construction of the Project. This UDP provides guidance to MPC and their contractors so they can:

- Comply with any applicable federal and state laws regarding cultural resources;
- Describe to regulatory agencies, review agencies, and Tribal Historic Preservation Offices (THPOs) the procedures MPC will follow to prepare for and deal with unanticipated discoveries; and
- Provide direction and guidance to Project personnel for the proper procedures to be followed should an unanticipated discovery occur.

2 Roles and Responsibilities

The following roles and responsibilities have been defined for this UDP.

- **MPC Environmental Specialist**: MPC Representative. Responsible for Notifying the State Historic Preservation Office (SHPO) in the event of an accidental discovery.
- **State Historic Preservation Officer (SHPO)**: State-appointed official responsible for consulting with Federal, State, and local governments in matters of historic preservation and NRHP eligibility pursuant to Section 106 of the NHPA.
- **SHPO-permitted Archaeological Consultant**: Qualified archaeologist as defined in 36 CFR Part 61 and in receipt of the Annual Archaeological Permit required by North Dakota Century Code (NDCC) section 55-03-01.
- **Archaeological Monitor**: SHPO-permitted Archaeological Consultant on-site during construction to monitor ground disturbing activities for the presence of cultural resources. Has authority to stop construction to further investigate potential resources.
- **Supervisor**: Supervisory construction personnel. Responsible for ensuring that any unanticipated discoveries are promptly reported to the MPC Environmental Specialist and further disturbance halts as required in this plan. Supervisors are also responsible for confirming that workers under their direction are familiar with and adhere to the requirements of this plan.

3 Protocol for the Unanticipated Discovery of Cultural Resources

Cultural resources typically consist of archaeological and historic architectural resources. Archaeological resources are defined as any site location that contains material remains of past human life or activities, or other places and/or items that possess cultural importance to individuals or a group. They are typically identified on the surface or below ground. Historic architectural resources include "buildings, bridges, tunnels, statues, and other structures that create tangible links to the American past, whether in relation to historical events and people, traditional ways of life, architectural design, or methods of construction"[1]. Historic architectural resources are above ground resources.

3.1 Recognizing Cultural Resources

A cultural resource discovery could be precontact (i.e., from a time period that predates Native American contact with Europeans) or historic in nature. Examples include, but are not limited to:

- An accumulation of shell, burned rocks, or other food-related materials.
- Bones, intact or in small pieces and burned or unburned.
- An area of charcoal or very darkly stained soil, with or without artifacts.
- Stone tools or waste flakes (for example, an arrowhead or stone chips), or precontact ceramics.
- Modified natural features, such as rock drawings.
- Agricultural or industrial materials that appear older than 50 years. These could include equipment, fencing, canals, derelict buildings, tools, and many other items.
- Clusters of tin cans, bottles, or other debris that appear older than 50 years.
- Old munitions casings. **Always assume these are live and never touch or move**.
- Railroad tracks, decking, foundations, or other industrial materials.
- Foundation remnants, cisterns, and wells.
- Remnants of homesteading. These could include bricks, nails, household items, toys, food containers, and other items associated with homes or farming sites.

The above list does not cover every possible cultural resource. When in doubt, assume the material is a cultural resource. Example photographs of cultural resources that could be encountered during the Project are included in Attachment 1.

[1] https://www.nps.gov/orgs/1027/architecture.htm

3.2 Protocol

If an archaeological monitor, employee, contractor, or subcontractor believes that they have uncovered cultural resources or human remains at any point in the Project, take the following steps to **Stop-Notify-Protect**. If you suspect that the discovery includes **human remains**, follow the protocol outlined in **Section 4**. A flow chart with additional information regarding the procedures to be followed in the event that cultural resources are inadvertently discovered is included in Attachment 2.

STEP 1: Stop Work

All work must stop within the immediate vicinity, defined as within 100 feet of the discovery.

STEP 2: Notify the Appropriate Personnel

Either the Archaeological Monitor (if present) or the Supervisor will notify the MPC Environmental Specialist of the accidental discovery. The MPC Environmental Specialist then has 48 hours to notify the SHPO and THPOs by email or telephone.

During the discovery, the Supervisor in charge is responsible for informing persons in the area who are associated with the Project that they will be subject to prosecution for knowingly disturbing historic or archaeological sites or collecting artifacts.

STEP 3: Protect the Discovery

Leave the discovery and the surrounding area untouched and create a clear, identifiable, and wide boundary of 100 feet or larger with temporary fencing, flagging, stakes, or other clear markings. Provide protection of the discovery until cleared by the MPC Environmental Specialist.

Do not permit vehicles, equipment, or unauthorized personnel to traverse the discovery site. Do not allow work to resume within the boundary until clearance is received from the MPC Environmental Specialist.

STEP 4: Archaeological Investigation

The SHPO-permitted archaeological consultant or Archaeological Monitor will determine if the discovery is cultural and, if so, record and evaluate the discovery and make a recommendation of eligibility and effect. The archaeological investigation and evaluation will follow North Dakota SHPO standards.

STEP 5: Clearance

Following the appropriate archaeological investigation and eligibility determination for the cultural resource(s), the SHPO will issue a written letter of concurrence and construction will be allowed to resume in the area of the discovery. Work may not resume within the 100-foot buffer until SHPO concurrence and the the Supervisor in charge has received authorization to proceed from the MPC Environmental Specialist.

3.3 Points of Contact, Unanticipated Discovery of Cultural Resources

The following points of contact have been identified for the Project in the event that cultural resources are discovered.

Table 3-1 Points of Contact, Unanticipated Discovery of Cultural Resources

Position	Name	Phone Number
MPC Environmental Specialist	Samantha Roberts	(701) 795-4289
SHPO	Andrew Robinson	(701) 328-3575
SHPO-permitted Archaeological Consultant	John Morrison	(701) 400-3575
Archaeological Monitor	Pending	
Supervisor	Pending	
Chairman, Apache Tribe of Oklahoma	Durell Cooper or Bobby Komardley	(405) 247-9493
THPO, Fort Belknap Indian Community of the Fort Belknap Reservation of Montana	Michael Blackwolf	(406) 353-2295
THPO, Three Affiliated Tribes of the Forth Berthold Reservation, North Dakota	Allan Demaray	(701) 421-6640

4 Protocol for the Unanticipated Discovery of Human Remains

Any human remains or suspected human remains, regardless of antiquity or ethnic origin, will always be treated with dignity and respect. Human remains or suspected human remains may be associated with any of the following: funerary objects, sacred objects, or objects of cultural patrimony. Follow these steps to **Stop-Notify-Protect**. A flow chart with additional information regarding the procedures to be followed in the event that human remains are inadvertently discovered is included in Attachment 3.

STEP 1: Stop Work

All work must stop within the immediate vicinity, defined as within **300 feet** of the discovery. It is very important for law enforcement personnel and the SHPO or North Dakota Department of Health to examine the location as it was found.

STEP 2: Notify the Appropriate Personnel

Notify the Supervisor and Archaeological Monitor (if present) of the accidental discovery and suspected human remains. In turn, the Supervisor will **immediately** notify the MPC Environmental Specialist by telephone with follow-up written confirmation. The MPC Environmental Specialist will contact and coordinate with the appropriate Law Enforcement Agency and the SHPO. The SHPO will notify the North Dakota Department of Health.

During the time of the discovery, the Supervisor in charge is responsible for informing persons in the area who are associated with the Project that they will be subject to prosecution for knowingly disturbing human remains or collecting artifacts.

STEP 3: Protect the Discovery

Leave the discovery and the surrounding area untouched and create a clear, identifiable, and wide boundary of **300 feet** or larger with temporary fencing, flagging, stakes, or other clear markings. Provide protection of the discovery until cleared by the MPC Environmental Specialist.

Cover the remains with a tarp or other materials (not soil or rocks) for temporary protection and shield them from being photographed by others or disturbed.

Do not permit vehicles, equipment, or unauthorized personnel to traverse the discovery site or 300-foot buffer area. Do not allow work to resume within this boundary until clearance is received from the MPC Environmental Specialist.

DO NOT speak with the media, allow photography or disturbance of the remains, or release any information about the discovery on social media.

STEP 4: Investigation of Human Remains

If the Law Enforcement Agency determines the human remains are not part of a crime scene, the SHPO will determine if the human remains are Native American in origin. If it is determined that the human remains are not Native American and the remains cannot be avoided by Project activities, the SHPO-permitted Archaeological Consultant will proceed in a similar manner to the Unanticipated Discovery procedures listed in Step 4, Section 3.2 above. If it is determined that the human remains are Native American, or if the discovery includes funerary objects, sacred objects, or objects of cultural patrimony, the SHPO will notify the North Dakota Intertribal Reinterment Committee and consultation with tribes will need to occur regarding avoidance or disinterment.

STEP 5: Clearance

Construction activities will not be allowed to resume within 300 feet of the discovery until the MPC Environmental Specialist provides authorization.

4.1 Points of Contact, Unanticipated Discovery of Human Remains

The following points of contact have been identified for the Project in the event that human remains are discovered.

Table 4-1 Points of Contact, Unanticipated Discovery of Human Remains

Position	Name	Phone Number
MPC Environmental Specialist	Samantha Roberts	(701) 795-4289
SHPO	Andrew Robinson	(701) 328-3575
SHPO-permitted Archaeological Consultant	John Morrison	(701) 400-3575
Archaeological Monitor	Pending	
Supervisor	Pending	
Local Law Enforcement	Center Police Department	(701) 794-3591
County Law Enforcement	Oliver County Sheriff	(701) 794-3450 (office)
County Coroner/Medical Examiner	Thomas Kaspari	(701) 873-4445
Chairman, Apache Tribe of Oklahoma	Durell Cooper or Bobby Komardley	(405) 247-9493
THPO, Fort Belknap Indian Community of the Fort Belknap Reservation of Montana	Michael Blackwolf	(406) 353-2295
THPO, Three Affiliated Tribes of the Forth Berthold Reservation, North Dakota	Allan Demaray	(701) 421-6640

Attachment 1

Example Cultural Resources

Photographs

Stone Tool

Stone Tool and Waste Flakes

Precontact Ceramics

Precontact Ceramics

Darkly Stained Soil; Accumulation of Burned Rocks

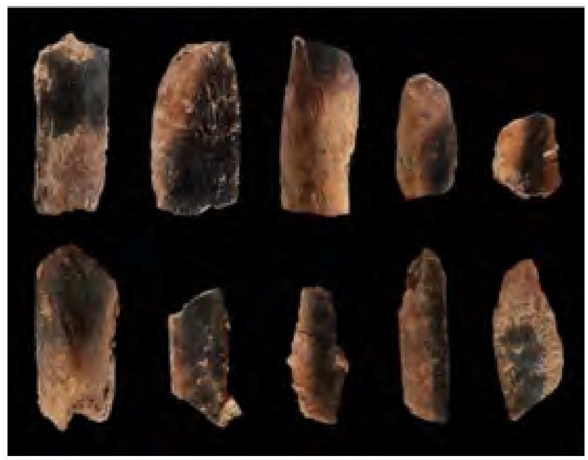

Stone Circle[2]

[2] Ed Horner, Fratermanor (https://commons.wikimedia.org/wiki/File:Teepee_rings.jpg), https://creativecommons.org/licenses/by-sa/4.0/legalcode


Derelict Building


Agricultural/Industrial Tool


Cluster of Historic Cans and Bottles


Burned and Unburned Bone[3]


Foundation Remnant

[3]Ruth Blasco (https://commons.wikimedia.org/wiki/File:Qesem_Cave_burned_animal_bones.jpg), https://creativecommons.org/licenses/by/4.0/legalcode

Foundation Remnant

Remnant Well

Homesteading Remnants (Historic Artifacts)

Homesteading Remnants (Historic Artifacts)

Abandoned Historic Vehicle[4]

[4] Jim Choate (https://www.flickr.com/photos/jimchoate/51532927587), https://creativecommons.org/licenses/by-nc/2.0/legalcode

Attachment 2

Flow Chart for Unanticipated Discoveries

Cultural Resources


Accidental Discovery Occurs
Halt all work within 100 ft radius (Stop Work Order) Notify the MPC Environmental Specialist Flag off the avoidance area
Within 24 hours, the SHPO-permitted archaeological consultant will examine the discovery and determine if a cultural resource has been identified
The SHPO-permitted archaeological consultant determines the discovery is NOT a cultural resource
The SHPO-permitted archaeologist notifies the MPC Environmental Specialist
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
The SHPO-permitted archaeological consultant determines the discovery IS a cultural resource
The SHPO-permitted archaeologist notifies the MPC Environmental Specialist
The MPC Environmental Specialist notifies the SHPO within 24 hours of the determination
The SHPO-permitted archaeological consultant finds the resource to be NOT SIGNIFICANT
The SHPO-permitted archaeological consultant prepares a written summary of findings
MPC Environmental Specialist submits findings to SHPO for permission for construction to recommence
SHPO permission received
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
SHPO permission NOT received
Additional consultation occurs between the MPC Environmental Specialist, the SHPO-permitted archaeological consultant, and the SHPO
The SHPO-permitted archaeo-logical consultant finds the resource MAY BE SIGNIFICANT
Scope-of-work for evaluating the significance of the resource and potential project effects on the resource (Evaluation Plan) prepared and submitted to the SHPO
Evaluation Plan approved by the SHPO
Additional archaeological testing com-pleted pursuant to the Evaluation Plan
Resource determined to be SIGNIFICANT
Finding Report and Treatment Plan prepared and submitted to the SHPO
SHPO agrees with the Findings and Treatment Plan
Treatment measures completed
Treatment Report prepared and submitted to SHPO
SHPO approves Treatment Report
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
SHPO does not approve Treatment Report
Additional consultation occurs between the MPC Environmental Specialist, the SHPO-permitted archaeological consultant, and the SHPO
SHPO does not agree with the Findings and/or Treatment Plan
Additional consultation occurs between the MPC Environmental Specialist, the SHPO-permitted archaeological consultant, and the SHPO

Attachment 3

Flow Chart for Unanticipated Discoveries

Human Remains


Accidental Discovery Occurs
Discovery determined to be human remains
Halt all work within 300 ft radius (Stop Work Order)
Notify the MPC Environmental Specialist
Flag off the avoidance area
MPC Environmental Specialist will notify the appropriate law enforcement agency and SHPO
The human remains are forensic in nature
Law enforcement coordinates with the Supervisor and the MPC Environmental Specialist regarding removal of the remains
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
The human remains are archaeological in nature
The human remains can be avoided by Project activities
SHPO notifies the North Dakota Intertribal Reinterment Committee (if remains are precontact)
The SHPO-permitted archaeological consultant prepares a Finding Report and Avoidance Plan for submittal to SHPO
SHPO approves the Report and Avoidance Plan
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
The human remains cannot be avoided by Project activities
Historic Burial
Consultation occurs between the SHPO, the SHPO-permitted archaeological consultant and MPC to determine disinterment methodology and reinterment location
The SHPO-permitted archaeological consultant prepares a Disinterment Plan for submittal to SHPO
Disinterment Plan approved
Disinterment occurs
The SHPO-permitted archaeological consultant prepares a Finding Report and for submittal to SHPO
SHPO approves the Report
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
Precontact Burial
SHPO notifies the North Dakota Intertribal Reinterment Committee
Consultation occurs between the SHPO, the North Dakota Intertribal Reinterment Committee, Native American tribes, the SHPO-permitted archaeological consultant and MPC to determine disinterment methodology and reinterment location
The SHPO-permitted archaeological consultant prepares a Disinterment Plan for submittal to SHPO and tribes
Disinterment Plan approved
Disinterment occurs
The SHPO-permitted archaeological consultant prepares a Finding Report and for submittal to SHPO and tribes
SHPO and tribes approve the Report
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume

APPENDIX J – AIR PERMIT TO CONSTRUCT, AIR QUALITY EMISSIONS ANALYSIS, AND AIR QUALITY IMPACT ANALYSIS

NORTH Dakota | Environmental Quality

Be Legendary.™

December 29, 2023

Mr. Robert McLennan
President and CEO
DCC East Project LLC
5301 32nd Avenue South
Grand Forks, ND 58201

Re: Air Pollution Control
Permit to Construct No. ACP-18194 v1.0

Dear Mr. McLennan,

Pursuant to the Air Pollution Control Rules of the State of North Dakota, the Department of Environmental Quality (Department) has completed its final review of your permit application dated June 2, 2023, to obtain a Permit to Construct for initial construction and operation of the Dakota Carbon Center CO2 Separation and Purification Plant to be located in Oliver County, North Dakota.

Based on the results of the documents reviewed, the Department hereby issues the enclosed North Dakota Air Pollution Control Permit to Construct No. ACP-18194 v1.0. A public comment period was held regarding this project from September 21, 2023, through October 21, 2023. Comments were received from three parties which consisted of two individual commentors and Region 8 of the Environmental Protection Agency. This information is included in Appendix A – Public Record. The Department provided written response to each applicable comment, also included in Appendix A. The Department made logical-outgrowth changes from the draft Permit to Construct and Air Quality Effects Analysis that do not depart from the terms or substance of the proposed action. Therefore, the Department hereby issues the final permit to construct for the project.

Please notify the Department within 15 days after completing the project to allow for an inspection by the Department.

Note that the above-referenced permit addresses only air quality requirements applicable to your facility. Other divisions (Water Quality, Waste Management and Municipal Facilities) within the Department of Environmental Quality may have additional requirements. Contact information for the various divisions is listed at the bottom of this letter.

If you have any questions regarding air quality, please contact me at (701)328-5229 or destroh@nd.gov.

Sincerely,

David Stroh

David Stroh
Manager, Permit Program
Division of Air Quality

DS:
Enc:
xc: Adam Eisele, EPA Region 8 (email - eisele.adam@epa.gov)

NORTH Dakota | Environmental Quality
Be Legendary.™

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to Chapter 23.1-06 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33.1-15 of the North Dakota Administrative Code), and in reliance on statements and representations heretofore made by the owner designated below, a Permit to Construct is hereby issued authorizing such owner to construct and initially operate the source unit(s) at the location designated below. This Permit to Construct is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Environmental Quality (Department) and to any conditions specified below:

I. **General Information**:

A. **Permit to Construct Number**: ACP-18194 v1.0

B. **Source**:

1. Name: Dakota Carbon Center CO_2 Separation and Purification Plant

2. Location: 3401 24th Street SW
NE ¼ of Section 5, T.141N, R.83W
Lat/Long: 47.0648/-101.2178
Oliver County, ND

3. Source Type: Carbon dioxide (CO_2) separation and purification plant

4. Facility Emission Units:

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Carbon dioxide (CO_2) absorber column	D01	D01	N/A [A]
Cooling tower	D02	D02	Drift eliminators
Emergency diesel fire pump engine rated at 460 brake horsepower	D03	D03	None
Haul roads [B]	D04	D04	None
Storage tanks [B]	D05	D05	None
Fugitive components	FUG	FUG	None

[A] Process design and controls (i.e., construction material selection and intermediate cooling). No add-on controls.
[B] Insignificant unit

5. Storage Tanks (Insignificant Units):

Emission Unit Description	**Emission Unit (EU)**
Diesel fire pump storage tank	D05A
Solvent tank	D05B
Solvent sump tank	D05C
Reclaimed waste tank	D05D
Wash water tank	D05E
Dilute wash water tank	D05F
Fresh solvent tank	D05G
Triethylene glycol tank	D05H

C. **Owner/Operator (Permit Applicant)**:

1. Name: DCC East Project LLC

2. Address: 3401 24th Street SW
Center, ND 58530

3. Application Date: June 2, 2023
August 25, 2023 (Revised modeling analysis)

II. **Conditions**:
This Permit to Construct allows the construction and initial operation of the above-mentioned new or modified equipment at the source. The source may be operated under this Permit to Construct until a Permit to Operate is issued unless this permit is suspended or revoked. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Environmental Quality and to the conditions specified below.

A. **Emission Limits**: Emission limits from the operation of the new source unit(s) identified in Item I.B of this Permit to Construct (hereafter referred to as "permit") are as follows. Source units not listed are subject to the applicable emission limits specified in the North Dakota Air Pollution Control Rules.

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Pollutant / Parameter**	**Emission Limit**
Cooling tower	D02	D02	$PM/PM_{10}/PM_{2.5}$	Condition II.E

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Pollutant / Parameter**	**Emission Limit**
Emergency diesel fire pump engine	D03	D03	Various SO_2	NSPS IIII, Table 4 Condition II.B

B. **Fuel Restrictions**: The emergency fire pump engine (EU D03) is restricted to combusting only distillate oil containing no more than 0.0015 percent sulfur by weight.

C. **New Source Performance Standards (NSPS)**: The permittee shall comply with all applicable requirements of the following NSPS subparts, in addition to Subpart A, as referenced in Chapter 33.1-15-12 of the North Dakota Air Pollution Control Rules and 40 CFR 60.

1. 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (EU D03).

D. **National Emissions Standards for Hazardous Air Pollutants (NESHAP)**: The permittee shall comply with all applicable requirements of the following NESHAP subparts, in addition to Subpart A, as referenced in Chapter 33.1-15-22 of the North Dakota Air Pollution Control Rules and 40 CFR 63.

1. 40 CFR 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (EU D03).

E. **Cooling tower (EU D02)**: The cooling tower shall be equipped with and operated with mist eliminators that are guaranteed to limit drift to 0.0005% or less of the circulating flow.

F. **Emissions Testing**: All initial testing will require a minimum of 3 runs, one hour each, unless otherwise specified in a federal subpart.

Emission Unit Description	Emission Point (EP)	Contaminant	Method
CO_2 absorber column	D01	Acetaldehyde [A]	Method 320 [C]
		Formaldehyde [A, B]	Method 320 [C]

[A] Acetaldehyde is projected to account for approximately 93% of all HAPs and is expected to be a surrogate for HAPs. Formaldehyde is projected to account for approximately 5%, meaning aldehyde HAPs are projected to account for 98% of all HAPs.

[B] If testing formaldehyde indicates results below Method detection limits, they will be considered insignificant by the Department.

[C] An equivalent reference method approved by the Department may be used.

A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the permittee shall follow the procedures and formats in the Department's Emission Testing Guideline[1].

1. Initial Testing: Within 180 days after initial startup, the permittee shall conduct emissions tests at the emission units listed above using an independent testing firm. Emissions testing shall be conducted for the pollutant(s) listed above in accordance with EPA Reference Methods listed in 40 CFR 60, Appendix A and/or 40 CFR 63, Appendix A. Test methods other than those listed above may be used upon approval by the Department.

2. Notification: The permittee shall notify the Department using the form in the Emission Testing Guideline, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department at least five days prior to the scheduled test date and coordinate a new test date with the Department.

3. Sampling Ports/Access: Sampling ports shall be provided downstream of all emission control devices and in a flue, conduit, duct, stack or chimney arranged to conduct emissions to the ambient air.

   The ports shall be located to allow for reliable sampling and shall be adequate for test methods applicable to the facility. Safe sampling platforms and safe access to

[1] See February 7, 2020, North Dakota Department of Environmental Quality Division of Air Quality Emissions Testing Guidelines. Available at: https://www.deq.nd.gov/publications/AQ/policy/PC/Emission_Testing_Guide.pdf

the platforms shall be provided. Plans and specifications showing the size and location of the ports, platform and utilities shall be submitted to the Department for review and approval.

4. Other Testing:

a) The Department may require the permittee to have tests conducted to determine the emission of air contaminants from any source, whenever the Department has reason to believe that an emission of a contaminant not addressed by the permit applicant is occurring, or the emission of a contaminant in excess of that allowed by this permit is occurring. The Department may specify testing methods to be used in accordance with good professional practice. The Department may observe the testing. All tests shall be conducted by reputable, qualified personnel. A signed copy of the test results shall be furnished to the Department within 60 days of the test date.

All tests shall be made available, and the results calculated in accordance with test procedures approved by the Department. All tests shall be made under the direction of persons qualified by training or experience in the field of air pollution control as approved by the Department.

b) The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

G. **Best Management Practices**: At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

1. Intermediate cooling in the CO_2 absorber column (EU D01) by cooling over the packing shall be always operated when the unit is in operation.

2. Periodic monitoring and recordkeeping demonstrating compliance with the CO_2 absorber column operations in accordance with the original equipment manufacturers specifications and good engineering practices.

3. Recordkeeping that demonstrates compliance with the MACT determination for materials selection in the CO_2 absorber column.

H. **Stack Heights**: Emissions from D01 shall be vented through stacks that meet the following height requirements. Stack heights may be no less than those listed in the table below without prior approval from the Department.

Emission Unit (EU)	Emission Point (EP)	Stack Height (Feet)
Carbon dioxide (CO_2) absorber column	D01	335

I. **Construction**: Construction of the above described facility shall be in accordance with information provided in the permit application as well as any plans, specifications and supporting data submitted to the Department. The Department shall be notified ten days in advance of any significant deviations from the specifications furnished. The issuance of this Permit to Construct may be suspended or revoked if the Department determines that a significant deviation from the plans and specifications furnished has been or is to be made.

Any violation of a condition issued as part of this permit to construct as well as any construction which proceeds in variance with any information submitted in the application, is regarded as a violation of construction authority and is subject to enforcement action.

J. **Startup Notice**: A notification of the actual date of initial startup shall be submitted to the Department within 15 days after the date of initial startup.

K. **Like-Kind Engine Replacement**: This permit allows the permittee to replace an existing engine with a like-kind unit. Replacement is subject to the following conditions:

1. The Department must be notified within 10 days after change-out of the unit.

2. The replacement unit shall operate in the same manner, provide no increase in throughput and have equal or less emissions than the unit it is replacing.

3. The date of manufacture of the replacement unit must be included in the notification. The facility must comply with any applicable federal standards (e.g. NSPS, MACT) triggered by the replacement.

4. The replacement unit is subject to the same state emission limits as the existing unit in addition to any NSPS or MACT emission limit that is applicable. Testing shall be conducted to confirm compliance with the emission limits within 180 days after start-up of the unit.

L. **Organic Compounds Emissions**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-07 – Control of Organic Compounds Emissions.

M. **Permit Invalidation**: This permit shall become invalid if construction is not commenced within eighteen months after issuance of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time, unless an extension is granted by the Department.

N. **Title V Permit to Operate**: Within one year after startup of the units covered by this Permit to Construct, the permittee shall submit a permit application for a Title V Permit to Operate for the facility.

O. **Fugitive Emissions**: The release of fugitive emissions shall comply with the applicable requirements in NDAC 33.1-15-17.

P. **Annual Emission Inventory/Annual Production Reports**: The permittee shall submit an annual emission inventory report and/or an annual production report upon Department request, on forms supplied or approved by the Department.

Q. **Source Operations**: Operations at the installation shall be in accordance with statements, representations, procedures and supporting data contained in the initial application, and any supplemental information or application(s) submitted thereafter. Any operations not listed in this permit are subject to all applicable North Dakota Air Pollution Control Rules.

R. **Alterations, Modifications or Changes**: Any alteration, repairing, expansion, or change in the method of operation of the source which results in the emission of an additional type or greater amount of air contaminants or which results in an increase in the ambient concentration of any air contaminant, must be reviewed and approved by the Department prior to the start of such alteration, repairing, expansion or change in the method of operation.

S. **Air Pollution from Internal Combustion Engines**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-08-01 – Internal Combustion Engine Emissions Restricted.

T. **Recordkeeping**: The permittee shall maintain any compliance monitoring records required by this permit or applicable requirements. The permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information may include all calibration and maintenance records and all original strip-chart recordings/computer printouts for continuous monitoring instrumentation, and copies of all reports required by the permit.

U. **Nuisance or Danger**: This permit shall in no way authorize the maintenance of a nuisance or a danger to public health or safety.

V. **Malfunction Notification**: The permittee shall notify the Department of any malfunction which can be expected to last longer than twenty-four hours and can cause the emission of air contaminants in violation of applicable rules and regulations.

W. **Operation of Air Pollution Control Equipment**: The permittee shall maintain and operate all air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

X. **Transfer of Permit to Construct**: The holder of a permit to construct may not transfer such permit without prior approval from the Department.

Y. **Right of Entry**: Any duly authorized officer, employee or agent of the North Dakota Department of Environmental Quality may enter and inspect any property, premise or place at which the source listed in Item I.B of this permit is located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.

Z. **Other Regulations**: The permittee of the source unit(s) described in Item I.B of this permit shall comply with all State and Federal environmental laws and rules. In addition, the permittee shall comply with all local burning, fire, zoning, and other applicable ordinances, codes, rules and regulations.

AA. **Permit Issuance**: This permit is issued in reliance upon the accuracy and completeness of the information set forth in the application. Notwithstanding the tentative nature of this information, the conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has, or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23.1-06.

BB. **Odor Restrictions**: The permittee shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33.1-15-16.

CC. **Sampling and Testing**: The Department may require the permittee to conduct tests to determine the emission rate of air contaminants from the source. The Department may observe the testing and may specify testing methods to be used. A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the permittee shall follow the procedures and formats in the Department's Emission Testing Guideline.

FOR THE
NORTH DAKOTA DEPARTMENT
OF ENVIRONMENTAL QUALITY

Date: 12/29/2023 By: James L. Semerad

James L. Semerad
Director
Division of Air Quality

NORTH Dakota | Environmental Quality
Be Legendary.™

AIR QUALITY EFFECTS ANALYSIS
FOR
PERMIT TO CONSTRUCT
ACP-18194 v1.0

Applicant:

DCC East Project LLC
3401 24th Street SW
Center, North Dakota 58530

Facility Location:

Dakota Carbon Center CO_2 Separation and Purification Plant
3401 24th Street SW
Center, North Dakota 58530
Lat/Long: 47.0648/-101.2178
NE ¼ of Section 5, T.141N, R.83W

Introduction and Background:

DCC East Project LLC (DCC) submitted a permit to construct application to the North Dakota Department of Environmental Quality – Division of Air Quality (Department) on June 2, 2023. The air dispersion modeling analysis for the project was revised and submitted to the Department on August 25, 2023. The application was for the construction of the Dakota Carbon Center Carbon Dioxide (CO_2) Separation and Purification Plant (Project). The Project will be located adjacent to the existing Milton R. Young (MRY) Station and is designed to capture, purify, and sequester up to 13,000 tons per day (~4.75 million tons per year) of CO_2 from MRY Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2).

DCC's Project will be considered a separate stationary source from the MRY Station for the purposes of the applicable air pollution control rules (40 CFR Part 63 and 40 CFR Part 70). Part 63 requires two criteria to be met for two (or more) sources to be considered a single major source, the sources must be "located within a contiguous area and under common control". Part 70 contains the same first two criteria and adds a third criteria, that sources must belong to the same major industrial grouping. DCC will be responsible for operational control of the Project, including control over air emitting activities that affect permit compliance (i.e., not under common control), and the owner of MRY Station will not hold a majority ownership in DCC. DCC's Project has standard industrial classification (SIC) code 2813 compared to MRY Station SIC code of 4911 (i.e., do not belong to the same industrial grouping). DCC will be adjacent to MRY Station, so the facilities will be located within a continuous area. Of the Part 63 and Part 70 criteria the Project only meets one of the necessary criteria; therefore, the Project is considered a separate source.

Note: MRY Station operates under Title V Permit to Operate (PTO) T5-F76009 (AOP-28368 v5.0) which expires on May 12, 2025. T5-F76009 contains all the equipment onsite at MRY Station and has incorporated all previously issued air pollution control construction permits. T5-F76009 monitoring requirements and conditions will be updated upon issuance of this permit to ensure MRY Station will be able to continually demonstrate compliance with the limits in T5-F76009 at existing MRY Station emission points (EPs) and proposed EP D01.

Table 1 lists all the emissions units associated with the Project and Table 2 contains a list of all insignificant storage tanks.

Table 1 – Project Emission Units and Emission Points

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Carbon dioxide (CO_2) absorber column	D01	D01	N/A [A]
Cooling tower	D02	D02	Drift eliminators
Emergency diesel fire pump engine rated at 460 brake horsepower	D03	D03	None
Haul roads [B]	D04	D04	None
Storage tanks [B]	D05	D05	None
Fugitive components	FUG	FUG	None

[A] Process design and controls (i.e., construction material selection and intermediate cooling). No add-on controls.

[B] Insignificant unit

Table 2 – Project Insignificant Units (Storage Tanks)

Emission Unit Description	**Emission Unit (EU)**
Diesel fire pump storage tank	D05A
Solvent tank	D05B
Solvent sump tank	D05C
Reclaimed waste tank	D05D
Wash water tank	D05E
Dilute wash water tank	D05F
Fresh solvent tank	D05G
Triethylene glycol tank	D05H

Facility Wide Emissions Profile
Potential to Emit (PTE) from Standalone Project

Table 3 - PTE (tons per year) [A]

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	CO	NO_X	SO_2	VOCs	PM	PM_{10}	$PM_{2.5}$	Total HAPs	Acetaldehyde (Largest HAP)
CO_2 absorber	D01	D01	--	--	--	35.2	--	--	--	35.2	32.9
Cooling tower	D02	D02	--	--	--	--	22.2	4.0	0.0	--	--
Fire water pump engine	D03	D03	0.1	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Haul roads	D04	D04	--	--	--	--	0.2	0.0	0.0	--	--
Storage tanks	D05	D05	--	--	--	0.3	--	--	--	0.0	--
Fugitive components	FUG	FUG	--	--	--	4.3	--	--	--	--	--
		Total:	**0.1**	**0.2**	**0.0**	**39.9**	**22.4**	**4.1**	**0.0**	**35.2**	**32.9**

[A] Abbreviations:
PM: total filterable and condensable particulate matter
$PM_{2.5}$: filterable and condensable particulate matter with an aerodynamic diameter less than or equal to 2.5 microns (≤2.5 µm)
PM_{10}: filterable and condensable particulate matter with an aerodynamic diameter less than or equal to 10 microns (≤10 µm) including $PM_{2.5}$
SO_2: sulfur dioxide
NO_X: oxides of nitrogen
CO: carbon monoxide
VOCs: volatile organic compounds
HAPs: hazardous air pollutants as defined in Section 112(b) of the Clean Air Act

Rules Analysis
Potentially Applicable Rules and Expected Compliance Status

A. NDAC 33.1-15-01 - General Provisions:

Multiple topics are included in the General Provisions chapter, these include: entry onto premises - authority, variances, circumvention, severability, land use plans and zoning regulations (only to provide air quality information), measurement of air contaminants, shutdown and malfunction of an installation - requirements for notification, time schedule for compliance, prohibition of air pollution, confidentiality of records, enforcement, and compliance certifications.

Applicability and Expected Compliance

Based on the review of the information provided, the Project will comply with all applicable sections of this rule.

B. NDAC 33.1-15-02 - Ambient Air Quality Standards:

The facility must comply with the North Dakota and Federal Ambient Air Quality Standards (AAQS). In addition to these standards, compliance with the "Criteria Pollutant Modeling Requirements for a Permit to Construct" guidelines[1] and the "Policy for the Control of Hazardous Air Pollutant Emissions in North Dakota (Air Toxics Policy)"[2] is required.

Applicability and Expected Compliance

The Project does not trigger the prevention of significant deterioration (PSD) program emissions thresholds which require modeling nor do the Project emissions meet thresholds required for non-PSD required modeling under the "Criteria Pollutant Modeling Requirements for a Permit to Construct". Notwithstanding that the emissions thresholds are below North Dakota's modeling guidelines, modeling for this project was required and is appropriate and necessary since the current emissions from MRY Station will be diverted and emitted through a stack with significantly different stack characteristics. Therefore, preconstruction modeling for the Project was required to demonstrate the Project will not significantly impact the existing airshed and will not cause an AAQS violation.

The results of the preconstruction modeling demonstrate the altered dispersion characteristics associated with the Project are not expected to cause or contribute to an exceedance of the AAQS. The preconstruction permit modeling was also used to demonstrate compliance with the Department's Air Toxics Policy. Modeling demonstrated that the Project is expected to comply with both the AAQS and the Department's Air Toxic Policy. Details regarding the preconstruction permit modeling analysis and results are

[1] See October 6, 2014, Criteria Pollutant Modeling Requirements for a Permit to Construct. Available at: https://www.deq.nd.gov/publications/AQ/policy/Modeling/Criteria_Modeling_Memo.pdf
[2] See August 25, 2010, Policy for the Control of Hazardous Air Pollutant (HAP) Emissions in North Dakota. Available at: https://www.deq.nd.gov/publications/AQ/policy/Modeling/Air_Toxics_Policy.pdf

discussed in the Air Quality Impacts Analysis (AQIA) associated with this permitting action. See “ACP-18194 v1.0_AQIA” for details.

C. NDAC 33.1-15-03 - Restriction of Emission of Visible Air Contaminants:

This chapter requires all non-flare sources from new facilities to comply with an opacity limit of 20% except for one six-minute period per hour when 40% opacity is permissible. This chapter also requires facility flares to comply with an opacity limit of 20% except for one six-minute period per hour when 60% opacity is permissible. Lastly, this chapter restricts opacity of fugitive emissions transported off property to 40% except for one six-minute period per hour when 60% opacity is permissible. This chapter also contains exceptions under certain circumstances and provides the method of measurement to determine compliance with the referenced limits.

Applicability and Expected Compliance

Based on the emissions units associated with the Project, the Department expects the Project will comply with the non-flare source and fugitive emissions opacity requirements.

The CO_2 absorber column (EU D01), the cooling tower (EU D02) and the emergency diesel fire pump engine (EU D03) are subject to the non-flare source 20% opacity limit and are expected to comply. EU D01 is not expected to have any significant opacity associated with routine operations. Opacity from EU D01 would indicate an issue with the Project operations that would require investigation and resolution. EU D02 is designed with drift elimination technology. Any opacity will be associated with routine operations and expected to be well below 20%. EU D03 is also not expected to have any significant opacity associated with its emergency operations. EU D03 is also subject to NDAC 33.1-15-08 and NDAC 33.1-15-12 (Subpart IIII).

The haul roads (EU D04) are subject to the fugitive emissions transported offsite limit of 40%. The Project will maintain EU D04 using reasonable practices to comply with this limit.

D. NDAC 33.1-15-04 - Open Burning:

No person may dispose of refuse and other combustible material by open burning, or cause, allow, or permit open burning of refuse and other combustible material, except as provided for in Section 33.1-15-04-02 or 33.1-15-10-02, and no person may conduct, cause, or permit the conduct of a salvage operation by open burning.

Applicability and Expected Compliance

The Project is subject to this chapter and will comply with all open burning regulations.

E. NDAC 33.1-15-05 - Emissions of Particulates Matter Restricted:

This chapter establishes particulate matter emission limits for industrial process equipment and fuel burning equipment used for indirect heating.

Applicability and Expected Compliance

The Project will not emit any particulate matter which results from industrial process equipment, nor will the facility operate any fuel burning equipment used for indirect heating.

F. NDAC 33.1-15-06 - Emissions of Sulfur Compounds Restricted:

This chapter applies to any installation in which fuel is burned and the SO_2 emissions are substantially due to the sulfur content of the fuel; and in which the fuel is burned primarily to produce heat. This chapter is not applicable to installations which are subject to an SO_2 emission limit under Chapter 33.1-15-12, Standards for Performance for New Stationary Sources, or installations which burn pipeline quality natural gas.

Applicability and Expected Compliance

The Project will not emit any SO_2 which results from industrial process equipment, nor will the Project operate any fuel burning equipment used for indirect heating. The emergency fire water pump (ED D03) will comply with this chapter by burning ultra-low sulfur diesel.

G. NDAC 33.1-15-07 - Control of Organic Compounds Emissions:

This chapter establishes requirements for organic compound facilities and the disposal of organic compounds.

Applicability and Expected Compliance

The Project is not considered an organic compound facility, but the Project will emit organic compounds via the CO_2 absorber column (EU D01) exhaust. The organic compounds concentration in this stream is expected to be less than 1 part per million by volume dry (ppmvd) and D01 contains process controls (e.g., material selection and intermediate cooling) which limit the generation of organic compounds in the CO_2 absorber column. These controls are considered maximum achievable control technology (MACT). Therefore, the Project is expected to comply with the requirements of this chapter.

The Department encourages DCC to conduct periodic leak detection monitoring on the process equipment to minimize losses of valuable materials.

H. NDAC 33.1-15-08 - Control of Air Pollution from Vehicles and Other Internal Combustion Engines:

This chapter restricts the operation of internal combustion engines which emit from any source unreasonable and excessive smoke, obnoxious or noxious gas, fumes or vapor. This chapter also prohibits the removal or disabling of motor vehicle pollution control devices.

Applicability and Expected Compliance

The emergency diesel fire pump (EU D03) is also subject to opacity requirements under NDAC 33.1-15-03-02 and subject to the requirements of NSPS Subpart IIII. As a result of expected compliance with these provisions, the engine is not expected to emit any unreasonable and excessive smoke, obnoxious or noxious gases, fumes, or vapor. Any vehicles used onsite are also expected to comply with this chapter's provisions.

I. NDAC 33.1-15-09 - [repealed]

J. NDAC 33.1-15-10 - Control of Pesticides:

This chapter provides restrictions on pesticide use and restrictions on the disposal of surplus pesticides and empty pesticide containers.

Applicability and Expected Compliance

The Project is subject to this chapter and is expected to comply with all applicable requirements should pesticides be used.

K. NDAC 33.1-15-11 - Prevention of Air Pollution Emergency Episodes:

When an air pollution emergency episode is declared by the Department, the Project shall comply with the requirements in Chapter 33.1-15-11 of the North Dakota Air Pollution Control (NDAPC) rules.

L. NDAC 33.1-15-12 - Standards of Performance for New Stationary Sources [40 Code of Federal Regulations Part 60 (40 CFR Part 60)]:

This chapter adopts most of the Standards of Performance for New Stationary Sources (NSPS) under 40 CFR Part 60. The Project is subject to the following subparts under 40 CFR Part 60 which have been adopted by North Dakota:

Subpart A – General Provisions

Subpart A contains general requirements for plan reviews, notification, recordkeeping, performance tests, reporting, monitoring and general control device requirements.

Applicability and Expected Compliance

The Project will comply with the general provisions of Subpart A through submission of timely notifications, performance testing, reporting, and following the general control device and work practice requirements under Subpart A. In addition, any changes to the Project after it is built will be evaluated with respect to this subpart as well as others.

Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII establishes emissions standards (NO_X, CO, PM, and Non-methane hydrocarbons) and compliance schedules for all new, modified and reconstructed stationary compressions ignition (CI) internal combustion engines (ICE). CI ICE are categorized in this subpart by usage, size and age.

Applicability and Expected Compliance

The Project emergency fire water pump (EU D03) is rated at 460 brake horsepower and is subject to the requirements of Subpart IIII. Subpart IIII requires EU D03 to be certified to the standards listed in Table 4 to Subpart IIII[3]. Based on the information provided in the permit application, EU D03 will comply with the applicable requirements of this subpart.

M. NDAC 33.1-15-13-Emission Standards for Hazardous Air Pollutants [40 Code of Federal Regulations Part 61 (40 CFR Part 61)]

This chapter adopts most the National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 61.

Applicability and Expected Compliance

The Project does not appear to have any applicable requirements under this chapter.

N. NDAC 33.1-15-14-Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate

This chapter requires the facility to obtain a Permit to Construct and a Permit to Operate.

Applicability and Expected Compliance

DCC has submitted an application for a permit to construct for the Project and has met all requirements necessary to obtain a permit to construct. The Project will be considered a minor PSD source, a major source of HAPs, and a future major stationary source under 40 CFR Part 70 (Title V).

The permit must undergo public comment per NDAC 33.1-15-14-06.5.a.

Once the Project completes construction and meets the permit to construct requirements, a facility inspection will be performed by the Department. After Project start-up, DCC will be required to submit a timely Title V permit to operate application.

[3] See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-IIII#Table-4-to-Subpart-IIII-of-Part-60 for Table 4 of NSPS Subpart IIII.

O. NDAC 33.1-15-15-Prevention of Significant Deterioration of Air Quality [40 CFR 52.21]

This chapter adopts the federal provisions of the prevention of significant deterioration of air quality (PSD) program. A facility is subject to PSD review if it is classified as a "major stationary source" under Chapter 33.1-15-15.

Applicability and Expected Compliance

The Project does not meet the definition of a "major stationary source" under 40 CFR 52.21(b)(1)(i)(a) since the regulated NSR pollutant[4] emissions do not meet the applicable requirements. The PTE for this facility, as shown in Table 3, is below the 100 tpy threshold and therefore not subject to PSD review.

P. NDAC 33.1-15-16 - Restriction of Odorous Air Contaminants

This chapter restricts the discharge of objectionable odorous air contaminants which measures seven odor concentration units or greater outside the property boundary.

Applicability and Expected Compliance

Based on Department expectations considering the source units, the Project should not emit any objectionable odorous air contaminants. Therefore, the Project is expected to comply with this chapter.

Q. NDAC 33.1-15-17 - Restriction of Fugitive Emissions

This Chapter restricts fugitive emissions from particulate matter or other visible air contaminates and gaseous emissions that would violate Chapter 2 (ambient air quality standards), Chapter 15 (PSD), Chapter 16 (odor), or Chapter 19 (visibility).

Applicability and Expected Compliance

DCC will be required to take reasonable precautions to prevent fugitive emissions in violation of the above referenced NDAC chapters.

R. NDAC 33.1-15-18 - Stack Heights

This chapter restricts the use of stack heights above good engineering practices (GEP). This chapter also restricts the use of dispersion techniques to affect the concentration of a pollutant in the ambient air.

Applicability and Expected Compliance

The main proposed stack (EU D01) for the Project does not exceed GEP and will not use dispersion techniques to affect the pollutant concentration in the ambient air.

---

[4] See 40 CFR 52.21(b)(50). Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-52/subpart-A/section-52.21#p-52.21(b)(50)

The required stack heights at the facility are listed in the following table:

Emission Unit	Emission Point (EP)	Stack Height (Feet)
D01	D01	335

S. NDAC 33.1-15-19 - Visibility Protection

This chapter applies to new major stationary sources as defined in Section 33.1-15-15-01.

Applicability and Expected Compliance

The Project is not an existing major stationary source and cannot experience a major modification. The Project is also not a new major stationary source; therefore, this Project is not subject to the requirements of this chapter. Given the minor source levels of the visibility impairing air pollutants, such as $PM_{2.5}$, it is expected that the Project will not adversely contribute to visibility impairment within the three units of the Theodore Roosevelt National Park (nearest federal Class I areas) or at the Lostwood National Wildlife Refuge.

T. NDAC 33.1-15-20 - Control of Emissions from Oil and Gas Well Production Facilities

The Project is not an oil or gas well facility and is therefore not subject to the requirements of this chapter.

U. NDAC 33.1-15-21 - Acid Rain Program

This chapter adopts the acid rain provisions of the Clean Air Act specified under 40 CFR Parts 72-78. The Project is not subject to the acid rain provision as it is not an electric utility.

V. NDAC 33.1-15-22 - Emissions Standards for Hazardous Air Pollutants for Source Categories [40 Code of Federal Regulations Part 60 (40 CFR Part 63)]

This chapter adopts the 40 CFR Part 63 regulations which regulates hazardous air pollutants (HAPs) from regulated source categories. Typically, these standards apply to major sources of air pollution that are a regulated source category. In addition to the major source requirements, some of the regulations have "area source" standards (for non-major sources). Some of the area source standards have not been adopted by the Department and compliance will be determined by the United States Environmental Protection Agency (USEPA) (i.e. 40 CFR 63, Subpart ZZZZ area source provisions have not been adopted by the Department).

Applicability and Expected Compliance

The Project's potential HAP emissions are greater than 10 tons/year of any single HAP and are greater than 25 tons/year of any combination of HAPs, so the Project is expected to be a major source of HAPs. As shown in the Table 3, total potential HAPs from the Project are approximately 35.2 tons/year. The greatest single potential HAP is acetaldehyde at approximately 32.9 tons/year.

DCC shall perform HAP emissions testing upon Project start-up to confirm the representations made in the permit application as outlined in Condition II.F of ACP-18194 v1.0.

Subpart A – General Provisions

Subpart A contains general requirements for prohibited activities and circumvention, preconstruction review and notification, standards and maintenance requirements, performance tests, monitoring, recordkeeping, reporting, and control device work practice requirements.

Applicability and Expected Compliance

The Project will comply with the general provisions of Subpart A through submission of timely notifications, performance testing, monitoring, recordkeeping, reporting, and following the control device work practice requirements under Subpart A.

Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)

Under the Clean Air Act Amendments of 1990, EPA is required to regulate large or "major" industrial facilities that emit one or more of the listed HAPs. Air toxics are those pollutants that are known or suspected of causing cancer or other serious health effects, such as developmental effects or birth defects. On July 16, 1992, EPA published a list of industrial source categories that emit one or more of these hazardous air pollutants. EPA is required to develop standards for listed industrial categories of "major" sources (those that have the potential to emit 10 tons/year or more of a listed pollutant or 25 tons/year or more of a combination of pollutants) that will require the application of stringent controls, known as maximum achievable control technology (MACT).

The section 112(g) provision is designed to ensure that emissions of toxic air pollutants do not increase if a facility is constructed or reconstructed before EPA issues a MACT or air toxics regulation for that particular category of sources or facilities.

In effect, the 112(g) provision is a transitional measure to ensure that facilities adequately protect the public from toxic air pollutants until EPA issues a MACT standard that applies to the facility in question.

Newly constructed facilities or reconstructed units or sources at existing facilities would be subject to 112(g) requirements if they have the potential to emit hazardous air pollutants (air toxics) in "major" amounts (10 tons or more of an individual pollutant or 25 tons or more of a combination of pollutants).

Sources or facilities subject to 112(g) would be subject to stringent air pollution control requirements, referred to as "new source MACT." Under the Clean Air Act, new source

MACT control is required to be no less stringent than the best controlled similar source or facility.

EPA anticipates that the new source MACT requirements will be equally or more stringent than the requirements in the air toxics or MACT standard that EPA will later issue for the industrial source category in question. However, should the new source MACT requirements prove to be less stringent than the air toxics regulation that EPA later issues, the source or facility would be provided additional time to comply with the air toxics or MACT standard.[5]

Applicability and Expected Compliance

The Project's potential HAP emissions are greater than 10 tons/year of any single HAP and are greater than 25 tons/year of any combination of HAPs. EPA has not established MACT standards for the Project's source category; therefore, a new source MACT determination was made for the Project.

DCC's permit to construct application included a detailed analysis of potentially available controls to reduce VOC/HAP emissions from the CO_2 absorber (EU D01).[6] The Department supports the analysis and agrees with the conclusions reached in the selection of MACT for the CO_2 absorber. The Department has determined MACT for the Project's CO_2 absorber to be process controls integrated into the design of the system, which consists of CO_2 absorber material selection and intermediate cooling. Material selection to limit iron scavenging and intermediate cooling to prevent excess heat are expected to reduce the amount of amine degradation in the CO_2 absorber column, thereby lessening the amount of VOC/HAP formation. It is estimated that these changes will result in approximately 40% less VOC/HAP emissions when compared to pre-design integrated process control levels based on vendor calculations. The selection of MACT for the Project is also consistent with the control approach implemented at the Petra Nova carbon capture facility in Texas.

The permit application projects that acetaldehyde emissions account for approximately 93% of the expected combined (or total) HAPs and that acetaldehyde will be emitted from the CO_2 absorber at a rate of 7.5 pounds per hour (lb/hr). Formaldehyde is the projected next largest HAP and is expected to account for approximately 5% for the total HAPs. DCC will be required to perform performance testing for acetaldehyde and formaldehyde upon start-up of the Project to confirm the HAP representations made in the permit application. Initial performance testing is also anticipated to confirm that the emissions do not pose an adverse risk to human health and the environment.

EPA Guidance provides that MACT control technology may be based on the specific design and process controls. The MACT controls are not dependent on a percent control or allowable ratio of acetaldehyde/HAP formation per unit of CO_2 capture (i.e., pounds of acetaldehyde/HAP per amount of CO_2 recovered) but are based on the design and process controls used to limit the formation of HAPs during operation. Future compliance

[5] See: https://www3.epa.gov/airtoxics/112g/112gpg.html
[6] DCC East Project LLC, Dakota Carbon Center CO_2 Separation and Purification Plan Permit to Construct Application. Appendix C. June 2, 2023.

assurance with the MACT determination will be based on initial performance testing, documentation of compliance with the absorber material selection, and continuous monitoring of operation of the intermediate cooling system to ensure that the represented level of HAP control is being achieved.

Should initial acetaldehyde and formaldehyde emission testing indicate results vary significantly from what was provided in the permit application, additional review/analysis may be required by the Department.

Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ establishes national emission limitations and operating limitations on HAPs emitted from RICE located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

Applicability and Expected Compliance

The Project has one engine (EU D03) subject to the requirements under this subpart. The requirements of Subpart ZZZZ for the engine are met by complying with the requirements of NDAC 33.1-15-12 [40 CFR 60], Subpart IIII.

W. NDAC 33.1-15-23 - Fees

This chapter requires a filing fee of $325 for permit to construct applications, plus any additional fees based on actual processing costs. The additional fees based on processing costs will be assessed upon issuance of the draft permit to construct.

The applicant has paid the $325 filing fee and may be required to pay the additional fees associated with the permit processing.

X. NDAC 33.1-15-24 - Standards for Lead-Based Paint Activities

The Project will not perform any lead-based painting and is therefore not subject to this chapter.

Y. NDAC 33.1-15-25 - Regional Haze Requirements

This chapter is specific to existing stationary sources or groups of sources which have the potential to “contribute to visibility impairment” as defined in Section 33.1-15-25-01.2. Existing stationary sources or groups of sources determined to contribute to visibility impairment may be required to implement emissions reduction measures to help the Department make reasonable progress toward North Dakota’s reasonable progress goals established in accordance with 40 CFR 51.308.

Applicability and Expected Compliance

The Project is a new source and based on low PTE of visibility impairing pollutants is not expected to contribute to visibility impairment. Therefore, the facility is not subject to the requirements of this chapter.

Summary:

A complete review of the proposed project indicates that the Project is expected to comply with the applicable federal and state air pollution rules and regulations. The Department will make a final recommendation on the issuance of a Permit to Construct for the Project following completion of a 30-day public comment period. The public comment period will begin on September 21, 2023, and end on October 21, 2023.

The Department will hold a public meeting followed by a public hearing in Center, North Dakota on October 19, 2023, for interested parties. Upon completion of the public comment period, the Department will address all comments applicable to the state and federal air quality rules and regulations and make a final determination regarding the issuance of a Permit to Construct for the Project.

Update post comment period:
A public comment period was held regarding the above draft Air Pollution Control Permit to Construct from September 21, 2023, through October 21, 2023. Comments were received from three parties which consisted of two individual commentors and Region 8 of the Environmental Protection Agency. This information is included in Appendix A – Public Record, attached to this permit document. The Department has provided written response to each applicable comment, also included in Appendix A.

The Department made logical-outgrowth changes from the draft Permit to Construct and Air Quality Effects Analysis that do not depart from the terms or substance of the proposed action.

Therefore, based on the comments received and Department responses, the Department recommends issuance of a final Permit to Construct for DCC Project East LLC to construct and initially operate the Dakota Carbon Center Carbon Dioxide Separation and Purification Plant.

Date of Draft Analysis: September 18, 2023
Date of Final Analysis: December 29, 2023

Analysis By:

David Stroh

David Stroh
Manager, Permit Program
Division of Air Quality

DES:

Appendix A – Public Record

A.1 – Public Hearing Notice

NORTH **Dakota** | Environmental Quality

Be Legendary.™

September 18, 2023

Mr. Gerad Paul
Secretary
DCC East Project LLC
5301 32nd Ave. S.
Grand Forks, ND 58201

Re: Air Pollution Control
Draft Permit to Construct No. ACP-18194 v1.0

Dear Mr. Paul:

Pursuant to the Air Pollution Control Rules of the State of North Dakota, the Department of Environmental Quality (Department) has reviewed the permit application dated June 2, 2023, and the revised modeling dated August 25, 2023, to obtain a Permit to Construct for initial construction and operation of the Dakota Carbon Center CO_2 Separation and Purification Plant to be located in Oliver County, North Dakota.

Before making final determination on the draft Permit to Construct, the Department must solicit public comment by means of the enclosed public notice. As indicated in the notice, the public comment period will begin on September 21, 2023, and end on October 21, 2023. The Department's analysis and a draft copy of the Permit to Construct may be found at https://deq.nd.gov/AQ/PublicCom.aspx. The documents will be posted on or before September 21, 2023.

All comments received will be considered in the final determination concerning issuance of the permit. You will be notified in writing of our final determination.

If you have any questions, please contact me at (701)328-5229 or destroh@nd.gov.

Sincerely,

David Stroh

David Stroh
Environmental Engineer
Division of Air Quality

DS:lc
Enc:
xc: Adam Eisele, EPA Region 8 (email - eisele.adam@epa.gov)
Julia Witteman, EPA Region 8 (email - witteman.julia@epa.gov)
Shannon Mikula, Minnkota Power Cooperative (email - smikula@minnkota.com)

NOTICE OF MACT APPROVAL AND INTENT TO ISSUE AN AIR POLLUTION CONTROL PERMIT TO CONSTRUCT

Take notice that the North Dakota Department of Environmental Quality (NDDEQ) proposes to issue an Air Pollution Control Permit to Construct to DCC East Project LLC in accordance with the North Dakota Air Pollution Control Rules. The proposed air pollution control permit is for initial construction and operation of the Dakota Carbon Center CO_2 Separation and Purification Plant to be located in Oliver County, North Dakota. Preliminary evaluations made by NDDEQ staff indicate that the proposed project will comply with all applicable Air Pollution Control Rules and is protective of human health and the environment.

The project required NDDEQ to perform a case-by-case maximum achievable control technology (MACT) determination. NDDEQ is providing an opportunity for public comment on the MACT determination consistent with 40 CFR 63.43(h). Details regarding the MACT determination can be found in the NDDEQ's Air Quality Effects Analysis.

An air dispersion modeling analysis was conducted to determine the cumulative impact from the project, existing Milton R. Young Station sources, other significant nearby sources within 50 kilometers, and background. Modeled impacts were below ambient air quality standards for each pollutant, as follows: 42% for the NO_2 1-hour standard, 6% for the NO_2 annual standard, 25% for the PM_{10} 24-hour standard, 55% for the $PM_{2.5}$ 24-hour standard, 46% for the $PM_{2.5}$ annual standard, 31% for the SO_2 1-hour standard, 5% for the SO_2 3-hour standard, 7% for the SO_2 24-hour standard, 6% for the SO_2 annual standard, 3% for the CO 1-hour standard, and 12% for the CO 8-hour standard. More detail regarding the projected modeled impacts can be found in the NDDEQ's Air Quality Impacts Analysis.

A 30-day public comment period for the proposed permit to construct and MACT determination will begin September 21, 2023, and end on October 21, 2023. Direct comments in writing, including Re: Public Comment Permit Number ACP-18194 v1.0, to AirQuality@nd.gov or the NDDEQ, Division of Air Quality, 4201 Normandy Street, 2nd Floor, Bismarck, ND 58503-1324. Emailed comments must be sent to the email address above to be considered. Comments must be received by 11:59 p.m. central time on the last day of the public comment period to be considered in the final permit determination.

In accordance with NDAC 33.1-15-14-02, a public information meeting and public hearing regarding issuance of the Air Pollution Control Permit to Construct will be held October 19, 2023, beginning at 5:30 p.m. CDT at the Betty Hagel Memorial Civic Center, 312 Lincoln Ave, Center, ND 58530.

The application, NDDEQ's Air Quality Effects Analysis, NDDEQ's Air Quality Impacts Analysis, and NDDEQ's proposed air pollution control permit are available for review at NDDEQ's office and on-line at http://deq.nd.gov/AQ/PublicCom.aspx. A copy of these documents may be obtained by writing to the Division of Air Quality or contacting David Stroh at (701)328-5229 or by email at destroh@nd.gov.

The NDDEQ will consider every request for reasonable accommodation to provide an accessible meeting facility or other accommodation for people with disabilities, language interpretation for people with limited English proficiency (LEP), and translations of written material necessary to access programs and information. Language assistance services are available free of charge to you. To request accommodations or language assistance, contact the NDDEQ Non-discrimination/EJ Coordinator at 701-328-5150 or deqEJ@nd.gov. TTY users may use Relay North Dakota at 711 or 1-800-366-6888.

Dated this 18th day of September 2023

James L. Semerad
Director
Division of Air Quality

A.2 – Invoice of Publication

North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, North Dakota 58503
Phone: 1-701-223-6397 Fax: 1-701-223-8185

INVOICE

October 16, 2023

Order: 23094ND0 Invoice# 13696

Attn: David Stroh
ND Department of Environmental Quality
4201 Normandy Street
Bismarck, North Dakota 58503-1324

Voice: Fax:
Email: DEQ-Invoice@nd.gov

Advertiser: Division of Air Quality
Brand:
Campaign
Client Order Number:
Amount Due: $87.74

Please detach and return this portion with your payment

Division of Air Quality Invoice# 13696 P.O.#: Client Order Number:

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Center Republican (Hazen, North Dakota)									
09/21/2023	107.00	Notice A Line	$0.82		$87.74	$0.00	(0.00%)	$87.74	
Caption: Notice of Mact Approval and Intent to issue an air pollution									
Subtotal:	107.00		$0.82	$0.00	$87.74	$0.00		$87.74	

Gross Advertising	$87.74	Total Misc	$0.00	Amount Paid	$0.00
Agency Discount	$0.00	Tax	$0.00	Adjustments	$0.00
Other Discount	$0.00	Total Billed	$87.74	Payment Date	
Service Charge	$0.00	Unbilled	$0.00	Balance Due	$87.74

If you'd like to pay your invoice online, go to www.ndna.com/billpay. We accept Visa/Mastercard. A 3% fee will automatically be added to your total. We also accept checks and ACH, with no additional fee added. Contact accounting@ndna.com for ACH information. Thank you!

A.3 – Registration List of Attendees

Public Hearing Sign-in Sheet **DCC East Project LLC** **ACP-18194 v1.0** **October 19, 2023**

Name (please print)	Address	Representing	Check Here to Testify
Shannon Mikula	28 Conklin Ave Grand Forks ND	DCC East Project LLC	
Andy Freidt	1307 Eagles View Place Bismarck ND	Minnkota Power	
Ben Fladhammer	3795 Haleigh Dr, Grand Forks, ND	Minnkota Power	
Chris Benner	2200 3rd Ave NE Beulah	Minnkota/IBEW 1593	✓
David Greeson	600 Country Club, Richmond, TX	Minnkota	
John Mahoney	PO Box 355 Center ND 58530	Center/Oliver County	
TROY KARLBERG	411 SHADY LANE, BISMARCK, ND 58501	MINNKOTA POWER	
Mike Hager	105 Dakota Ridge Underwood	BNI Coal	
Jaden Schmidt	2207 36th Ave SW Center	Oliver County	
Brita Endrud	1126 157th Ave NE	Minnkota Power	
[illegible]	3204 Bayshore [illegible]	Minnkota Power	
Casey Aktan	856 San Angelo Dr B.S	Minnkota Power	

Public Hearing Sign-in Sheet

DCC East Project LLC
ACP-18194 v1.0

October 19, 2023

Name (please print)	Address	Representing	Check Here to Testify
Darla Potter	4201 Normandy St Bismarck ND	NDDEQ	
Stacy Dahl	6020 E Prairiewood Dr, Grand Forks, ND	Minnkota Power	
Andrew Sorbo	418 Cole Creek Way NE, Thompson ND	Minnkota Power	
Scott Hopfauf	2767 Springfield St Bismarck ND	Minnkota Power	
Jim Semerad	4201 Normandy St. Bismarck	NDDEQ	
Karla Schulte	1680 40th Ave SW Center	Minnkota Power	
Doug Schetz	7618 Courtland Pl Bismarck ND	BNI Coal -	
Tucker O'Bren	2638 10th Ave SE Mandan	BNI Coal	
Casey Christmann	5219 Cornice Drive Bismarck ND	BNI Coal	
Craig Bleth	5300 Cornice Dr Bmk ND	Minnkota	
Cheryl Froehlich	3918 Lakewood Dr. SE Mandan, ND	BNI Coal	

Public Hearing Sign-in Sheet | **DCC East Project LLC** | **ACP-18194 v1.0** | **October 19, 2023**

Name (please print)	Address	Representing	Check Here to Testify
David Stroh	4201 Normandy St. Bismarck, ND 58503	NDDEQ	
Rama Cardwell	↓	NDDEQ	
Santosh Kumar	"	"	
Rhannon Thorton	"	NDDEQ	
Jon Madison	5407 Country Creek Dr. Bis, ND 58503	Minnkota Power	
John El-Hallal	4007 Oakwood Rock, Katy, TX	TC ENERGY	
Sally Johnson	Minot, ND - Washburn ND	Senator John Hoeven	
Tony Aman	Washburn ND	Minnkota Power	
Tim Hagerott	901 Longhorn drive, Bismarck, ND 58503	Minnkota Power	
Adam Undem	P.O. Box 272 Center ND 58530	BNI / IBEW	
Chris Simon	1935 46th Ave SW Hannover	BNI - Self	
Darrell Berger	1962 Hwy 48 Center	Co Commissioner	
Cheryl Hanggi	PO Box 28310, Center	~~Cen~~ BNI - IBEW	
Russ Keller		MINNKOTA	
Joe Roeder	PO Box 527 Hazen, ND	IBEW Local 1593	✓
Kevin Thomas	2628 Springfield St Bis	Myself	
Lukas Masseth	4503 Columbus Ct Mandan	BNI	
Dave Bergon	MPC Janitor	Just me	
Kane Kolcler	~~2~~3159 Hwy 25 Center	BNI	
JASON NELSON	705 14TH ST SE MANDAN	MPC	
Wyatt Eckroth	2490 High country Dr N	MPC	

A.4 – Hearing Transcript

DCC Hearing Testimony from 10/19/2023.

Jim Semerad: Good evening, everybody. My name is Jim Semerad. I'm the Director of Air Quality Division for the North Dakota Department of Environmental Quality, and I'll be acting today as the hearing officer for this public hearing. I will now open the public hearing portion of today's meeting at the Memorial Civic Center in Center, North Dakota. Let the record show that the time is approximately 6:16 p.m. on October 19th, 2023. This is the time and place that was scheduled for the public hearing for the DCC East Project, LLC Draft Air Pollution Control Permit to Construct pursuant to North Dakota Century Code Title 23.1 and North Dakota Administrative Code, Chapter 33.1-15-14. Anyone wishing to present verbal testimony on the draft permit to construct will be allowed to speak. Anyone presenting testimony is asked to state their name, their address, and the organization they represent, if any. Also, anyone presenting testimony is required to sign the registration sheet for the record. And I have those up front now. They're not no longer up. The purpose of the hearing is to receive input, such as additional data or viewpoints from interested parties, especially for those who have not or will not have the opportunity to submit written testimony. Both written and oral testimony will be considered equally. It will not be necessary to repeat testimony or comments that have been or will be submitted in writing, or that have been previously submitted during the hearing. I would like to emphasize that this hearing is not a question-and-answer session, and the department will not be responding to comments made during the hearing. However, if there's clarification needed on a proposed permit, we will be listening to your testimony and we'll be happy to provide clarification after the public testimony portion of the hearing has concluded. Also, please remember that the proposed permit only relates to health environmental impacts associated with issuing the permit to construct under the North Dakota Century Code, Title 23.1 and North Dakota Administrative Code chapter 33.1-15-14, relating to air quality controls and emissions. It does not relate to social and economic impacts or compatible land use. Therefore, we ask you to limit your comments to those concerns relating to the proposed air Permit to ensure that all interested parties have the opportunity to provide a comment for the record. Given that there's only two people that have signed up for comments, we likely won't have to impose a five-minute limit on comments that you may have, but we'll track that as time goes on. Otherwise, we'll ask that you limit your comments to five minutes to allow for everybody to give their testimony. Again, my name is Jim Semerad. If the time remains at the end, commenters who request more time may be allowed additional time to provide comments. It is important to note that the comment period remains open through October 21st, 2023, and written comments to be considered as part of the record may be submitted until then. Additional information relating to the proposed DCC East project can be found at the North Dakota Department of Environmental Quality web page at DEQ.nd.gov.

With that, when your name is called, we ask that you please come forward and speak into the microphone to ensure that your comments are recorded for the hearing record. First one is Chris Renner. Chris.

Chris Renner: My name is Chris Renner. Do I have to? My address here. My address is 2200 3rd Avenue Northeast. Beulah, North Dakota. I work for Minnkota Power Cooperative as an electrical instrumentation and controls technician. I am also a unit president of the IBEW 1593 here at Beulah. I personally support Project Tundra, and this is why. We are living in a world in which we are trying to reduce CO_2 emissions. This is the right thing to do, but we have to do it safely and intelligently. We have to be realistic. Milton R Young station is a coal powered thermal energy power plant. This nation's thermal energy sources such as natural gas, nuclear and of course coal, are what we call baseload energy and dispatchable energy sources. They can be turned on or off at will, within reason, and run at 100% output all day, every day. In other words, these thermal energy sources, such as Milton R Young Station are safe, predictable, and reliable. We cannot replace a megawatt of coal energy with a megawatt of intermittent wind energy and expect to keep the lights and heaters on during the cold winter months here in North Dakota and Minnesota. As I write this, I see on the Midcontinent Independent System Operator the Miso grid, that wind is at 2494MW. Last summer I saw the grid at 655MW. Today, as I review this, I see that the wind energy is at 16,679MW. While wind and solar both provide energy on occasion, it provides a roller coaster like swing and actual output due to a reliance on nature itself. Right now, it is a beautiful fall day, and there are only 68,975MW on the Miso grid as a whole. What happens in December and January when we run into a situation where there is no wind, there is over 100,000MW of load and we have eliminated too many baseload coal plants. When the next polar vortex hits, the wind towers will shut themselves down, produce nothing, and use power off the grid to run their onboard electric heaters. However, at this point in time, we still have just enough baseload coal to power the grid through these extreme weather conditions. Probably. This nation's electric utilities have been heavily regulated since at least 1968 by organizations such as the North American Energy Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC). These two organizations work together to provide standards to ensure just and reasonable rates, respond to emergencies or threats to the grid, and to ensure a safe and reliable electric grid. This is particularly important up here in the northern states during the winter months. As we shudder, more and more thermal energy sources such as coal, the production of electricity becomes much less stable. Due to the loss of dispatchable energy, we lose reliability. The price of energy fluctuates like a roller coaster, and we run into the threat of blackouts and brownouts in a region. To me, as far as reliability goes, this transition from thermal energy sources to renewables is going in the opposite direction of the reliable grid that NERC and FERC envision. There is nothing just in transitioning from reliable energy to potential blackouts and brownouts. It seems like we are going in a dangerous direction. I have seen several electric utilities promised to shutter their coal plants down for good, in favor of replacing them with solar. I have seen other utilities promise to shut down their coal in favor of wind energy. We need dispatchable energy, and we cannot afford to lose more than we have already lost. We can turn our thermal energy sources on at will, and we can control the output in a coal fired plant with a nameplate rating of, say, 700MW. We can expect 700MW out of that plant between 92 and 95% of the year, all day, every day. With wind and solar, we are stuck with what nature tells us we get. A 700-megawatt wind or solar plant may, on rare occasions, put out 700MW, but how often can one rely on that? Like I said earlier, the entire Miso grid may provide 655MW, or it may be 17,000MW. That is a very substantial swing. We need reliability on the grid and Milton R Young station, provides that.

It seems that as these utilities shutter their thermal plants and replace them with green energy, they are expecting or hoping to buy energy from their neighboring utilities when they run into shortfalls of energy of their own. The problem lies in the fact that their neighbors are also planning on shuttering their coal in favor of wind and solar. The question is, who is going to be responsible for the blackouts and brownouts in the ice-cold Midwest when we run out of wind and solar? Are the utilities themselves going to be held accountable? Are the politicians that help force their hand into closing their thermal energy sources going to be held accountable? Are the banks that refuse to give loans to coal companies going to be held accountable? You know, you may hear arguments that battery banks are the future, but why would we want to spend the money, time, and resources on batteries at this point when we do not produce enough green energy to provide the grid, let alone power the grid and charge a giant battery bank? What we need is reliability in energy production. The coal industry is required by regulation to maintain a stockpile of at least two weeks of fuel stockpiled in the event of a disruption in fuel supply. I don't know how many battery banks or the size of these battery banks we would need to power the grid for two weeks during the winter, when the daily grid demand is over 100,000MW.

Another argument you may hear in opposition to Project Tundra is that coal is expensive. In a way it is, I suppose, but there are many factors that make it so. One of the major contributing factors in the price of coal is the fact that coal is forced to reduce load or shut down completely when the wind is blowing, or the sun is shining. This causes a loss of income in the coal sector. Imagine if Napa Auto Parts were banned from selling their goods unless Rock auto could not keep up with demand. Napa would have no choice but raise their prices or just go under. I have seen some people call Project Tundra a waste of money. How can anyone truly consider investing in clean, reliable energy a waste of money? Again, reliability is key. Doing nothing to preserve our baseload and dispatchable power sources means a future of blackouts and brownouts due to intermittent energy sources. Doing nothing is a danger to everyone that relies on the grid. Sometimes innovation and reliability are expensive, but necessary. In fact, the EPA administrator, Michael Regan himself sees huge potential for carbon capture here in North Dakota. Minnkota also spends countless dollars and hours working to meet and exceed all governmental safety, reliability, and environmental regulations. I have heard people call the coal industry names such as Dirty coal, Obsolete Coal, Killer coal, and I have heard the same people call the industry as a whole, greedy coal. You know, I don't know if we can classify modern cooperatives like Minnkota greedy when we spend so much time and revenue working to eliminate our emissions and safeguard our environment. On a separate note, I have seen state governments promise to abolish the sales of gas cars in favor of electric cars. As a nation, we are looking at adding countless megawatts of load to our already strained grid. We need to keep our powerful and reliable sources of baseload and ready to dispatchable thermal utilities such as Milton R Young station operating if we want to keep the furnaces running when it is 20 below outside. From the day I first started work at Minnkota, Minnkota has already worked hard and spared no expense to meet and exceed all rules of law, as well as all safety and environmental regulations. There is no doubt in my mind that Minnkota will work very hard to meet and exceed all safety regulations and standards to make tundra a safe, successful, and innovative project. So, with Project Tundra, we will be eliminating many tons of CO2 from entering the atmosphere while providing the safe, stable and reliable grid that the member owners and users and our many regulatory agencies demand. Tundra is a great solution for a climate issue. It is my hope that Minnkota may one day become not only a producer of reliable energy that it already is, but also a producer of energy with zero carbon emissions or perhaps a negative carbon producer, meaning we eliminate more carbon from the atmosphere than we actually create.

Thank you.

Jim Semerad: Thank you, Chris. Next is Joe.

Joe Roeder: Hi, my name is Joe Roeder. I'm a representative of the International Brotherhood of Electrical Workers Local Union 1593. We represent over a thousand members in the western part of the state here in this community. The industries we represent are mostly coal based, but we also have gas, Dakota Gas. We also have a wind farm by Max North Dakota and a nursing home in Beulah. Uh, we represent the workers at Milton R Young station in the adjacent coal mine of BNI Coal. We're here today to pledge our support for this project. We believe that Minnkota has done their due diligence, and we believe this project is a safe and efficient project that can be developed. And we would urge you to pass this air permit in their favor. We believe it'll bring a lot of economic benefit to this community and to all the workers that are represented here. That's all I have to say. Thank you.

Jim Semerad: That's all I see that signed up to testify. Is there anybody else who would like to testify?

Last call on testifying. Okay. Again, we want to say thank you all for coming. All information gathered at this hearing will be provided to the Department of Environmental Quality, which is the decision-making body. The record will be held open for written comments through October 21st, 2023. And at this time, I close the hearing on the Department of Environmental Quality's Draft Air Pollution Control Permit to Construct for the DCC East project. The hearing is closed at 6:33 p.m. Thank you all.

A.5 – Comments Received During the Public Comment Period

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

Ref: 8ARD-PM

David Stroh
North Dakota Department of Environmental Quality, Division of Air Quality
4201 Normandy Street, 2nd Fl
Bismark, ND 58503-1324

Re: EPA Comments to Dakota Carbon Center East Project LLC, Permit to Construct

Dear David Stroh:

This letter is in response to the North Dakota Department of Environmental Quality's (NDDEQ) public notice of the draft permit to construct for the Dakota Carbon Center East Project LLC (DCC). The NDDEQ's public comment period for this permit ends October 21st, 2023.

After reviewing the draft permit to construct, EPA submits the following comments. As explained in more detail below, these technical comments are related to source aggregation, incorporation by reference, monitoring, recordkeeping, reporting requirements, modeling found in the permit and corresponding air quality effects analysis, and Clean Air Act (CAA) Section 112(g).

<u>Comments Related to Aggregation</u>

The DCC Air Quality Effects Analysis (AQEA) discusses the potential of aggregating the DCC facility with the existing Milton R. Young (MRY) Station coal-fired power plant. DCC is located next to the existing MRY facility. DCC will capture, purify, and sequester up to 13,000 tons per day of CO_2 from MRY's boilers (MRY Unit 1, MRY Unit 2). The AQEA states:

> *DCC's Project will be considered a separate stationary source from the MRY Station for the purposes of the applicable air pollution control rules (40 CFR Part 63 and 40 CFR Part 70). Part 63 requires two criteria to be met for two (or more) sources to be considered a single major source, the sources must be "located within a contiguous area and under common control". Part 70 contains the same first two criteria and adds a third criteria, that sources must belong to the same major industrial grouping. DCC will be responsible for operational control of the Project, including control over air emitting activities that affect permit compliance (i.e., not under common control), and the owner of MRY Station will not hold a majority ownership in DCC. DCC's Project has standard industrial classification (SIC) code 2813 compared to MRY Station SIC code of 4911 (i.e., do not belong to the same industrial grouping). DCC will be adjacent to MRY Station, so the facilities will be located within a continuous area. Of the Part 63 and Part*

70 criteria the Project only meets one of the necessary criteria; therefore, the Project is considered a separate source.

AQEA at page 1

Region 8 has reviewed the NDDEQ's discussion of the DCC project source determination and has concerns about the record of support for the decision that the DCC project and MRY facility should be considered separate facilities. The NDDEQ's analysis is correct in that both 40 CFR part 70 and 40 CFR part 63 have separate definitions of what constitutes a major source for each regulation and that if the case-specific facts support that only one of the necessary criteria in either definition is met then the two sources in question should be considered separate stationary sources for the purposes of those regulations. However, as laid out in the following discussions, the EPA recommends enhancement of the permit record to support the NDDEQ's conclusions.

The draft permit action available for EPA review and for public comment is a permit to construct. Therefore, the EPA believes the NDDEQ should first determine whether these two entities should be considered part of the same "stationary source" under the New Source Review (NSR) preconstruction permit programs under title I of the CAA. This determination will dictate whether or not the project requires a permit to construct a minor or major new source or a minor or major "modification" to an existing source. That exercise will inform whether the facilities are considered part of the same "major source" under title V and part 63 of the CAA and any required application of those programs.

Under the federal rules governing both the NSR and title V permitting programs, entities may be considered part of the same "stationary source" or "major source" if they (1) belong to the same industrial grouping: (2) are located on one or more contiguous or adjacent properties: and (3) are under the control of the same person (or persons under common control).

The NDDEQ's AQEA indicates that the DCC and MRY facilities are located on contiguous and adjacent properties. On the question of common control, NDDEQ has described DCC and MRY as having separate controlling entities. EPA has long determined that establishing the relationship for common control is done on a case-by-case basis. The 2018 Meadowbrook source determination[1] states:

For the reasons discussed further in the Attachment, the agency believes clarity and consistency can be restored to source determinations if the assessment of "control" for title V and NSR permitting purposes focuses on the power or authority of one entity to dictate decisions of the other that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements.

Meadowbrook at page 2.

A review of available information on the internet indicates that MRY is directly owned by Minnkota Power Cooperative.[2] Further, the same Minnkota Power Cooperative website contains links to "Project Tundra".[3] Project Tundra would "retrofit the Milton R. Young Station with CO_2 capture technology" and "Final air permits are being pursued and are anticipated in 2023".

---

[1] https://www.epa.gov/sites/default/files/2018-05/documents/meadowbrook_2018.pdf, accessed October 16, 2023

[2] https://www.minnkota.com/minnkota-website/our-power/coal, accessed October 16, 2023.

[3] https://www.projecttundrand.com/about, accessed October 16, 2023.

Further, the June 2, 2023 permit application refers to the proposed project as Project Tundra. This information may suggest the that the Minnkota Power Cooperative has control over both the MRY and DCC projects. The EPA recommends that the NDDEQ enhance the permit record with additional information supporting the conclusion that a common control relationship does not exist between the DCC and MRY facilities.

The third source determination criteria is whether both facilities belong within the same industrial grouping, commonly indicated by Standard Industrial Classification (SIC) code. The NDDEQ states that DCC has the SIC code of 2813 and MRY has the SIC code of 4911. The preamble to the 1980 PSD rule discussed the EPA's view on how to evaluate what SIC code applies to facilities that support the operation of a primary facility. The preamble[4] to the rule, discusses that "each source is to be classified according to its primary activity, which is determined by its principal product or group of products produced or distributed, or services rendered. Thus, one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC code. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product."

The AQEA states:

> *The Project will be located adjacent to the existing Milton R. Young (MRY) Station and is designed to capture, purify, and sequester up to 13,000 tons per day (~4.75 million tons per year) of CO_2 from MRY Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2).*

The EPA recommends that the NDDEQ include additional information in the permit record to support the conclusion that a support facility relationship does not exist between the DCC project and MRY. Recommended details to consider or clarify in supplementing the permit record on the appropriate industrial classification for DCC includes the role of DCC and its principal product produced or distributed (if any), or services rendered, and the source of power to operate DCC.

If upon additional review, the NDDEQ determines that that the MRY and DCC facilities should be aggregated as one source under the CAA Title I permitting programs, (and by extension 40 CFR Part 63 and 40 CFR Part 70) then the EPA recommends the NDDEQ modify the permit and supporting documentation according to the North Dakota State Implementation Plan.

Comments Related to Incorporation by Reference

Incorporation by reference into permits is an allowable way for permitting authorities to cite requirements applicable to permitted sources. One of the earliest documents recognizing the utility of this process was the March 5, 1996, *White Paper Number 2 for Improved Implementation of The Part 70 Operating Permits Program* (*White Paper 2*).[5] This document states:

> *Citations, cross references, and incorporations by reference must be detailed enough that the manner in which any referenced material applies to a facility is clear and is not*

[4] 45 FR at 52694

[5] https://www.epa.gov/sites/default/files/2015-08/documents/wtppr-2.pdf, accessed October 16, 2023, accessed October 16, 2023.

reasonably subject to misinterpretation. Where only a portion of the referenced document applies, applications and permits must specify the relevant section of the document. Any information cited, cross referenced, or incorporated by reference must be accompanied by a description or identification of the current activities, requirements, or equipment for which the information is referenced.

White Paper 2 at 37. Further, the EPA stated:

Incorporation by reference in permits may be appropriate and useful under several circumstances. Appropriate use of incorporation by reference in permits includes referencing of test method procedures, inspection and maintenance plans, and calculation methods for determining compliance. One of the key objectives Congress hoped to achieve in creating title V, however, was the issuance of comprehensive permits that clarify how sources must comply with applicable requirements. Permitting authorities should therefore balance the streamlining benefits achieved through use of incorporation by reference with the need to issue comprehensive, unambiguous permits useful to all affected parties, including those engaged in field inspections.

White Paper 2 at 38.

The EPA has also addressed the subject of incorporation by reference more recently in Administrative Orders for title V operating permit Petitions to Object. The March 18, 2022, Exxon Baytown Order[6] and the March 10, 2020 Waha Gas Plant Order[7] both address the issue and cite to *White Paper 2* as the basis for establishing the appropriate methodologies in the correct us of incorporation by reference.

In the DCC permit to construct there are instances were only a portion of the referenced applicable requirement applies and the permit does not specify that portion. Condition II.C.1 of the draft permit incorporates by reference 40 CFR Part 60 Subpart IIII. While Condition II.C.1 does not state which emission unit at the proposed facility is subject to the cited Subpart, the table above Condition II.C.1 does indicate the that the emergency diesel fire pump engine is subject to the Subpart. However, neither Condition II.C.1 nor the table provide enough information for the reader to determine which emission limit and associated monitoring, recordkeeping and reporting applies to the emission unit. The level of incorporation by reference used in the draft permit is insufficient for the applicant and public to determine what standard applies to the unit and how the source is to achieve compliance with that standard.

In addition, Condition II.D.1 incorporates by reference 40 CFR Part 63 Subpart ZZZZ. Unlike the previous Condition, this Condition does not have any associated Table stating which unit the standard applies to, nor does the Condition itself state which emission unit is subject to the standard. It is up to the reader of the permit to assume it is the emergency diesel fire pump engine, and similar to Condition II.C.1, there is no information available in the permit to determine which of the Subpart ZZZZ standards, monitoring, recordkeeping or reporting apply.

---

[6] https://www.epa.gov/system/files/documents/2022-02/etc-waha-order_1-28-22.pdf, accessed October 16, 2023.
[7] https://www.epa.gov/system/files/documents/2022-02/etc-waha-order_1-28-22.pdf, accessed October 16, 2023.

This level of incorporation by reference is similarly insufficient for the applicant and public to determine which standard applies and what are the associated compliance requirements.

EPA recommends that the NDDEQ revises the draft permit to construct to include which portions of the associated regulations apply to each permit condition and to clearly state the standard or associated limit and compliance requirements. The references should be unambiguous and useful to all affected parties.

Comments Related to the Ambient Air Boundary used in Modeling

Appendix 2 of the AQEA document supplied in the record discusses the air dispersion modeling done to demonstrate compliance with the North Dakota Ambient Air Quality Standards. As a part of this document, the applicant included site layout maps and maps expressing a visual representation of the established air dispersion modeling receptor grid.

These maps contain the ambient air boundary for the MRY facility. The EPA defines ambient air within 40 CFR 50.1(e) as "that portion of the atmosphere, external to buildings, to which the general public has access". The EPA has long followed a policy that allows for the exclusion of certain areas, outside of a building, from ambient air. As described in a 1980 letter from then-Administrator Douglas Costle to Senator Jennings Randolf, this "exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which the public is precluded". The December 2019 *Revised Policies on Exclusions from "Ambient Air"*[8] continues to support that concept of exclusions from ambient air and establishes what requirements are needed to demonstrate that the public is precluded.

Figure A-1 in Appendix 2 of the AQIA establishes what appears to be an ambient air boundary for the facility that is used to delineate where the air dispersion modeling receptor grid is located. This receptor grid is shown in Figure A-4 and excludes the area inside the defined ambient air boundary.

However, in the permit's June 2, 2023 application, in Figure 2-1, the larger ambient air boundary contains a smaller defined area labeled as the DCC Separation and Purification Plant and locates the MRY facility's Unit 1 and Unit 2 in relationship to the DCC facility. The larger ambient air boundary area used in the air dispersion modeling process to establish the modeling receptor grid appears to be the MRY ambient air boundary and the DCC ambient air boundary, according to Figure 2-1 appears to be a smaller area located within the MRY boundary. As it contains MRY Unit 1 and Unit 2, this would appear to be the MRY ambient air boundary.

The EPA provided guidance for the treatment of ambient air in a June 22, 2007 memorandum to the Regional Air Division Directors.[9] With respect to a particular source, EPA's practice has been to exempt an area from ambient air when the source (1) owns or controls the land or

---

[8] https://www.epa.gov/sites/default/files/2019-12/documents/revised_policy_on_exclusions_from_ambient_air.pdf, accessed October 16, 2023.

[9] *Interpretation of "Ambient Air" In Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD)*, June 22, 2007, available at https://www.epa.gov/sites/default/files/2015-07/documents/leaseair.pdf, accessed October 16, 2023.

property; and (2) precludes public access to the land or property using a fence or other effective barrier. As discussed above within the aggregation section, the permit states that DCC and MRY are separate facilities and are not under common control. However, for the purposes of modeling, areas are exempted because they are owned or controlled by the same party. Both scenarios are unlikely to be both simultaneously true. The EPA also discussed situations where a lessor/lessee situation exists and one facility is nested within the ambient air boundary established by the other in the June 22, 2007 guidance. This discussion may be useful in determining the extent and location of ambient air for the DCC project.

EPA recommends that the NDDEQ review the cited documents and confirm that the ambient air boundary and associated receptor grid used in the air dispersion modeling for the DCC project is accurate based on definitions of ambient air and the boundary that DCC establishes. If that boundary is different than the one used to define the model's receptor grid, the EPA recommends that the NDDEQ or the applicant rerun the model to determine no NAAQS concerns exist.

Comments Related to CAA Section 112(g)

The EPA has concerns with the CAA section 112(g) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs) in the permit application, particularly regarding the use of acetaldehyde as a surrogate pollutant for all organic HAPs. The DCC permit also has emissions testing for acetaldehyde only, and asserts it is a suitable surrogate for all HAPs. In a MACT analysis, a surrogate is allowed when the control of the surrogate indicates a similar or identical control of the other pollutants. In this case, acetaldehyde and amines (including nitrosamines) exhibit different behaviors under different control scenarios. The effectiveness of controls for amine HAPs should therefore be evaluated separately from the effectiveness of controls for aldehyde HAPs (acetaldehyde and formaldehyde). The EPA recommends that the NDDEQ address this deficiency in the MACT analysis.

Conclusion

We are committed to working with the NDDEQ to ensure that the final Permit to Construct is consistent with all applicable EPA-approved North Dakota state implementation plan requirements.

If you have questions or wish to discuss this further, please contact me, or your staff can contact Donald Law at (303) 312-7015 or law.donald@epa.gov.

Sincerely,

Recoverable Signature

X Adrienne Sandoval

Signed by: Environmental Protection Agency

Adrienne Sandoval
Director
Air and Radiation Division

A.5.i – DCC East Project LLC Response to Comments

5301 32nd Ave. South
Grand Forks, ND 58201
Phone 701.795.4000

DCC EAST PROJECT LLC

November 16, 2023

Jim Semerad, Director, Division of Air Quality
David Stroh, Environmental Engineer
North Dakota Department of Environmental Quality
4201 Normandy Street, 2nd Floor
Bismarck, ND 58503-1324

Re: Application of DCC East Project LLC for Permit to Construct No. ACP-18194 for Dakota Carbon Center CO_2 Separation and Purification Plant

Dear Mr. Semerad and Mr. Stroh:

Please accept this letter as a further supplement to the record for the application of DCC East Project LLC (DCC East) for Permit to Construct No. ACP-18194 for the Dakota Carbon Center CO_2 Separation and Purification Plant (the DCC Facility) in Oliver County, North Dakota. This letter responds to the comments received from EPA Region 8 on the Draft Permit to Construct. DCC East does not intend to waive confidentiality privilege for the underlying agreements discussed in this response letter that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2. DCC East offers the following discussion of agreements to further supplement the record subject to confidentiality treatment of the agreements.

Comments related to Aggregation

DCC East Response: In its comments, EPA Region 8 recommended that NDDEQ include additional information in the permit record to support the separate source determination that NDDEQ made for the DCC Facility under the New Source Review (NSR) preconstruction permitting program. As correctly noted by EPA Region 8, NDDEQ found the existing Milton R. Young (MRY) Station and the proposed DCC Facility to be separate sources based on its determinations that (1) the two facilities are not under the control of the same person (or persons under common control) and (2) the two facilities do not belong to the same industrial grouping (and one entity is not support facility for the other). NDDEQ summarized its review of the application in the Air Quality Effects Analysis (AQEA) stating that:

> *DCC will be responsible for operational control of the Project, including control over air emitting activities that affect permit compliance (i.e., not under common control), and the owner of MRY Station will not hold a majority ownership in DCC.*

DCC's Project has standard industrial classification (SIC) code 2813 compared to MRY Station SIC code of 4911 (i.e., do not belong to the same industrial grouping).

Based on these findings, NDDEQ concluded that two of the three criteria that are necessary to find that the two facilities are located at the same stationary source are absent and therefore aggregation would not be appropriate. DCC East supports NDDEQ's conclusion and provides the following additional responsive information to support the permit record.

Common Control. The MRY Station and the proposed DCC Facility are not under the control of the same person or persons under common control. In its April 30, 2018 *Meadowbrook* determination, EPA established that the focus of the common control analysis is on whether one entity has power or authority to dictate decisions over any aspect of another entity's operations that could affect the applicability of, or compliance with, permitting requirements.[1] Neither owner of the electric generating units at the MRY Station will have such power or authority over the proposed DCC Facility.

First, the MRY Station and the proposed DCC Facility are not owned by the same person. The MRY Station consists of a two-unit electric generation plant, Unit 1 owned by Minnkota Power Cooperative, Inc. (Minnkota), and Unit 2, owned by Square Butte Cooperative (Square Butte). Minnkota operates both units at the MRY Station. In contrast, the proposed DCC Facility will be owned and operated by a separate legal entity named DCC East.

Second, the MRY Station and proposed DCC Facility are not owned by persons under common control. If one person owns a majority interest in two facilities, or the persons owning the two facilities, then it may be possible for a reviewing agency to presume that the two facilities or persons are under common control.[2] But that is not the case here. Neither Minnkota nor Square Butte will own a majority interest in the DCC Facility or DCC East. Instead, a majority interest in both the DCC Facility and DCC East will be owned by an unrelated third party or third parties, including TC Energy Carbon Capture LLC, which is a subsidiary of TC Energy Corporation.

The DCC Facility is being developed pursuant to the terms of commercial agreements, including a Joint Development Agreement (JDA), dated June 23, 2023, between Minnkota and TC

---

[1] EPA Letter: William L. Wehrum, Assistant Administrator, Office of Air and Radiation, U.S. Environmental Protection Agency, to the Honorable Patrick McDonnell, Secretary, Pennsylvania Department of Environmental Protection (April 30, 2018) (hereinafter "*Meadowbrook* Letter").

[2] EPA Region 8 has found that two wholly or majority-owned subsidiaries are "persons under common control" and thus meet that criterion for source determinations. EPA stated that it expects that common ownership inherently involves the parent company's ability to dictate, at a certain level, a substantial portion of the activities of its subsidiaries in a manner that could impact compliance with, or the applicability of, air permitting requirements. Thus, based on the principles outlined in the Meadowbrook and Ameresco letters, common ownership is a sufficient basis for determining that multiple entities are "persons under common control…given that common ownership inherently involves a significant amount of control, the EPA thinks it would be reasonable for permitting authorities to rely on the existence of common ownership when determining entities are "persons under common control" rather than undertaking a more detailed analysis." EPA Region 8, *Single Source Determination for Jaques Compressor Station,* (2019).

Energy Carbon Capture LLC (TC Energy CC).[3] These agreements provide for TC Energy CC's majority ownership share of the DCC Facility through its equity interest in DCC East. Accordingly, the owner of one unit at the MRY Station, Minnkota, will at most own a minority interest in the proposed DCC Facility and DCC East. Given this project development structure, the two facilities are not owned by persons under common control.

EPA Region 8 included in its comment letter references to "Project Tundra" on Minnkota's website to suggest that Minnkota has control over both the MRY Station and the DCC Facility. Information contained on the website does not alter the structure reflected in the recently executed commercial agreements. Rather, the Project Tundra website reflects Minnkota's historical role as a project sponsor to lead the development and advancement of CCS technology in the electric generation industry. Minnkota has been promoting Project Tundra since 2015, first acting as host site for carbon capture research and geologic sequestration characterization efforts under many federal and state funded research programs. However, a CO_2 gas separation plant of the economic and financing scale and requirements such as this cannot be constructed and operated primarily by Minnkota. Minnkota has been transparent throughout Project Tundra's development by clearly communicating to its members, the community, and stakeholders that Minnkota cannot and will not be a majority owner of the proposed DCC Facility. Through project financing, equity, and debt investment, Minnkota will own no more than a minority interest, as is confirmed by the June 28, 2023 press release on that website, announcing the foregoing commercial agreements with TC Energy, among others, to move "Project Tundra into its final stage of project development."

Finally, neither Minnkota nor Square Butte will have the power or authority to dictate decisions over any aspect of the DCC Facility's operations that could affect the applicability of, or compliance with, permitting requirements.[4] The DCC Facility will be operated and managed by DCC East, as confirmed by the commercial agreements between Minnkota and TC Energy CC, including the JDA and a separate Flue Gas Supply Agreement (FGSA), dated June 23, 2023.[5] These agreements also confirm that DCC East holds all environmental responsibility and liabilities, including the obligation to obtain permits and authorizations under and comply with all environmental requirements for the emissions generated by proposed DCC Facility. Contractual provisions such as these further highlight the absence of any common power or authority over the facilities relevant to the common control test articulated by EPA in the *Meadowbrook* letter.

Same Industrial Grouping. EPA Region 8 recommended providing additional details for the permit record regarding the role of DCC East and its principal product produced or distributed (if any) or services rendered, and the source of power to operate the DCC Facility. NDDEQ's

[3] DCC East identifies and provides information from confidential commercial agreements for the limited purposes of supporting the permit record. DCC East does not intend to waive any claim to confidentiality for the referenced agreements that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2.

[4] *Meadowbrook* Letter.

[5] DCC East identifies and provides information from confidential commercial agreements for the limited purposes of supporting the permit record. DCC East does not intend to waive any claim to confidentiality for the referenced agreements that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2.

permit record correctly documents the industrial grouping for MRY as 4911 (Electric Services) and for the proposed DCC Facility as 2813 (Industrial Gases). The operations of the MRY Station and the DCC Facility are classified under different two-digit SIC codes, and therefore this source determination criterion is also not met. As noted in EPA Region 8 comments, EPA has stated in guidance that one source classification may encompass both primary and support facilities, even when the latter includes units with a different two-digit SIC code: "[s]upport facilities" that "convey, store, or otherwise assist in the production of the principal product or group of products produced or distributed, or services rendered" should be considered under one source classification.[6]

In this case, no such support facility relationship exists because the facilities produce different principal products. Minnkota exists for the sole purpose of meeting the electricity needs of rural member cooperatives in eastern North Dakota and northwestern Minnesota. The MRY Station is part of Minnkota's portfolio of generation assets that have and will continue to be used to provide electricity in Minnkota's service area. The operation of the MRY Station will not be dependent on or supported by the construction and operation of the DCC Facility. The primary product of the MRY Station is electricity, and MRY will continue to provide this electrical product irrespective of the DCC Facility.

In contrast, the principal product of the DCC Facility is a concentrated CO_2 gas stream.. The concentrated CO_2 gas will be sequestered to generate tax credits for the benefit of the owners of DCC East. The DCC Facility will manufacture the CO_2 product from flue gas that is fully authorized to be emitted to the atmosphere from the MRY Station. The proposed DCC Facility will be powered by electricity from Minnkota via an arms-length contractual arrangement.

The relationship of the MRY Station and the DCC Facility is similar to the relationship of Red Cedar Gathering Company's Arkansas Loop and Simpson Treating Plant and a proposed carbon capture facility evaluated by EPA Region 8 in its August 24, 2023 determination. EPA Region 8 concluded there that "the facts do not establish a support relationship of the proposed new CO_2 Plant to the Arkansas Loop and Simpson Treating Plants." In *Red Cedar*, EPA Region 8 noted that the permit for the treating plants did not prohibit venting of waste CO_2 gas, stating "[i]n that sense, while an environmental benefit, in taking the waste CO_2 gas from the treating plants to make a secondary product, the CO_2 Plant would not convey, store, or otherwise assist in the production of the principal product for the treating plants." Here, the MRY Station air permit does not prohibit venting of the MRY Station flue gas, and in taking the CO_2 from MRY Station to make a product, DCC would not be conveying, storing, or assisting in the production of the "principal product" for MRY Station. EPA Region 8 also emphasized the established nature of Red Cedar, highlighting that if the carbon capture facility is not built, Red Cedar would continue operating as it has for years. EPA Region 8 stated that "[e]xisting EPA policy...does not reasonably support consideration of an existing source long established with a primary activity that supplies a waste gas from that activity to be considered a support facility of a proposed new source." Likewise,

[6] Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans, 45 Fed. Reg. 52,676, 52,695 (August 7, 1980).

MRY Station went into service decades ago, and MRY Station will continue to operate, even if the DCC Facility is not built. No support facility relationship exists between MRY Station and the DCC Facility based on these facts and Region 8 precedent.

Facility Emissions. EPA Region 8 also stated in its comments with respect to aggregation that "[t]his determination will dictate whether or not the project requires a permit to construct a minor or major new source or a minor or major 'modification' to an existing source." That consequence is not accurate in this case. Even if the DCC Facility had been improperly evaluated under NSR permitting program as a modification to the MRY Station, only a minor modification permit would have been required. The DCC Facility potential to emit for each regulated NSR pollutant does not equal or exceed the significant amount for that pollutant under the modification thresholds found at 40 CFR § 52.21(b)(23).

Conclusion. NDDEQ properly determined the MRY Station and the proposed DCC Facility to be separate sources for NSR permitting purposes based on the information in the record.

Comment: Ambient air boundary

DCC Response: In its comments, EPA Region 8 recommended that NDDEQ review the cited documents and confirm that the ambient air boundary and associated receptor grid used in the air dispersion modeling for the DCC Facility for accuracy. If that boundary is different than the one used to define the model's receptor grid, then EPA recommended that the NDDEQ or the applicant rerun the model to confirm that no NAAQS concerns exist.

The permit record confirms that the use of the property boundary of the MRY Station as the ambient air boundary is appropriate. EPA defines "ambient air" as "that portion of the atmosphere, external to buildings, to which the general public has access."[7] Applying this definition, EPA has stated "that portion of the atmosphere over land owned or controlled by the stationary source may be excluded where the source employs measures, which may include physical barriers, that are effective in precluding access to the land by the general public."[8]

Minnkota maintains a fenced physical barrier preventing unauthorized entry of the public into the MRY Station. DCC East used the fenced MRY Station property boundary in its modeling demonstrations. The fenced barrier will remain after the start-up of the DCC Facility. The proposed operation plan for the DCC Facility consists of use of the existing MRY Station security gate for designated access across Minnkota property to the DCC Facility secured site. The DCC Facility will be located on leased property, adjacent to the MRY Station, and will be considered "nested" within the footprint of Minnkota's access restrictions. The MRY Station is a critical infrastructure site and requires strict adherence to security protocols to mitigate access risk. As

[7] 40 CFR 50.1(c).
[8] EPA Memorandum: Andrew R. Wheeler, U.S. Environmental Protection Agency, to Regional Administrators, regarding Revised Policy on Exclusion from "Ambient Air" (December 2, 2019).

such, authorized employees and contractors of the DCC Facility will be required to comply with security and access requirements of the MRY Station and invitee practices and policies.

Given the physical barrier and access control of Minnkota for the MRY Station, there is no access of the general public. Moreover, even the parcel leased to DCC East is not ambient air to Minnkota as lessor for the evaluation of MRY Station emissions. EPA has acknowledged that ambient air over land that a lessor owns and leases to a lessee is not ambient air to the lessor:

> *When two (or more) companies operate separate sources on property owned by one company and leased in part to the other, and the lessor retains control over public access to the entire property and actually maintains a physical barrier around it to preclude public access – the air over the entire property (including the leased portion) is not ambient air to the lessor.*[9]

For this reason, the DCC East leased parcel is not ambient air for any evaluation of the emissions from the MRY Station. This is true both for the direct emissions from MRY Station and the indirect, pass-through flue gas that will exit the new absorber stack following processing in the proposed DCC Facility. The FGSA confirms that title to the flue gas from the MRY Station will remain in the name of the MRY owners when the flue gas is emitted from the absorber stack.[10] Consequently, the modeling of the impacts of the pass-through emissions from the Station may use the MRY Station boundary as the ambient air boundary for NAAQS modeling. While the DCC Facility will also emit pollutants that are not considered pass-through emissions, the modeled impacts of those pollutants are not expected to be materially affected by a change in the ambient air boundary, given that they represent such a small percentage of emission rates modeled.

Comment: Case-by-Case MACT

DCC Response: EPA Region 8 noted that a surrogate is allowed when the control of the surrogate indicates a similar or identical control of the other pollutants. In this case, EPA Region 8 commented that acetaldehyde and amines may exhibit different behaviors under different control scenarios, and that the effectiveness of controls for amine hazardous air pollutants (HAPs) should therefore be evaluated separately from the effectiveness of controls for aldehyde HAPs.

As described in section 7.1 of the Case-by-Case MACT Analysis, aldehydes, including acetaldehyde and formaldehyde, are expected to make up a large majority of the HAP emissions from the carbon absorber column, accounting for more than 98 percent of all HAP emissions (MACT Analysis, Table 2-1). The remaining HAP constituents, accounting for approximately 2

[9] EPA Memorandum: Stephen D. Page, Director, Office of Air Planning & Standards, U.S. Environmental Protection Agency, to Regional Air Division Directors (June 22, 2007).

[10] DCC East identifies and provides information from confidential commercial agreements for the limited purposes of supporting the permit record. DCC East does not intend to waive any claim to confidentiality for the referenced agreements that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2.

percent of total HAP emissions, are generally classified as amines. An amine is a derivative of ammonia in which one, two, or all three hydrogen atoms are replaced by hydrocarbon groups.

Control systems and technologies available to reduce HAP emissions from the carbon absorber column were evaluated in the MACT Analysis for their ability to reduce HAP formation in the absorption process and to control HAP emissions at the CO_2 absorber column exhaust stacks. Potentially available controls included:

- Process and Design Modifications
  - Absorber Intermediate Cooling
  - Materials of Construction
- Post-Absorber Column Controls
  - Thermal and Catalytic Oxidation
  - Water Wash
    - Acid Wash

Each control option was evaluated for technical feasibility, effectiveness, and applicability to the carbon absorber column. The MACT Analysis included an assessment of the formation mechanisms for both amine and aldehyde HAPs, as well as the technical feasibility and effectiveness of post-absorber controls with respect to both amine and aldehyde HAP emissions. The MACT Analysis concluded that process design upgrades, including absorber column intermediate cooling systems, upgraded materials of construction, and pre-absorber column pollution control systems, would reduce the formation of both amine and aldehyde HAPs.

Process Controls and Design Upgrades. As described in Section 7.2.1 of the MACT Analysis, the solvent used for CO_2 capture is separated from the CO_2-rich solvent in the stripper column and recycled for reuse in the capture process. Emissions from the absorber column generally consist of liquid entrainment (*i.e.,* solvent carryover), aerosol/mist emissions, and gas-phase or vapor solvent degradation byproducts. The amine solvent used to absorb CO_2 from the flue gas is susceptible to degradation due to heat (thermal degradation) and the presence of oxygen (oxidative degradation). Thermal and oxidative degradation of the solvent can lead to the formation of both amine and aldehyde HAPs; thus, process controls or design modifications that reduce degradation will reduce the formation of both amine and aldehyde HAPs.

Oxidative degradation of the solvent occurs due to the presence of oxygen and metal ions, primarily iron in the flue gas. The highest oxygen concentration will occur in the absorber column which is the most likely place for oxidative degradation of the amine. Degradation products include fragments of the amine, such as ammonia and the formation of byproducts such as acetaldehyde, formaldehyde, and ammonia.[11] Oxidative degradation mainly depends on the metal ion

[11] Shao, Renjie and Strangeland, Aage; Amines Used in CO2 Capture – Health and Environmental Impacts, The Bellona Foundation, September 2009, available at: https://network.bellona.org/content/uploads/sites/3/fil_Bellona_report_September_2009_-_Amines_used_in_CO2_capture.pdf, accessed November 1, 2023.

concentration and oxygen concentration in the absorber column. Metal ions, especially iron (Fe), is an important catalyst in oxidation of amines. Metal ions will generate oxide radical which will increase the oxidation rate of amines. Reducing metal ion concentrations in the absorber column will limit the oxidative degeneration and the formation of both amine and aldehyde HAPs.

Thermal degradation may occur in the absorber column and stripper column and is generally dependent upon process operating temperatures. High temperatures will break the chemical bonds of amines and increase the reaction rate of amines reacting with CO_2 to form the thermal degradation byproducts, which will also cause loss of amines in the system. Studies indicate that thermal degradation primarily takes place during the solvent regeneration process in the stripper column, at elevated temperatures and in the presence of CO_2;[12] however, thermal degradation may occur in the absorber column at elevated temperatures. Products of the thermal degradation process are often more volatile than amine solvent and are likely to evaporate in the absorber, resulting in increased emissions.[13] Designing the absorber column with intermediate cooling systems to reduce temperatures within the column will reduce thermal oxidation and the formation of both amine and aldehyde HAPs.

As described in Section 7.2.1 of the MACT Analysis, process controls and design changes incorporated into the design of the DCC Facility, including absorber column intermediate cooling and upgraded materials of construction to eliminate introducing Fe into the absorber, are expected to reduce solvent degradation and the formation of both amine and aldehyde HAPs. Based on information provided by the carbon capture system vendor, design changes implemented to reduce both thermal and oxidative degradation of the solvent will reduce HAP formation by approximately 40% percent from pre-design change levels.

Post-Absorber Column Controls. Post-absorber column control systems were evaluated for the control of both amine and aldehyde HAPs (MACT Analysis, Sections 7.2.3 and 7.2.4). Based on an assessment of technical feasibility and applicability to the absorber column exhaust, it was determined that water wash and acid wash were the only technically feasible post-absorber column control systems. As EPA Region 8 noted, the amine- and aldehyde-based HAP emissions will react differently in the post-absorber column control systems. However, the water wash and acid wash systems are generally designed to address amine carryover from the absorber column and reduce aerosol amine and amine droplets that can result in VOC emissions. The systems also play an important role in curtailing amine losses and maintaining the water balance of the solvent in the absorber column.

Although aldehydes are water soluble, they do not dissociate in water and may not be effectively controlled using a water wash system. In addition, aldehydes are weak acids as the hydrogen atom in the carbonyl group of an aldehyde molecule provide H^+ ions; thus, the acid wash system is not expected to provide effective aldehyde-based HAP emission control. No emissions

---

[12] Buvik, V, Hoisaeter, K, Vevelstad, S., Knuutila, H., A Review of Degradation and Emissions in Post-Combustion CO_2 Capture Pilot Plants, International Journal of Greenhouse Gas Control, February 18, 2021, pg. 2.
[13] *Id.*

data were identified from the carbon capture system vendor or technical literature demonstrating effective aldehyde control using either water wash or acid wash systems. Therefore, no aldehyde-based HAP control was assumed with these systems. These systems are instead designed for reduction of amines.

Projected HAP Emissions and Exhaust Gas Concentration. Based on vendor emission estimates, HAP emissions from the CO_2 absorber column are summarized in the following table. HAP emissions were provided by the carbon capture system vendor, taking into account reduced HAP formation with the intermediate cooling and upgraded materials of construction. Emission estimates assumed no additional control in the water/acid wash systems, other than reducing amine solvent carryover and reducing VOC emissions.

Projected Project-Related §112 Potential-to-Emit HAP Emissions

Hazardous Air Pollutant	**Projected Emission Rate[14]* (lb/hr)**	**Concentration ppbvd @ 15% O_2**
Clean Air Act §112 Listed HAPs		
Acetaldehyde	7.5	464
Formaldehyde	0.4	36
Acetamide	0.12	5.5
Ethylenimine	0.0041	0.3
N-nitrosodiethylamine	0.005	0.1
Nitrosodimethylamine	0.010	0.4
N'-Nitrosomorpholine	0.004	0.09
Total § 112 Listed HAPs	8.04	NA

The feasibility of testing for amine-based HAPs must also be considered. Given the low concentration of amine-based HAPs in the exhaust gas, stack testing would not be feasible. EPA Test Method 320 (Vapor Phase Organic and Inorganic Emissions by Extractive FTIR) would be used to measure both aldehyde and amine-based organic HAP emissions. Test Method 320 specifies a number of analytical uncertainty parameters that the analyst must calculate to characterize the FTIR system performance; however, it does not provide analytical detection limits for all organic compounds. Based on published information it appears that the test method by itself may achieve a minimum detection limit of approximately 100 ppb, and an optimal minimum detection limit as low as 10 ppb for formaldehyde in a natural gas fired turbine field test using optimized hardware and software.[15] No specific information was identified regarding method

[14] Projected lb/hr emission rates are estimated for each HAP based on emissions data and modeling conducted by the control system vendor, and represent worst-case conditions for each individual constituent, which could not occur simultaneously for all constituents.

[15] See, Montrose Environmental, Enhanced Measurements of Low-Concentration Emissions from Combustion Units, available at: https://montrose-env.com/wp-content/uploads/2017/09/CIBO-Low-Level-Emissions-Technologies-Updated.pdf, accessed November 2, 2023; Clean Air, An Alternative Option in EtO Testing, June 18, 2020, available at: https://www.cleanair.com/alternative-option-in-eto-testing/, accessed November 1, 2023.

detection limits for amine-based organic constituents using Test Method 320; however, it appears likely based on optimal minimum detection limit reported for formaldehyde emissions, that the amine concentrations in the exhaust gas (all less than 0.5 ppb) will be well below the minimum detection limit.

Conclusion. Aldehyde HAPs are expected to account for more than 98 percent of all HAP emissions from the absorber column, with acetaldehyde being the individual HAP emitted at the highest rate. Acetaldehyde is proposed as a surrogate for all HAP emissions because (1) acetaldehyde accounts for approximately 93 percent of all HAP emissions; and (2) the design and process changes proposed to reduce thermal and oxidative degradation of the amine solvent will reduce the formation of both amine and aldehyde HAPs.

Sincerely,

DCC East Project LLC

Robert N. McLennan
President and CEO

A.5.ii – DCC East Project LLC Supplemental Response to Comments

5301 32nd Ave. South
Grand Forks, ND 58201
Phone 701.795.4000

DCC EAST PROJECT LLC

December 26, 2023

Jim Semerad, Director, Division of Air Quality
David Stroh, Environmental Engineer
North Dakota Department of Environmental Quality
4201 Normandy Street, 2nd Floor
Bismarck, ND 58503-1324

Re: Supplemental Response for Application of DCC East Project LLC for Permit to Construct No. ACP-18194 for Dakota Carbon Center CO_2 Separation and Purification Plant

Dear Mr. Semerad and Mr. Stroh:

Please accept this letter as a further supplement to the record for the application of DCC East Project LLC (DCC East) for Permit to Construct No. ACP-18194 for the Dakota Carbon Center CO_2 Separation and Purification Plant (the DCC Facility) in Oliver County, North Dakota. This letter offers additional information concerning NDDEQ's determination in the draft Air Permit to Construct that acetaldehyde would be tested as a surrogate for validation of the Section 112 HAPs emissions.

DCC East provides the enclosed report authored by third-party consultant TRC entitled, "Evaluation of the Feasibility of EPA Method 320 to Measure Air Emissions from a Carbon Dioxide Removal System," dated December 15, 2023 (the TRC Report). The TRC Report provides expert analysis of Method 320 as applied to the emissions estimates represented in the application. Consistent with our discussion in our Response Comment dated November 16, 2023, aldehyde HAPs are expected to account for more than 98 percent of all HAP emissions from the absorber column, with acetaldehyde being the individual HAP emitted at the highest rate. The TRC Report further supports acetaldehyde as a surrogate for all HAP emissions because it is the only CAA Section 112 HAP emitted in a greater than 1.0 part per million quantity that is measurable by EPA Method 320. The Report provides discussion of the remaining estimated HAPs, identifying whether they are not detectable (1) due to the lack the availability of a reference standard in the spectral library for the HAPor (2) due to a concentration value below the FTIR spectrometer lowest detection limits, thereby resulting in no quantity value being detected.

DCC East continues to support the use of acetaldehyde as a surrogate for validation of the Section 112 HAPs emissions. While DCC East does not believe that additional verification testing is necessary for the Permit to Construct, formaldehyde could be tested using Method 320. It is the second highest estimated Section 112 HAP emissions value, albeit infinitesimal at 0.4 lb/hr.

Formaldehyde, at its estimated emissions value, is projected to be unmeasurable. For this reason, adding formaldehyde would be a conservative measure to validate emissions estimates.

Thank you for your consideration of this additional information in the permit record.

Sincerely,

DCC East Project LLC

Robert N. McLennan
President and CEO

FINAL REPORT

Evaluation of the Feasibility of EPA Method 320 to Measure Air Emissions from a Carbon Dioxide Removal System

Performed For

DCC East Project LLC

Draft Report No.

TRC Environmental Corporation Report 581624

Report Submittal Date

12/15/23

TRC Environmental Corporation
1429 Rock Quarry Road, Suite 116
Raleigh, North Carolina 27610
USA

T (919) 828-3150
F (919) 838-9661

1429 Rock Quarry Road, Suite 116
Raleigh, North Carolina 27610
T (919) 828-3150
F (919) 838-9661
TRCcompanies.com

Introduction

The Project Sponsors of DCC East Project LLC are developing Project Tundra, the goal of which is to produce CO_2 from the flue gas emissions from the Milton R. Young Station in Center, North Dakota and inject the captured gases into permeable bedrock thousands of feet below the facility(“Project”). A key component of the Project is the Carbon Capture system. CO_2 produced by the capture system is injected into bedrock as described above, and the remaining gases from the flue gas emissions and the capture facility absorber are exhausted to the atmosphere. The North Dakota Department of Environmental Quality (DEQ) has proposed measurement of the CO_2 production facility emissions at the outlet of the absorber using EPA Method 320 (extractive Fourier Transform Infrared (FTIR) spectroscopy).

The Project Sponsors retained Thomas A. Dunder, Ph.D. from TRC to evaluate the feasibility of measuring these emissions with FTIR technology. Dr. Dunder has over 30 years of experience conducting air emissions measurements by FTIR and has detailed knowledge of the technology and its capabilities.

This report summarizes data provided by the CO_2 capture technology vendor (expected emissions, effluent conditions) (“Vendor”) and details the conversion from lb/hr emission rates quoted by the vendor to parts per million concentrations necessary to determine the applicability of FTIR measurements in terms of detection limits.

Results Summary

The table below summarizes the results of the calculations. Detailed explanations and sample calculations of the data conversions and interpretation and provided in the succeeding sections.

1429 Rock Quarry Road, Suite 116
Raleigh, North Carolina 27610
T (919) 828-3150
F (919) 838-9661
TRCcompanies.com

Compound	Emission Rate	Reference Spectrum	MW	SCFM	DSCFM	ppmvd	Measureable
HAPS	lb/hr	Available?	g/mol	Standard ft^3/min	Dry Standard ft^3/min	parts per million, dry basis	By M320
Acetaldehyde	**7.5**	**Y**	**44.053**	**1266249.6**	**1178878.4**	**0.93**	**Y**
Formaldehyde	**0.4**	**Y**	**30.026**	**1266249.6**	**1178878.4**	**0.073**	**N**
Acetamide	0.12	N	59.07	1266249.6	1178878.4	0.011	N
Ethyleneimine	0.0041	N	43	1266249.6	1178878.4	0.00052	N
N-nitrosodiethylamine	**0.0**	**Y**	**102.14**	**1266249.6**	**1178878.4**	**0.00027**	**N**
Nitrosodimethylamine	**0.0**	**Y**	**74.082**	**1266249.6**	**1178878.4**	**0.00074**	**N**
N'-Nitrosomorpholine	**0.0**	**Y**	**116.12**	**1266249.6**	**1178878.4**	**0.00019**	**N**
Other HAPS							
Ammonia	**2.9**	**Y**	**17.031**	**1266249.6**	**1178878.4**	**0.93**	**Y**
Diethylamine	**2.0**	**Y**	**73.14**	**1266249.6**	**1178878.4**	**0.15**	**N**
Ethanolamine	**1.1**	**Y**	**61.08**	**1266249.6**	**1178878.4**	**0.098**	**N**
Ethylamine	**0.8**	**Y**	**45.08**	**1266249.6**	**1178878.4**	**0.093**	**N**
Ethylenediamine	0.25	N	60.1	1266249.6	1178878.4	0.023	N
Formamide	1.2	N	45.04	1266249.6	1178878.4	0.15	N
Methylamine	**0.5**	**Y**	**31.1**	**1266249.6**	**1178878.4**	**0.088**	**N**
Morpholine	0.25	N	87.1	1266249.6	1178878.4	0.016	N

The Vendor provided the first 2 columns of data (compounds and lb/hr estimated emissions) as well as gaseous effluent conditions (temperature, pressure, flow, moisture). For a compound to be measured by Method 320, a set of quantitative reference spectra must be available to identify and determine concentrations. TRC uses the MKS 2030 FTIR instrument that has a spectral library provided with the instrument. TRC determined if each compound was present in the library. The table lines in **BLUE** show compounds for which reference standards are available. Therefore Method 320 can only be used to measure this subset of compounds.

The Vendor provided flow rate in ACFM (actual cubic feet per minute) and this must be converted to DSCFM (dry standard cubic feet per minute) to obtain concentrations in ppmvd (parts per million by volume, dry basis). The FTIR detection limits for different compounds varies depending on the compound (how efficiently it absorbs infrared light) and the presence of interferents whose spectral absorbance overlaps the compound. For a modern FTIR spectrometer equipped with a high sensitivity detector and long pathlength gas cell such as the MKS 2030 instrument, the lowest detection limits are generally in the 0.5-1 ppm range. Reviewing the calculated ppmvd concentrations in the table, some concentrations are in the ppt (parts per trillion) range, and many are in the ppb (parts per billion range). These ppb and ppt concentrations cannot be detected by the MKS FTIR.

1429 Rock Quarry Road, Suite 116
Raleigh, North Carolina 27610
T (919) 828-3150
F (919) 838-9661
TRCcompanies.com

Only 2 compounds from the Vendor estimates, acetaldehyde and ammonia, would be above detection limits based on these calculations. TRC has measured these compounds in many emissions tests and can confirm that they are readily detectable at these concentrations.

Detailed Calculations

The Vendor provided the data in the two tables below.

Compounds and Estimated Emissions

Compound	Emission Rate
HAPS	lb/hr
Acetaldehyde	7.5
Formaldehyde	0.4
Acetamide	0.12
Ethyleneimine	0.0041
N-nitrosodiethylamine	0.005
Nitrosodimethylamine	0.01
N'-Nitrosomorpholine	0.0041
Other HAPS	
Ammonia	2.9
Diethylamine	2
Ethanolamine	1.1
Ethylamine	0.77
Ethylenediamine	0.25
Formamide	1.2
Methylamine	0.5
Morpholine	0.25

1429 Rock Quarry Road, Suite 116
Raleigh, North Carolina 27610
T (919) 828-3150
F (919) 838-9661
TRCcompanies.com

Process Data

Process Data	
Flow	1342800 ACFM
T	99.9 ^{o}F
% H_2O	6.9
% O_2	7.7
P (static)	29.92 " Hg

The flow in ACFM must be first converted to SCFM (actual basis to standard basis) using the following equation:

$$Qscfm = \frac{Qacfm \times (459.67\ ^{o}R\ + 68\ ^{o}F) \times P_o}{(459.67\ ^{o}R + T_o) \times P_s}$$

Where:
Qscfm = gas flow rate at standard temperature and pressure
Qacfm = gas flow rate at actual temperature and pressure (1342800 ft^3/min)
P_o = pressure at actual conditions (inches Hg) (29.92 "Hg)
T_o = temperature at actual conditions (^{o}F) (99.9 ^{o}F)
P_s = pressure at standard conditions (29.92 "Hg)
^{o}R = temperature on Rankine scale

The SCFM flow is converted to dry basis DSCFM using the equation below:

$$Qdscfm = Qscfm \times (1 - \%\ Moisture)$$

Where:
Qscfm = gas flow rate at standard temperature and pressure (Calculated above)
Qdscfm = gas flow rate at standard temperature and pressure, dry basis
% Moisture = Moisture at actual conditions (6.9%)

The final calculation step is to convert the lb/hr emissions to parts per million, dry basis using the data in the summary table presented on page 2. The equation is shown below:

$$Emission\ Rate\ \left(\frac{lb}{hr}\right) = Concentration(ppmvd) \times Molecular\ Weight\left(\frac{g}{mole}\right) \times Flow\ Rate\ (dscfm) \times 60\ min/hr \times \frac{1}{3.853x10^{8}}$$

1429 Rock Quarry Road, Suite 116
Raleigh, North Carolina 27610
T (919) 828-3150
F (919) 838-9661
TRCcompanies.com

Respectfully submitted,

TRC Environmental Corporation

Thomas Dunder, Ph.D.
Technical Director

A.6 – Department Response to Public Comments

Response to Comments Received
by
The North Dakota Department of Environmental Quality
on
Draft Air Pollution Permit to Construct No. ACP-18197 v1.0
DCC East Project LLC - Dakota Carbon Center CO2 Separation and Purification Plant
Oliver County, North Dakota

December 2023

A public comment period was held regarding the above draft Air Pollution Control Permit to Construct (PTC) from September 21, 2023, through October 21, 2023. The comments received by the North Dakota Department of Environmental Quality (NDDEQ) and the response to each comment by NDDEQ is shown below.

Comments were received from three parties which consisted of two individual commentors and Region 8 of the Environmental Protection Agency (EPA R8). The two individual comments provided verbal testimony during the public hearing held on October 19, 2023, in Center, North Dakota. EPA Region 8 submitted written comments to NDDEQ staff on October 20, 2023.

Note on EPA Comment Submittal:
NDDEQ acknowledges EPA's comments on the draft PTC and will introduce them into the record despite EPA R8 not following NDDEQ's stated requirements. When commenting on future actions proposed by the NDDEQ, please read the notice of intent (NOI) and follow the instructions provided within, see Appendix A.1.

As stated in the NOI *"Direct comments in writing, including **Re: Public Comment Permit Number ACP-18194 v1.0**, to* **AirQuality@nd.gov** *or the NDDEQ, Division of Air Quality, 4201 Normandy Street, 2nd Floor, Bismarck, ND 58503-1324.* ***Emailed comments must be sent to the email address above to be considered****." **(emphasis added)***.

NDDEQ makes this clear statement in the NOI to help mitigate the potential for staff to miss comments received in their personal email inbox which are required to be introduced into the record. Further, emailing comments directly to staff is unreliable since staff turnover can happen rapidly.

Verbal Comment No. 1:

Both individual commentors who provided verbal testimony on October 19, 2023, expressed strong support for the Project. The commentors indicated how important the Project was for the area, for North Dakota, and for decarbonization goals. The complete transcript of the hearing can be found in Appendix A.4.

Response to Verbal Comment No. 1:

Thank you for the comments and overall support for the proposed Project. NDDEQ generally agrees with the statements raised. The concerns expressed are outside the scope of the PTC, however, these concerns are important items for North Dakota.

Written Comment No. 1:

EPA R8 comments on the potential for source aggregation between DCC East Project LLC's proposed Dakota Carbon Center CO_2 Separation and Purification Plant (DCC) and Minnkota's Milton R, Young Station (MRY). EPA recommended NDDEQ enhance the permit record to support NDDEQ's source aggregation conclusion and better outline the relationship between the entities.

Embedded within this comment is a notion that if DCC and MRY are determined to be part of the same "stationary source", it will dictate whether the project requires a Permit to Construct a minor or major new source or a minor or major "modification" to an existing source.

Response to Written Comment No. 1:

NDDEQ agrees with EPA R8 that the permit record regarding the relationship and source aggregation conclusion could be enhanced. To address this comment, DCC has better documented the nature of the relationship between DCC and MRY. This information is provided in Appendix A.5.i, pages 1-5.

NDDEQ affirms that DCC's supplemental information adequately explains the nature of the relationship between DCC and MRY and supports the determination that the sources should not be aggregated. As a result of introducing this information into the permit record, no changes to the Permit to Construct are necessary.

Regarding the embedded comment that, if DCC and MRY are considered the same "stationary source" then a minor or major "modification" to an existing source should be evaluated, NDDEQ notes that the potential to emit for DCC is below the significant emissions increase[1,2] thresholds for regulated NSR pollutants[3] that triggers the major modification[4] for existing major stationary sources. In other words, regardless of source aggregation (one source or two), DCC would be considered a "PSD minor source" – as currently proposed, or DCC would be a minor "modification" to an existing major source – if aggregated with MRY. No further modification to the Permit to Construct or Air Quality Effects Analysis is warranted.

Written Comment No. 2:

[1] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(40)
[2] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(23)(i)
[3] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(50)
[4] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(2)(i)

EPA R8 comments on the level of incorporation by reference in the proposed Permit to Construct. EPA recommended NDDEQ revise the permit to include more detailed incorporation by reference.

Response to Written Comment 2:
NDDEQ agrees that the permit record could be enhanced and will add the rated horsepower for the emergency diesel fire pump engine (EU D03) to the emission unit description in the final Permit to Construct (see table under Condition I.B.4 of ACP-18194 v1.0) and final Air Quality Effects Analysis (see page 8 of ACP-18194 v1.0 AQEA).

As proposed, Condition II.C.1 and Condition II.D.1 of ACP-18194 v1.0 both state the emission unit, emergency diesel fire pump engine EU D03, at the proposed facility specifically subject to 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ, respectively.

Condition II.C.1 "*40 CFR 60,* ***Subpart IIII*** *– Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* ***(EU D03)****.*" (**emphasis added**).

Condition II.D.1 "*40 CFR 63,* ***Subpart ZZZZ*** *– National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* ***(EU D03)****.*" (**emphasis added**).

NDDEQ's experience as the Clean Air Act implementation and enforcement authority has shown that the level of incorporation by reference as written in the Permit to Construct requirements for 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ including emission unit identification has been sufficient and useful to the applicant and public to determine what standard applies to the emission unit and how the source is to achieve compliance with each standard. NDDEQ will consider specifying which portions of the above-mentioned regulations apply in the future Title V permit to operate.

Written Comment No. 3:
EPA R8 comments on the ambient air boundary used for the air dispersion modeling for the proposed DCC project with relation to MRY. EPA recommended NDDEQ confirm the accuracy of the ambient air boundary and associated receptor grid used for the air dispersion modeling.

Response to Written Comment 3:
NDDEQ has confirmed the accuracy of the ambient air boundary and associated receptor grid used for the air dispersion modeling. To address this comment, DCC has better outlined the site access and security requirements, the lessor/lessee relationship, and reference to contractual agreements which transfers the "pass through[5]" flue gas back to MRY. This information is provided in detail in Appendix A.5.i, pages 5 and 6.

---

[5] DCC's objective is to remove the carbon dioxide from the MRY flue gas stream. The remaining species (e.g., nitrogen oxides, sulfur oxides, particulate matter, uncaptured carbon dioxide) are transferred back to MRY at the absorber stack discharge.

NDDEQ concurs with the information provided by DCC. Therefore, the ambient air boundary and associated receptor grid are accurate and no further air dispersion modeling is warranted.

Written Comment No. 4:
EPA R8 comments on the Clean Air Act 112(g) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs), particularly regarding the use of acetaldehyde as a surrogate pollutant for all organic HAPs. EPA recommended NDDEQ separately evaluate the effectiveness of controls for amine HAPs from aldehyde HAPs.

Response to Written Comment 4:
DCC's Permit to Construct application included a detailed analysis of potentially available controls to reduce VOC and organic HAP emissions from the CO_2 absorber.[6] The analysis was inclusive of organic HAP emissions and noted that aldehydes make up the majority of the HAP emissions and the remaining HAP constituents are generally classified as amines. Of note, the total of all the expected Clean Air Act Section 112 amine HAPs is approximately 0.10 tons per year (tpy), or significantly below HAP major source thresholds for any individual HAP.[7] As explained in the case-by-case MACT, amine HAPs are reduced using water wash and acid wash to limit the amine solvent loss. Aldehyde HAPs are not expected to be affected by the water and acid wash. The analysis also recognized that aldehydes and amines are generally classified as VOCs and the available controls were evaluated for effectiveness included technologies in industry to reduce VOC emissions.[8] The NDDEQ found no deficiency in the case-by-case MACT analysis.

DCC has also provided a more succinct response, largely based on information already in the record[9], to help EPA R8 understand the aldehyde/amine relationship as it relates to DCC. This can be found in Appendix A.5.i, pages 6-10.

As part DCC's response to EPA R8's comment, DCC discussed the lack of feasibility for testing[10] amine-based HAPs due to the projected low concentrations of these species and limited published information on detection limits for amine-based organic compounds. DCC provided additional technical information on the feasibility of HAP testing using Method 320 in a supplemental response to comment, included in Appendix A.5.ii. DCC indicated that any amine-based organic HAPs would be well below the minimum detection limit of Method 320 or do not have reference spectra. NDDEQ does not possess any technical information to dispute this claim and will not require DCC to test for amine-based organic HAPs.

---

[6] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix C. June 2, 2023
[7] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix B, page 2. June 2, 2023
[8] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix C, page 9. June 2, 2023
[9] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix C.
[10] Using EPA Test Method 320 – Vapor Phase Organic and Inorganic Emissions by Extractive FTIR

Since DCC project is the first of its kind and size in the world[11], NDDEQ's position is that initial testing of the second largest projected Section 112 HAP species (formaldehyde) is reasonable and will be required. NDDEQ does not dispute the projected project related HAP emission determined from emissions testing and modeling conducted by the carbon capture system vendor but is of the opinion that evaluation of formaldehyde in addition to acetaldehyde is warranted for the initial testing required after DCC project start-up.

NDDEQ's conclusion as it relates to HAP testing is that initial testing will be required to confirm the HAP representations made in the permit application for acetaldehyde as a suitable surrogate and has added emissions testing in the final Permit to Construct (See Condition II.F of ACP-18194 v1.0) and final Air Quality Effects Analysis (see page 12 and 13 in ACP-18194 v1.0 AQEA). NDDEQ is requiring EPA Method 320 – Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy as the means to confirm the representations made in the Permit to Construct application. Undetectable organic compounds (i.e., below detection limit) will be considered insignificant.

[11] Given that this is the first of its kind in scale carbon capture project on lignite coal-fired electrical generating utilities and has yet to be constructed, carbon capture and sequestration/storage (CCS) has not yet been "adequately demonstrated" in practice to be identified as a "best system of emissions reduction".

AIR QUALITY IMPACT ANALYSIS

DCC East Project LLC
CO_2 Separation and Purification Plant

Prepared By:

TRINITY CONSULTANTS
3601 Green Road
Suite 102
Beachwood, OH 44122
(216) 278-0500

September 15, 2023

Project 232401.0032

Approved By:

North Dakota Department of Environmental Quality
Division of Air Quality
Air Pollution Control Program

David Stroh, Environmental Engineer

Rhannon Thorton, Environmental Scientist

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. EXECUTIVE SUMMARY

DCC East Project LLC (DCC) completed air dispersion modeling to demonstrate compliance with the North Dakota Ambient Air Quality Standards (ND AAQS) for a proposed project to construct a carbon dioxide (CO_2) separation and purification plant (Project) to generate commodity CO_2 from the flue gas produced by the Milton R. Young (MRY) Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2). The modeling was completed using potential emissions from the project under two operating scenarios. Based on the data provided in the Permit to Construct (PTC) application and Trinity Consultants' (Trinity's) independent review and modeling analysis, it is expected that the proposed project will comply with applicable ND AAQS. Results for the modeled ND AAQS analysis are shown in Table 1-1.

Table 1-1. ND AAQS Analysis Results Summary

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	ND AAQS ($\mu g/m^3$)
NO_2	1-hr[1]	44.20	35.0	79.20	188
	Annual[2]	1.33	5.0	6.33	100
PM_{10}	24-hr[3]	7.97	30.0	37.97	150
$PM_{2.5}$	24-hr[4]	5.56	13.7	19.26	35
	Annual[5]	0.71	4.8	5.46	12
SO_2	1-hr[6]	48.33	13.0	61.33	196
	3-hr[7]	60.70	11.0	71.70	1,309
	24-hr[7]	16.16	9.0	25.16	365
	Annual[2]	1.54	3.0	4.54	80
CO	1-hr[7]	32.24	1,149.0	1,181.24	40,000
	8-hr[7]	10.98	1,149.0	1,159.98	10,000

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eighth-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

2. INTRODUCTION AND BACKGROUND

In June 2023, DCC submitted a revised PTC application to the North Dakota Department of Environmental Quality, Division of Air Quality (Department) to construct the Project. A revised air dispersion modeling protocol and modeling report that reflects the information in this PTC application was submitted by DCC in August 2023. The revised modeling report summarizes the ND AAQS modeling analysis that was completed, using AERMOD v22112 for the Project. The analysis demonstrates compliance with the ND AAQS. Trinity was contracted to assist the Department with a third-party review of the modeling analysis and preparation of an Air Quality Impact Analysis (AQIA) report. This AQIA summarizes Trinity's findings based on a thorough review and independent modeling of the Project.

DCC is proposing to construct a CO_2 separation and purification plant to generate commodity CO_2 from the flue gas produced by the MRY Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2). The carbon capture system includes a new CO_2 absorber stack where processed flue gas from MRY Units 1 and 2 will be emitted. The Project will receive commingled flue gases from MRY Units 1 and 2, which will be processed to remove CO_2, and the uncaptured emissions (e.g., nitrogen oxides) will be emitted through the Project's CO_2 absorber stack (emission unit and emission point D01 in ACP-18194 v1.0). Capability to exhaust all or a portion of the exhaust from MRY Units 1 and 2 through the existing stacks for MRY Units 1 and 2 will be retained. The Project will consist of installation of the following emission sources:

- One (1) carbon capture system,
- One (1) cooling tower,
- One (1) emergency diesel-fired fire water pump engine,
- Amine solvent storage tanks and handling system, and
- Haul roads.

3. MODEL REQUIREMENTS

The Project's potential to emit (PTE) for the regulated New Source Review (NSR) pollutants are below major source thresholds. Therefore, the project will not trigger Prevention of Significant Deterioration (PSD) permitting and does not explicitly require modeling per the Department's non-PSD project modeling policy.[1] However, because the carbon capture stack will have considerably different stack characteristics (e.g., shorter stack) than the existing MRY Unit 1 and MRY Unit 2 stacks; the Department required that DCC complete a modeling assessment for this project to demonstrate compliance with the ND AAQS for operating scenarios when emissions are exhausted through the new carbon capture system stack.

Per Department guidance, modeling for PTC applications not subject to PSD are only required to address compliance with the ND AAQS. Therefore, the DCC modeling analysis did not include a modeling assessment against the PSD increment standards. Additionally, the MRY facility is not located within 50 km of any Class I area; therefore, in accordance with Department guidance a Class I increment assessment is not required for the Project.

Emissions from the carbon capture system stack and the cooling towers were included in the ND AAQS modeling analysis. The diesel fire water pump engine was not included in accordance with the Department's policy.[2] The haul roads associated with the project were not included in modeling because they are paved and Department convention is to exclude paved haul roads from ND AAQS modeling. Finally, the amine solvent storage tanks and handling system has only insignificant emissions of VOCs that need not be included in the ND AAQS modeling analysis.

[1] https://deq.nd.gov/publications/aq/Policy/modeling/Criteria_Modeling_Memo.pdf

[2] https://deq.nd.gov/publications/AQ/policy/Modeling/Emergency_Unit_Modeling.pdf

4.1 Model Version

The current U.S. EPA regulatory model, AERMOD (version 22112) was used in this analysis to calculate ground-level concentrations with the regulatory default parameters. Appropriate averaging periods, based on federal and state ambient air quality standards, and model options were considered in the analysis, in conjunction with the U.S. EPA's *Guideline on Air Quality Models* 40 CFR 51, Appendix W (Revised, January 17, 2017).

4.2 Meteorological Data

Surface and upper-air data are pre-processed by AERMET to generate the boundary layer parameters required by AERMOD to calculate plume dispersion. AERMET processes hourly meteorological data to determine plume transport and dispersion downwind of a source. Per Appendix W Section 8.4.2.e, a *minimum* of either one year of site-specific data (i.e., an onsite monitor) or five years of representative National Weather Service (NWS) data or at least 3 years of prognostic meteorological data should be used to ensure a sufficiently conservative result which addresses hourly and seasonal variation in meteorological conditions over a year which affect plume movement due to atmospheric conditions.

Hourly meteorological data for the 5-year period of 2017 to 2021 were used from a state-operated meteorological observation station in Beulah, ND. Data from this site were supplemented with concurrent cloud cover and upper air observations from the Bismarck Airport in Bismarck, ND. Missing upper air data from Bismarck were substituted with data from Glasgow, MT and Aberdeen, SD.[3]

See Table 4-1 for MET stations used. AERMET uses hourly surface observations of wind speed and direction, ambient temperature, sky cover (opacity), and (optionally) local air pressure. AERMET then includes the pre-processed AERSURFACE output values (see Table 4-2) to compile the appropriate surface meteorological inputs for AERMOD. AERMET version 22112 was used to process meteorological data for this analysis.

Surface roughness length, albedo, and Bowen ratio are required values used by AERMET to preprocess meteorological data for AERMOD. AERSURFACE allows users to develop these values using inputs based on set seasonal variability in the vegetative landscape (e.g. landcover). The Department has compiled a set of recommended inputs to be used for the AERSURFACE pre-processor for various regions of the state as listed in the *Recommended AERSURFACE Inputs (North Dakota)* guidance as shown in Table 4-2.[4] Seasonal category assignments for each month were based on recommendations for the southwest geographic area. Four sectors were used in the analysis to define surface roughness length, as shown in Figure 4-1. AERSURFACE version 20060 was used for this analysis with land cover, impervious surface, and tree canopy data from the USGS National Land Cover Data (NLCD) archives for 2016.

[3] A total of 22 days over the 5 years to be modeled were substituted.

[4] https://deq.nd.gov/publications/AQ/policy/Modeling/AERSURFACE_InputsND.pdf

Table 4-1. Meteorological Data Stations

Location	Latitude (deg)	Longitude (deg)	Base Elevation (m)	Distance / Direction from Source*	Data Type
Beulah, ND	47.229	-101.767	630	45 km W-NW	Surface
Bismarck Airport - Bismarck, ND	46.774	-100.748	506	48 km SE	Surface
Bismarck, ND	46.774	-100.748	503	48 km SE	Upper Air
Glasgow, MT	48.200	-106.620	693	430 km W-NW	Upper Air
Aberdeen, SD	45.455	-98.420	397	280 km SE	Upper Air

* Approximate distances using Google Earth's measuring tool.

Table 4-2. AERSURFACE Input Values

Parameter	Value Used
Radius of study area used for surface roughness.	1 km
Define the surface roughness length for multiple sectors?	Yes
Temporal resolution of surface characteristics	Monthly
Continuous snow cover for at least one month?	Yes
Reassign the months to different seasons?	Yes
Specify months for each season.	
Late autumn after frost and harvest, or winter with no snow.	Oct, Nov, Dec, Feb, Mar
Winter with continuous snow on the ground.	Jan
Transitional spring.	Apr, May
Midsummer with lush vegetation.	Jun, Jul, Aug
Autumn with unharvested cropland.	Sep
Is the site at an airport?	No
Is the site in an arid region?	No
Surface moisture condition at the site.	Average

Figure 4-1. Sectors Used for Surface Roughness Characteristics at Beulah Station

4.3 Receptor Grid

Receptors are the locations where the model calculates ground-level pollutant concentrations. The receptor grid included discrete receptors at specific intervals around the facility extending out in a square shape with the facility at the center.

- Fence line receptors along the secured MRY property boundary with spacing of 25 meters
- 50 meter spacing, extending out approximately 500 meters from the boundary
- 100 meter spacing, extending out approximately 3 kilometers from the boundary
- 250 meter spacing, extending between approximately 3 to 5 kilometers from the boundary
- 500 meter spacing, extending between approximately 5 to 10 kilometers from the boundary

Receptor points within the MRY Station boundary are not modeled as they are not considered ambient air.[5] Ambient air has been interpreted to be air located outside of a boundary (e.g., a fence) which restricts general public access to a facility or source.

4.4 Terrain Elevations

The terrain elevation for each receptor point was determined using USGS 1/3 arc-second National Elevation Dataset (NED) data. The data, obtained from the USGS, has terrain elevations at 10-meter intervals. The terrain height for each individual modeled receptor was determined by assigning the interpolated height from the digital terrain elevations surrounding each modeled receptor.

In addition, the AERMOD terrain processor, AERMAP (version 18081), was used to compute the hill height scales for each receptor. AERMAP searches all NED data points for the terrain height and location that has the greatest influence on each receptor to determine the hill height scale for that receptor. AERMOD then uses the hill height scale in order to select the correct critical dividing streamline and concentration algorithm for each receptor. The elevations of the sources and buildings involved in the modeling demonstration were set using AERMAP.

4.5 NO_2 Modeling Methodology

For nitrogen dioxide (NO_2) modeling, the USEPA approved Tier 3 Plume Volume Molar Ratio Method (PVMRM) was utilized. USEPA Appendix W and subsequent guidance recommends a three tier NO_2 modeling approach for the conversion of nitric oxide (NO) to NO_2. These tiers are regulatory options provided in AERMOD and each consider increasingly complex considerations of NO to NO_2 conversion chemistry.

- Tier 1 assumes total conversion of NO to NO_2;
- Tier 2 utilizes the revised Ambient Ratio Method 2 (ARM2) approach; and,
- Tier 3 incorporates the Ozone Limiting Method (OLM) and Plume Volume Molar Ratio Method (PVMRM) as regulatory options in AERMOD.

Numerous studies and reports that analyze use of PVMRM and OLM show that for a given NO_X emission rate and ambient ozone concentration, the NO_2/NO_X conversion ratio for PVMRM is primarily controlled by the volume of the plume, whereas the conversion ratio for OLM is primarily controlled by ground-level NO_X concentration. EPA memoranda do not indicate any preference between PVMRM and OLM. EPA guidance

[5] https://www.epa.gov/nsr/ambient-air-guidance

suggests that PVMRM is preferred for isolated, elevated point sources.[6] This modeling analysis is specifically examining impacts from three relatively isolated, elevated point sources. As such, PVMRM was selected as the Tier 3 approach to be utilized in the modeling analysis using the ozone data discussed in Section 4.5.1 and NO_2 to NO_X ratios discussed in Section 4.5.2.

4.5.1 Ozone Data

Hourly ozone data from 2017 through 2021 for the Hannover ozone monitor (AQS Site ID: 38-065-0002) was used as the primary ozone data for the Tier 3 PVMRM analysis. Missing Hannover observations were filled using a three-step process:

1) Missing observations were filled with observations from the nearby Beulah North ozone monitor (AQS Site: 38-057-0004).
2) After supplementing Hannover observations with observations from Beulah North, remaining single missing hourly observations were filled using linear interpolation.
3) Data gaps of more than one hour were filled using a table of monthly and diurnal varying maximum hourly observations developed from the combined Hannover/Beulah North dataset.

4.5.2 In-Stack and Ambient Equilibrium Ratios

PVMRM in AERMOD uses an in-stack ratio (ISR) that specifies the ratio of NO_2 /NO_X present in each stack. In lieu of using the default ISR of 0.5, an ISR of 0.1 was used for the absorber stack, MRY Unit 1, and MRY Unit 2. This ISR was justified by the applicant using NO_2 and NO_X emissions data from MRY Unit 1 and MRY Unit 2. An ISR of 0.2 was used for nearby sources based on EPA guidance that indicates this value can be used for nearby sources located greater than 1-3 km away from the source being permitted.[7]

The default ambient equilibrium ratio of 0.9 was used.[8]

4.6 Rural/Urban Option Selection in AERMOD

For any dispersion modeling exercise, the “urban” or “rural” determination of the area surrounding the subject source is important in determining the applicable atmospheric boundary layer characteristics that affect a model’s calculation of ambient concentrations. Thus, a determination was made of whether the area around the MRY Station was urban or rural.

One method discussed in Section 5.1 of the *AERMOD Implementation Guide*[9] (also referring therein to Section 7.2.3c of the Guideline on Air Quality Models, Appendix W) is called the “land use” technique because it examines the various land use within 3 km of a source and quantifies the percentage of area in various land use categories. If greater than 50% of the land use in the prescribed area is considered urban, then the urban option should be used in AERMOD.

There is much less than 50% compact residential and industrial development in the 3-km radius surrounding the MRY Station. Therefore, rural dispersion characterization was used for this modeling effort.

[6] https://www.epa.gov/sites/default/files/2015-07/documents/appwno2_2.pdf

[7] https://www.epa.gov/sites/default/files/2020-10/documents/no2_clarification_memo-20140930.pdf

[8] https://www.epa.gov/sites/default/files/2015-07/documents/appwno2_2.pdf

[9] https://gaftp.epa.gov/Air/aqmg/SCRAM/models/preferred/aermod/aermod_implementation_guide.pdf

4.7 Building Downwash

The purpose of a building downwash analysis is to determine if the plume discharged from a stack will become caught in the turbulent wake of a building (or other structure), resulting in downwash of the plume. The downwash of the plume can result in elevated ground-level concentrations.

The Building Profile Input Program (BPIP) with Plume Rise Model Enhancements (PRIME) (version 04274) was used to determine the building downwash characteristics for each stack in 10-degree directional intervals. The PRIME version of BPIP features enhanced plume dispersion coefficients due to turbulent wake and reduced plume rise caused by a combination of the descending streamlines in the lee of the building and the increased entrainment in the wake. For PRIME downwash analyses, the building downwash data include the following parameters for the dominant building:

- Building height,
- Building width,
- Building length,
- X-dimension building adjustment, and
- Y-dimension building adjustment.

The Good Engineering Practice (GEP) stack height determined using BPIP for the stacks for the absorber stack (ABSORB), cooling tower stacks (CT 1-18), MRY Unit 1 (Unit 1), and MRY Unit 2 (Unit 2) are shown in Table 4-3 compared with the physical stack heights. The preliminary GEP stack height value is greater than the physical stack heights for the absorber and cooling tower stacks; therefore, the full physical stack heights were modeled for these stacks. For the MRY Unit 1 and MRY Unit 2 stacks, the preliminary GEP stack height values are slightly less than the physical stack heights. In the model supporting the PTC application for the Project, the full physical stack height of MRY Unit 1 and MRY Unit 2 was used. A sensitivity analysis for stack height was completed by AECOM, who prepared the modeling, indicating that the percentages of the ND AAQS in the modeled results (rounded to the nearest whole number) are unaffected if the preliminary GEP stack height values were modeled. As shown later, the model results are well less than the ND AAQS; therefore, the conclusions of the modeling report with respect to ND AAQS compliance would be unaffected by modeling a reduced stack height compared with the physical stack height.

Table 4-3. GEP Stack Height Analysis

Stack ID	Physical Stack Height (m)	GEP Equation Height (m)	Preliminary GEP Stack Height Value (m)
ABSORB	102.44	123.60	123.60
CT1-CT4; CT10-CT14	16.76	41.90	65.00
CT5-CT9; CT15-CT18	16.76	72.20	72.20
UNIT1	171.91	170.93	170.93
UNIT2	167.64	164.45	164.45

4.8 Representation of Emission Sources

AERMOD allows for emission units to be represented as point, area, volume, or open pit sources, among other less commonly used source types. A source with a stack is most appropriately modeled as a point source. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in the modeling analyses.

4.8.1 Emission Sources at MRY Station

The modeled sources at the MSY Station include point sources with upward unrestricted releases, which were modeled with the POINT source type. Allowable emission rates were used with other stack parameters for the absorber stack, MRY Unit 1, MRY Unit 2, and the cooling tower for two operating modes. In Mode 1, all of Unit 2's flue gas is treated while only 25% of Unit 1's flue gas is treated. In Mode 2, all of Unit 1's flue gas is treated while only 57% of Unit 2's flue gas is treated. For either Mode 1 or Mode 2 operations, the balance of the untreated plume is assumed to be emitted out its original stack (Mode 1 – 75% of Unit 1 is emitted out the Unit 1 stack; Mode 2 – 43% of Unit 2 is emitted out the Unit 2 stack).

Stack parameters and emission rates for the two operating mode scenarios are shown in Table 4-4.

Table 4-4. Absorber, Cooling Tower, MRY Unit 1, and MRY Unit 2 Emission Rates and Stack Parameters

Mode No.	Source	Stack ID	Unit	% Flue Gas Treated	Stack Ht. (m)	Stack Diam. (m)	Flue Gas Temp (K)	Flue Gas Velocity (m/s)	SO_2 (g/s)	NO_X (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	CO (g/s)
1	All Unit 2, Partial Unit 1	ABSORB	Unit 1 Unit 2	25% 100%	102.13	5.49	310.87	26.81	82.81	314.11	56.47	56.47	26.84
	Remaining Unit 1	UNIT1	Unit 1	75%	171.91	6.20	334.76	11.55	35.44	108.86	19.11	19.11	9.07
2	All Unit 2, Partial Unit 2	ABSORB	Unit 1 Unit 2	100% 57%	102.13	5.49	310.87	26.81	87.72	303.51	54.04	54.04	25.67
	Remaining Unit 2	UNIT2	Unit 2	43%	167.64	9.14	335.76	5.47	30.53	119.46	21.54	21.54	10.24
	Cooling Tower	CT1-CT18	CT1-CT18[1]	N/A	16.76	9.75	310.04	11.46	N/A	N/A	6.43E-03	4.88E-05	N/A

1 Parameters represent each cooling tower cell exhaust.

4.8.2 Nearby and Other Sources

As described in Section 8.3 of the *Guideline*, background concentrations consist of two categories: 1) nearby sources and 2) other sources. "Nearby sources" are those individual sources located in the vicinity of the sources that are the primary focus on the modeling analysis that are not adequately represented by ambient monitoring data. These sources should be few in number (Appendix W Section 8.3.3(b)(iii)) and are accounted for by explicitly modeling their emissions. "Other sources" are that portion of the background attributable to natural sources, other unidentified sources in the vicinity, and regional transport contributions from more distant sources. Other sources are typically accounted for through use of ambient monitoring data.

Nearby sources explicitly modeled in this analysis include stacks at all three coal-fired electric generating stations located within 50 km of the MRY Station. Point source parameters and emission rates for these sources are shown in Table 4-5.

Table 4-5. Nearby Source Emission Rates and Stack Parameters

Facility	Stack Ht. (m)	Stack Diam. (m)	Flue Gas Temp (K)	Flue Gas Velocity (m/s)	SO_2 (g/s)	NO_X (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	CO (g/s)
Coal Creek	206.41	7.86	334.26	18.59	92.56	103.72	1.25	0.14	6.79
Coal Creek	206.41	7.86	332.04	18.01	89.62	83.11	2.46	0.26	13.17
Coyote	151.79	6.40	378.15	27.86	362.90	181.93	1.13	0.09	17.90
Leland Olds	182.88	5.64	335.37	14.17	17.14	26.71	1.65	0.67	24.15
Leland Olds	182.88	8.23	335.37	9.48	33.81	107.63	1.21	0.49	24.23

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from natural and non-modeled anthropogenic sources. The Department modeling guidance provides fixed background concentrations for criteria pollutants that reflect default values which are representative for the entire State of North Dakota.[10] These values are provided in Table 4-6 and were used in the air quality modeling analysis.

Table 4-6. Background Concentrations (μg/m³)

	Averaging Period				
Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
SO_2	13	11	---	9	3
NO_2	35	---	---	---	5
PM_{10}	---	---	---	30	15
$PM_{2.5}$	---	---	---	13.7	4.75
CO	1,149	---	1,149	---	---

[10] https://deq.nd.gov/publications/AQ/policy/Modeling/ND_Air_Dispersion_Modeling_Guide.pdf

5. NAAQS MODELING ANALYSIS

A ND AAQS analysis was conducted to determine the cumulative impact from the Project, existing MRY sources, nearby sources, and background in the vicinity of the MRY Station. The modeling results in micrograms per cubic meter (μg/m^3) are summarized in Tables 5-1 and 5-2. As shown in the tables, the modeled impacts of the proposed project were below the ND AAQS for each pollutant and averaging period for both operating modes modeled.

Table 5-1. ND AAQS Modeling Results for Mode 1

Pollutant	Averaging Period	Rank of Modeled Impacts	Mode 1 Modeled Conc. (μg/m^3)	Background Conc. (μg/m^3)	Total Conc. (μg/m^3)	ND AAQS (μg/m^3)	% of Criteria
NO_2	1-hr[1]	H8H	43.48	35.0	78.48	188	42
	Annual[2]	H1H	1.31	5.0	6.31	100	6
PM_{10}	24-hr[3]	H6H	7.81	30.0	37.81	150	25
$PM_{2.5}$	24-hr[4]	H8H	5.47	13.7	19.17	35	55
	Annual[5]	H1H	0.71	4.75	5.46	12	45
SO_2	1-hr[6]	H4H	47.25	13.0	60.25	196	31
	3-hr[7]	H2H	60.40	11.0	71.40	1,309	5
	24-hr[7]	H2H	15.20	9.0	24.20	365	7
	Annual[2]	H1H	1.48	3.0	4.48	80	6
CO	1-hr[7]	H2H	31.82	1,149.0	1,180.82	40,000	3
	8-hr[7]	H2H	10.74	1,149.0	1,159.74	10,000	12

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eighth-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

Table 5-2. ND AAQS Modeling Results for Mode 2

Pollutant	Averaging Period	Rank of Modeled Impacts	Mode 2 Modeled Conc. (μg/m^3)	Background Conc. (μg/m^3)	Total Conc. (μg/m^3)	ND AAQS (μg/m^3)	% of Criteria
NO_2	1-hr[1]	H8H	44.20	35.0	79.20	188	42
	Annual[2]	H1H	1.33	5.0	6.33	100	6
PM_{10}	24-hr[3]	H6H	7.97	30.0	37.97	150	25
$PM_{2.5}$	24-hr[4]	H8H	5.56	13.7	19.26	35	55
	Annual[5]	H1H	0.71	4.75	5.46	12	46
SO_2	1-hr[6]	H4H	48.33	13.0	61.33	196	31
	3-hr[7]	H2H	60.70	11.0	71.70	1,309	5
	24-hr[7]	H2H	16.16	9.0	25.16	365	7
	Annual[2]	H1H	1.54	3.0	4.54	80	6
CO	1-hr[7]	H2H	32.24	1,149.0	1,181.24	40,000	3
	8-hr[7]	H2H	10.98	1,149.0	1,159.98	10,000	12

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eighth-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

6. AIR TOXICS ANALYSIS

The Policy for the Control of Hazardous Air Pollutant Emissions in North Dakota (Air Toxics Policy)[11] outlines the methods used to evaluate new or modified emission sources which release Hazardous Air Pollutants (HAPs) into the ambient air for their potential carcinogenic and non-carcinogenic health risks. The acceptable risk is evaluated by determining the maximum individual carcinogenic risk (MICR) for all toxics with known or possible carcinogenic effects. A MICR value of 1.0 x 10-5 (i.e., 1 in 100,000 risk), and Hazard Index (HI) of 1 are the accepted thresholds, any value greater will trigger further review by the Department.

6.1 Method

The Air Toxics Policy outlines a three-tier approach for use in determining compliance. Tier 1 uses lookup tables (provided in pages 16-17 of the Air Toxics Policy), which lists normalized maximum 1-hr concentrations for various stack heights and downwind distances.

Tier 2 involves using EPA's SCREEN3 model to produce the highest predicted 1-hr concentration from a matrix of predictions for a given set of source conditions and downwind distances in all plausible meteorological conditions. The use of SCREEN3 is considered conservative, but less conservative than Tier 1.

Tier 3 involves the use of refined EPA computer models, such as AERMOD. The use of refined modeling uses actual hour-by-hour meteorological and actual site terrain data. The use of refined modeling also treats each stack or emission point independently. DCC implemented a Tier 3 analysis.

The specifics of each Tier's methods for calculating MICR and the Hazard Index can be found in the Air Toxics Policy.

6.2 Air Toxics Results

DCC performed a conservative Tier 3 approach to determine the MICR and HI which would result from the Project. This conservative approach consisted of DCC normalizing total toxic emissions from the absorber stack to 1 g/s. The unit modeled impacts were then scaled based on the emission rates of HAP emitted and divided by the pollutant specific unit risk factor to obtain calculated risk and hazard indices. These results are shown in Table 6-1. The results are well below the thresholds and indicate that the expected MICR and HI concentrations are well in compliance with the Air Toxics Policy. Refer to DCC's permit application for the detailed discussion regarding the Air Toxics analysis and results.

Table 6-1. Air Toxics MICR and Hazard Index Results

Standard	Limit	Results	Pass (Y/N)
MICR	1.0E-05	5.14E-07	Y
Hazard Index	1	0.016	Y

[11] https://deq.nd.gov/publications/AQ/policy/Modeling/Air_Toxics_Policy.pdf

7. SUMMARY AND CONCLUSIONS

Upon Trinity's review and third-party analysis of the modeling submitted by DCC, the following is concluded:

- DCC followed applicable state and Federal guidance in their modeling protocol.
- DCC's modeling was conducted to demonstrate that emissions from the Project are expected to comply with North Dakota Ambient Air Quality Standards (ND AAQS). Emissions associated with operating the facility after the Project are not expected to cause or contribute to a violation of the ND AAQS as listed in NDAC 33.1-15-02-04. Results of the modeled impacts for the ND AAQS are displayed in Figures 1-1, 5-1, and 5-2.
- The air toxics analysis conducted by DCC follows the procedure put forth in the Department's Air Toxics Policy. The results indicate that the expected MICR and HI thresholds are in compliance with the Air Toxics Policy.

APPENDIX A. PLOTS AND FIGURES

Figure A-1. Site Layout

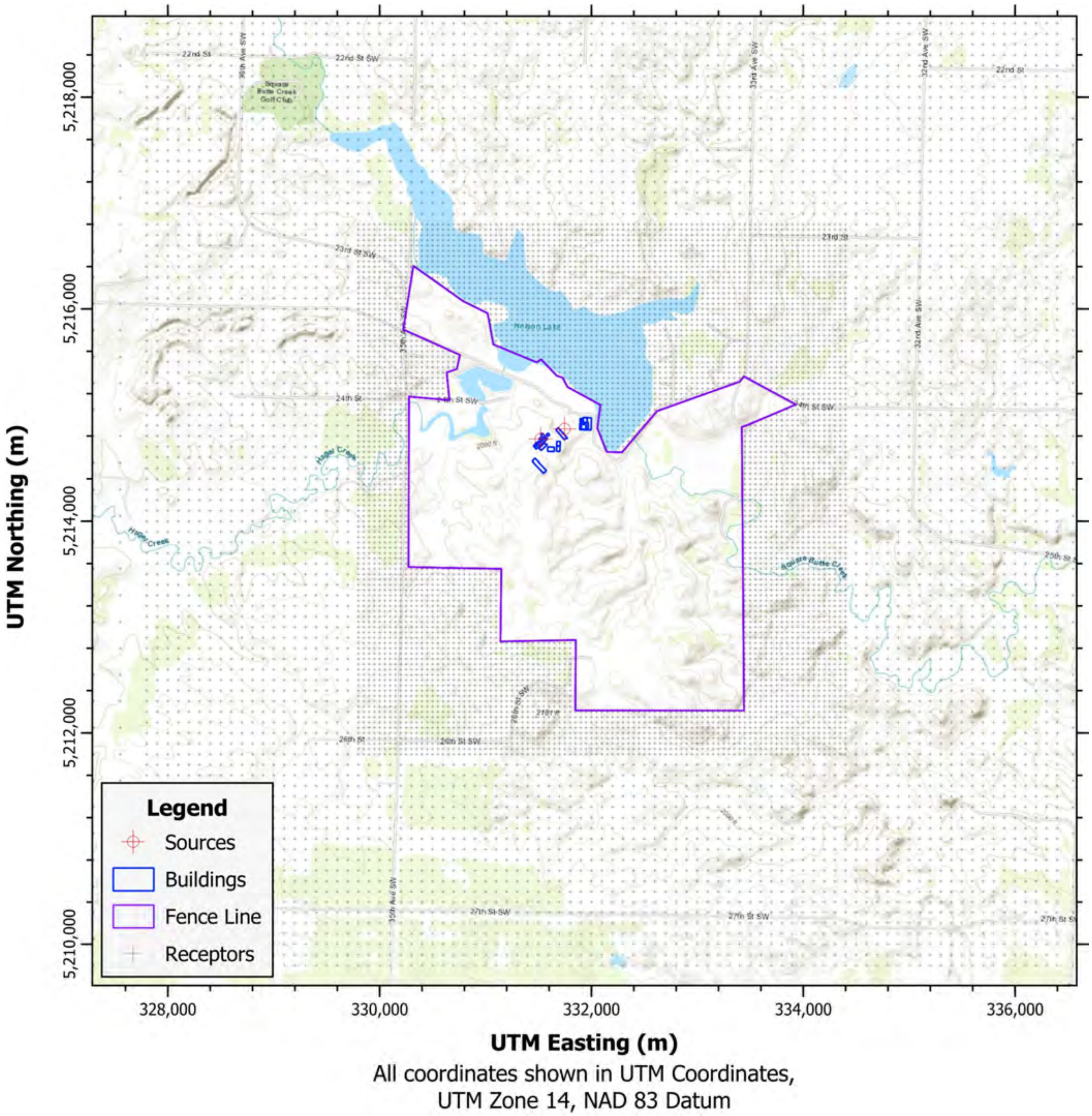
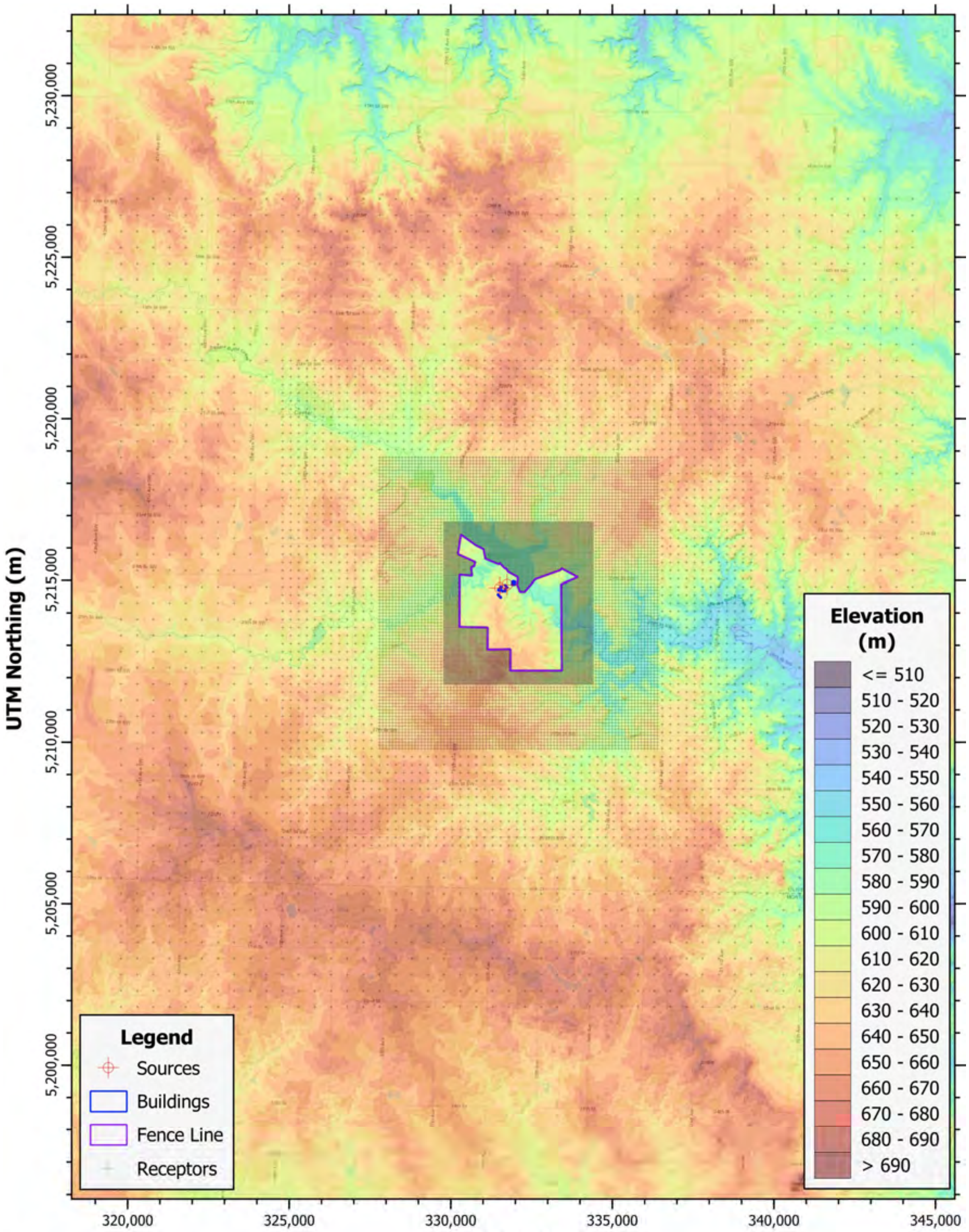


Figure A-2. Terrain



All coordinates shown in UTM Coordinates,
UTM Zone 14, NAD 83 Datum

Figure A-3. Wind Rose for Beulah Station (10-meter level) for 2017-2021

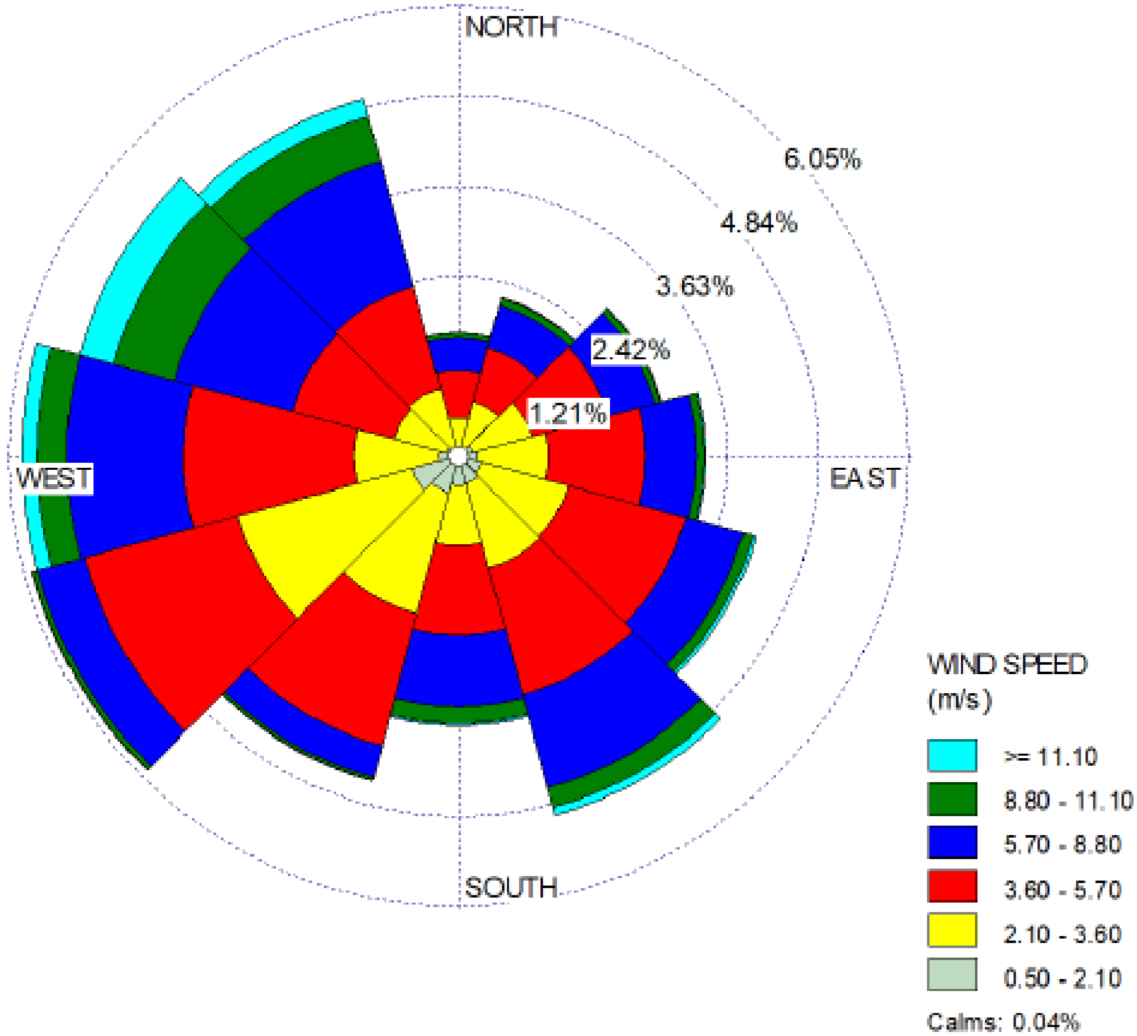


Figure A-4. Receptor Grid

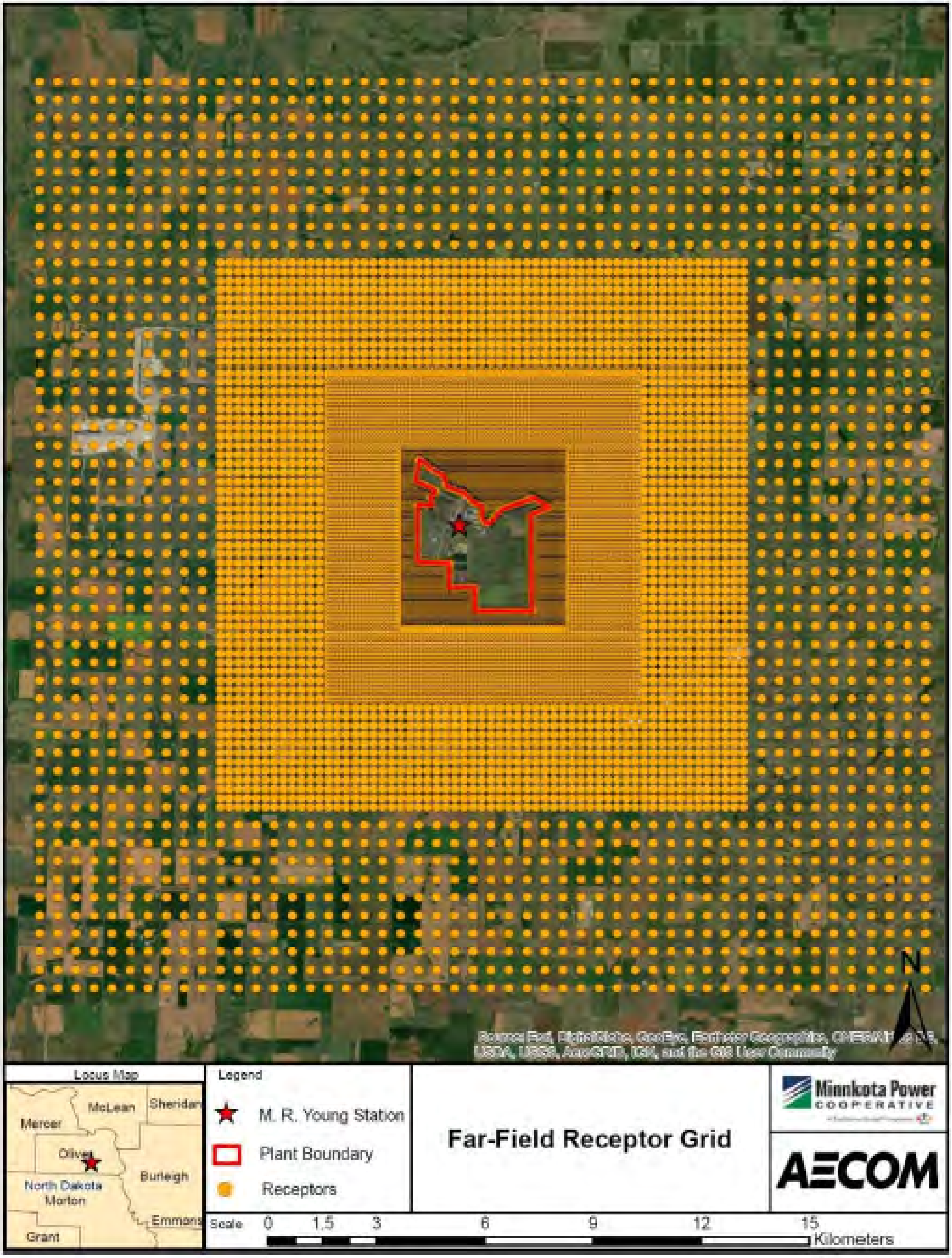


Figure A-5. 1-Hour NO_2 ND AAQS Concentrations for Mode 2

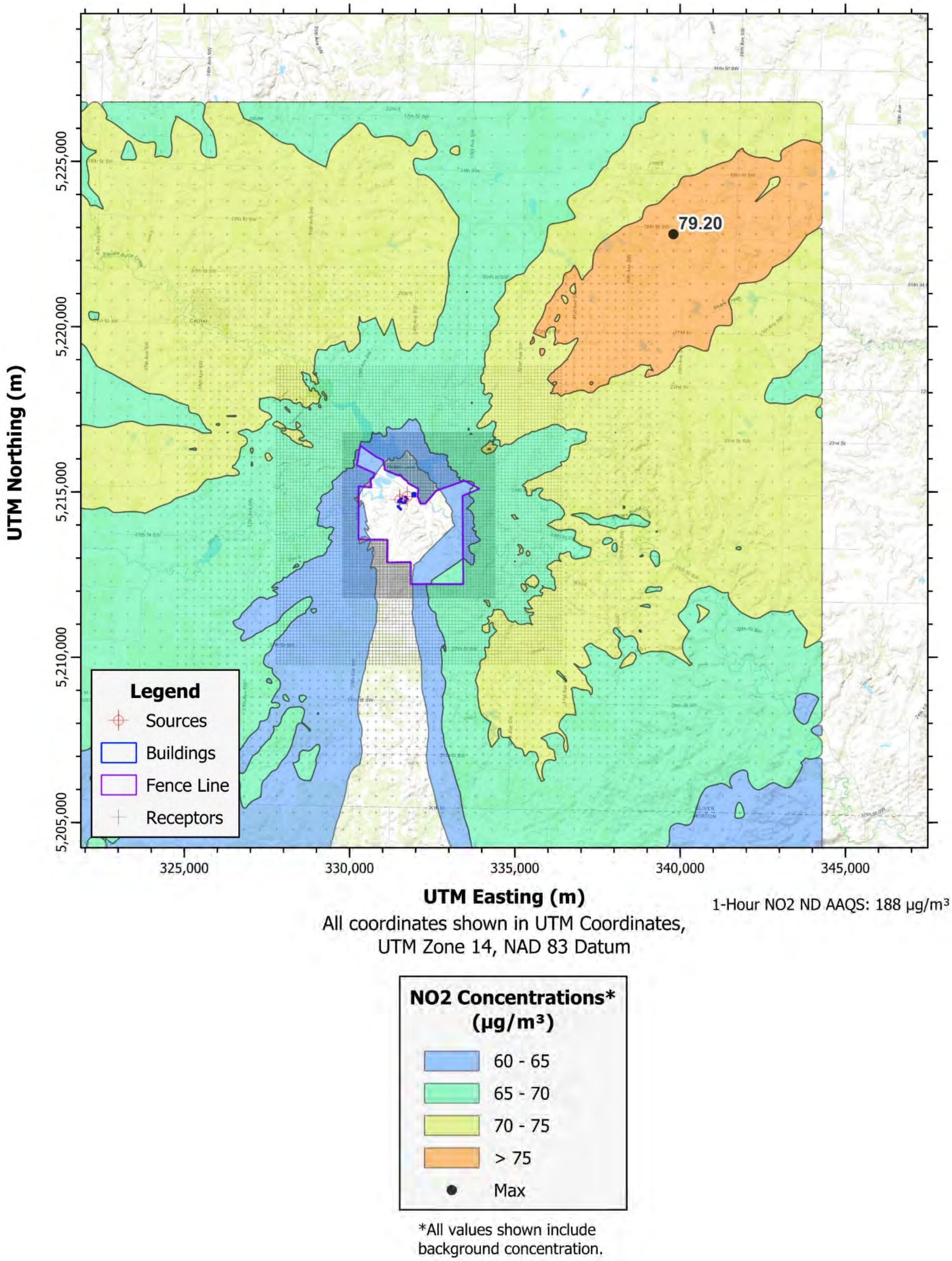


Figure A-6. Annual NO_2 ND AAQS Concentrations for Mode 2

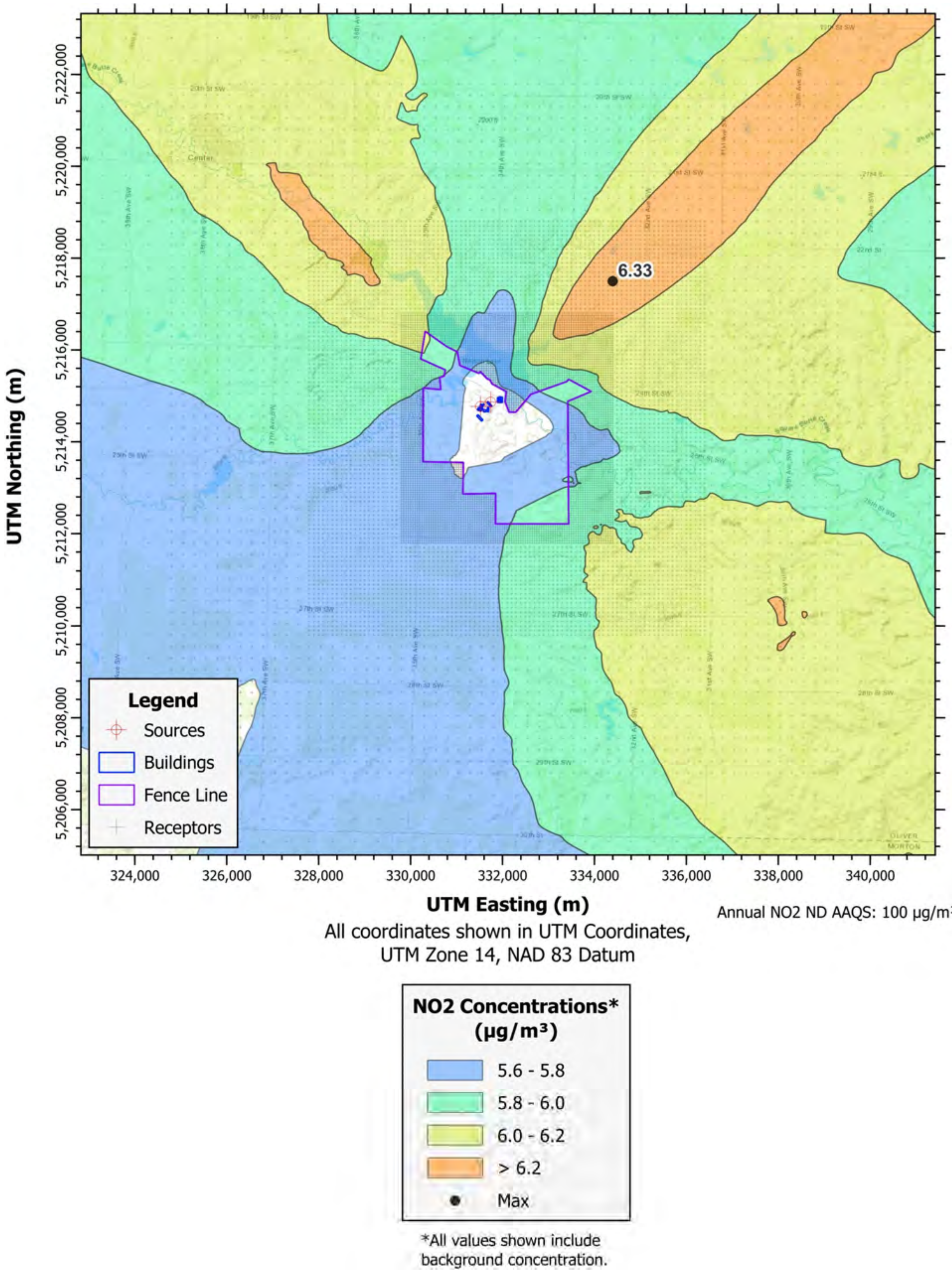


Figure A-7. 24-hour PM_{10} ND AAQS Concentrations for Mode 2

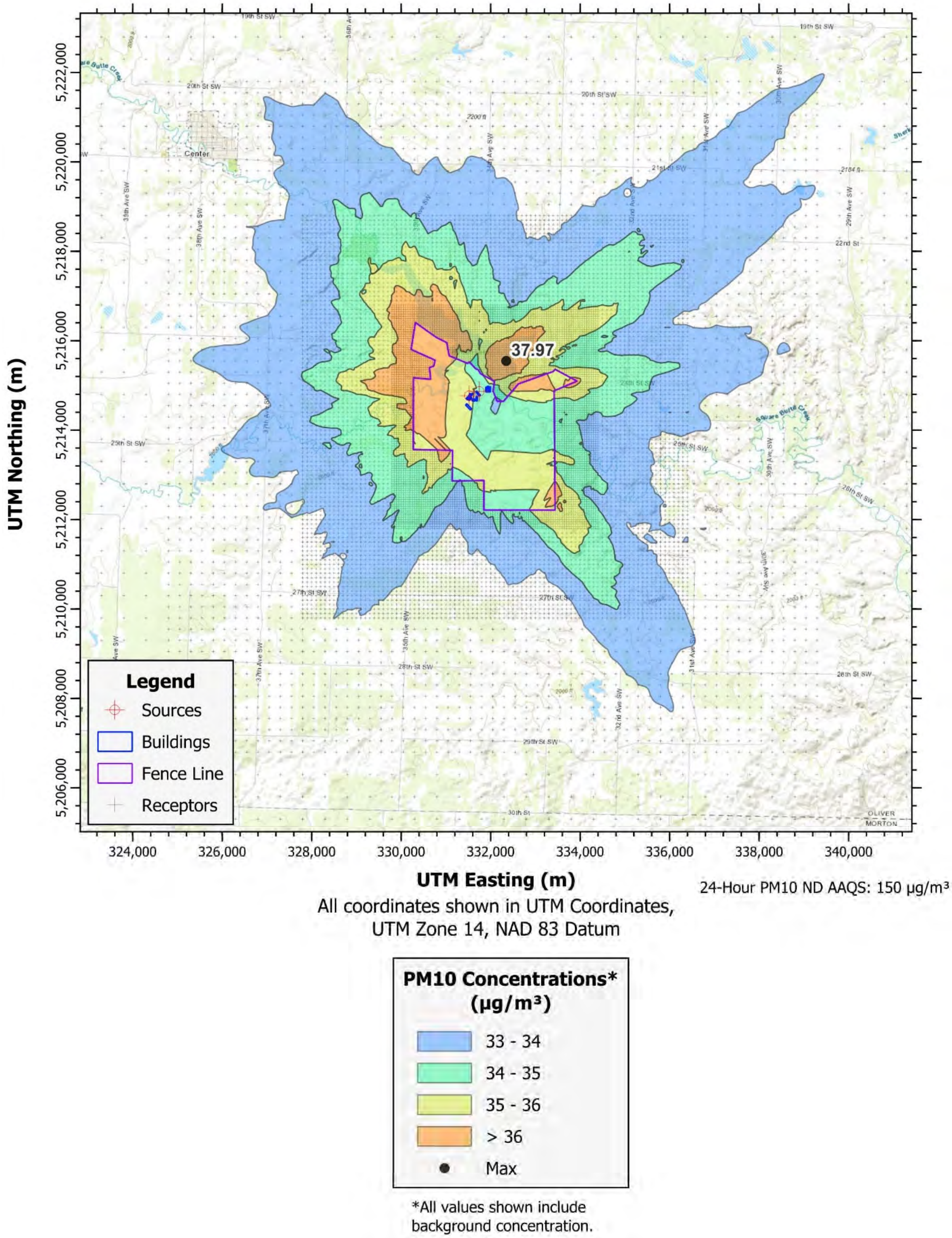


Figure A-8. 24-hour $PM_{2.5}$ ND AAQS Concentrations for Mode 2

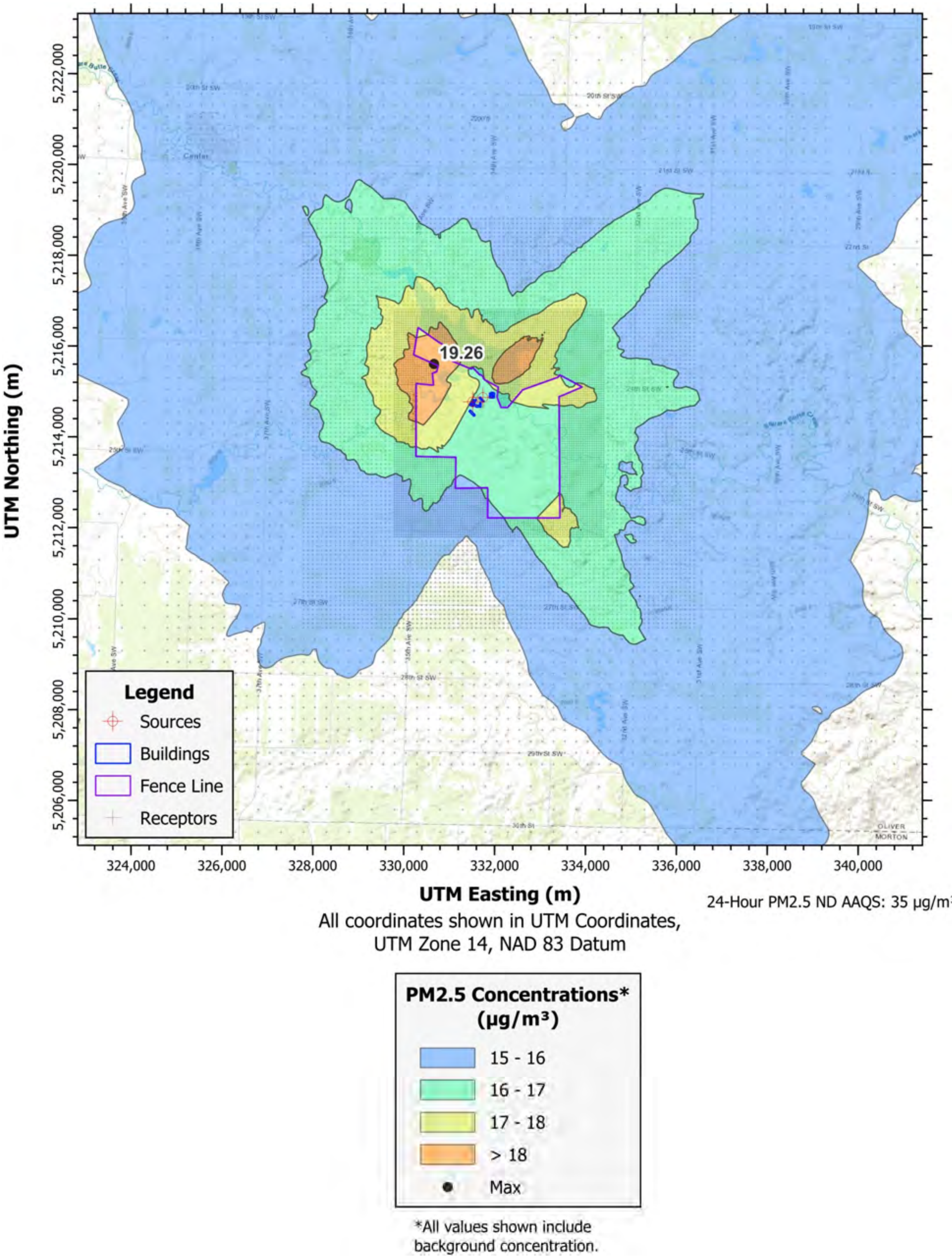


Figure A-9. Annual $PM_{2.5}$ ND AAQS Concentrations for Mode 2

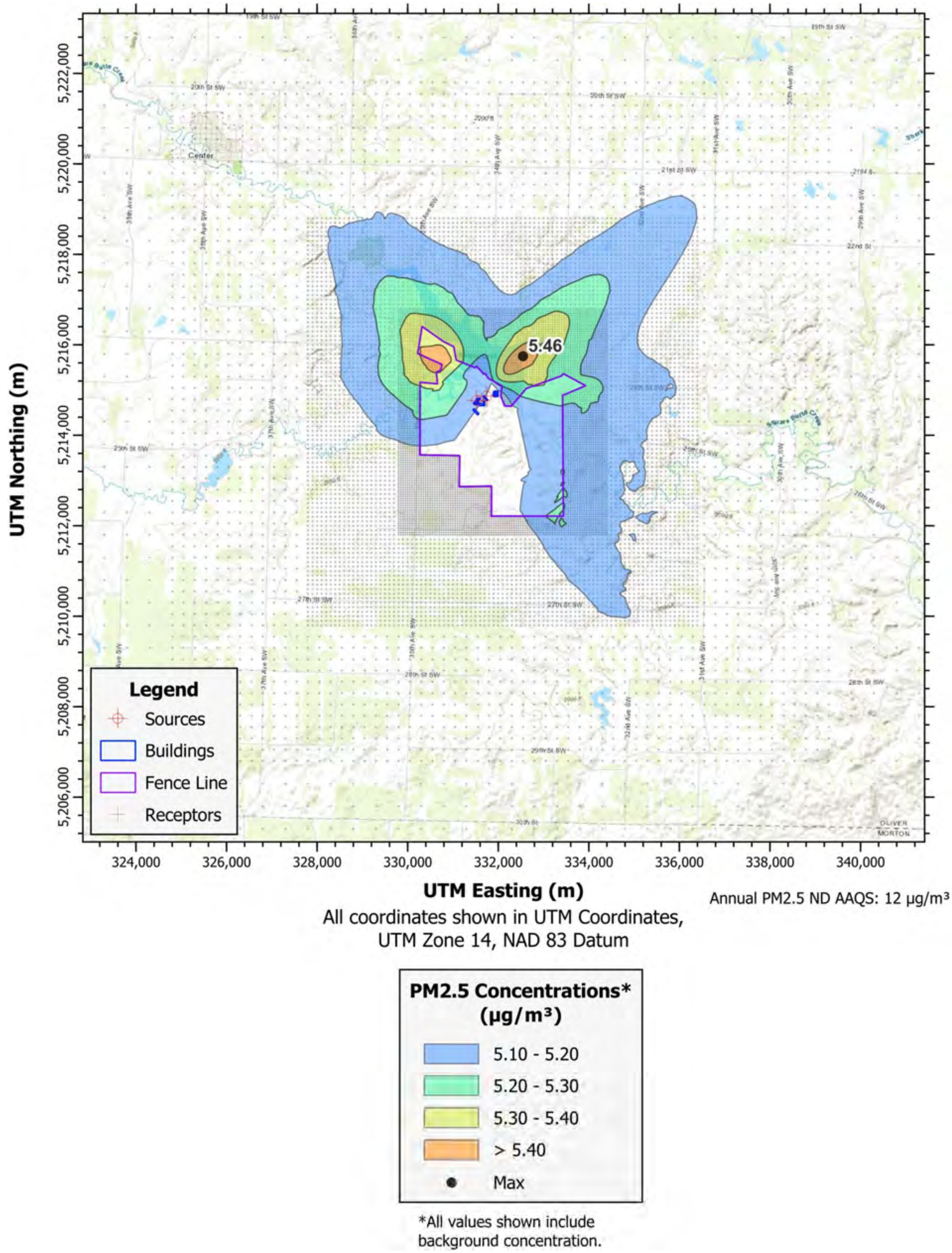


Figure A-10. 1-hour SO_2 ND AAQS Concentrations for Mode 2

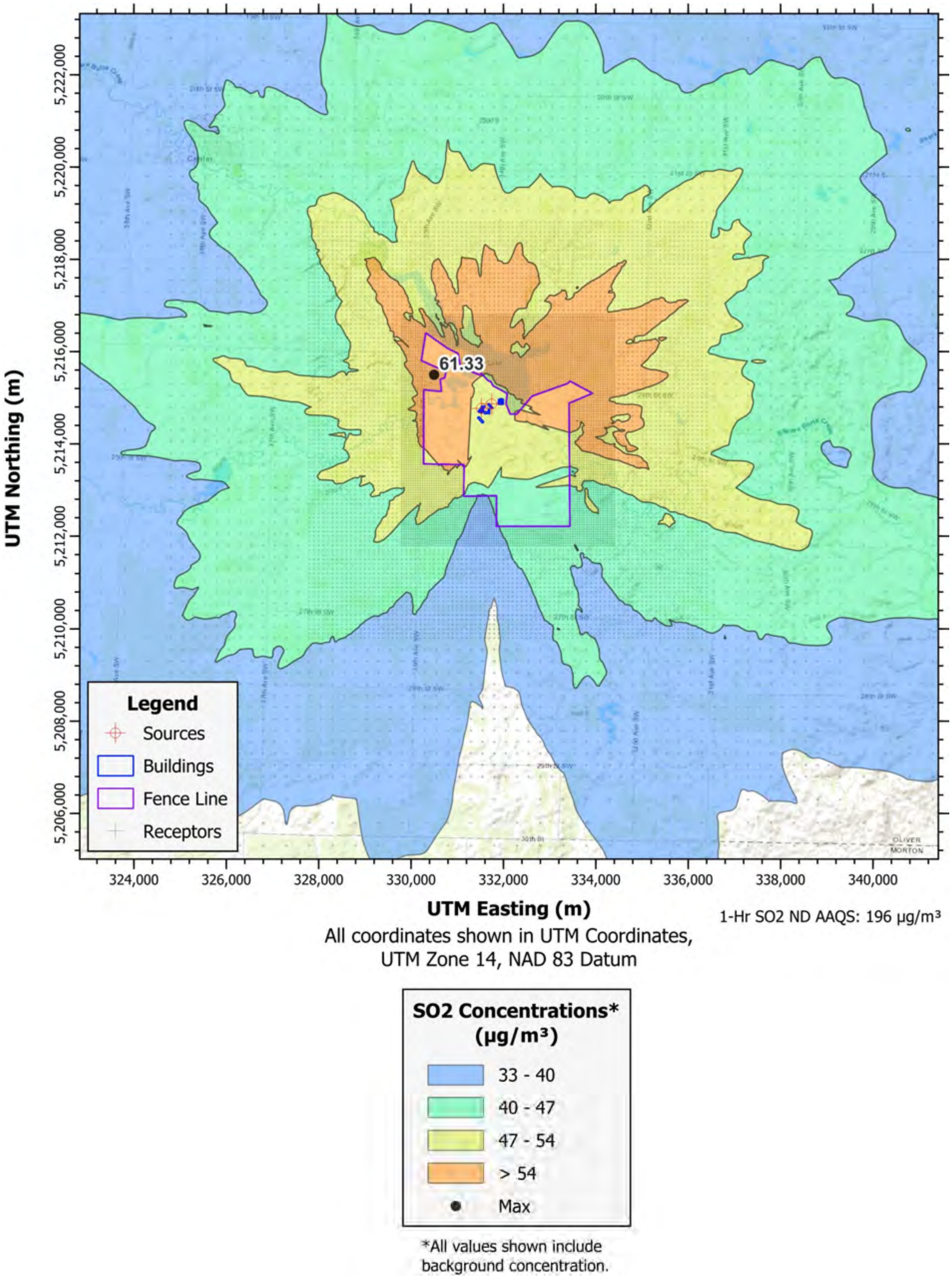
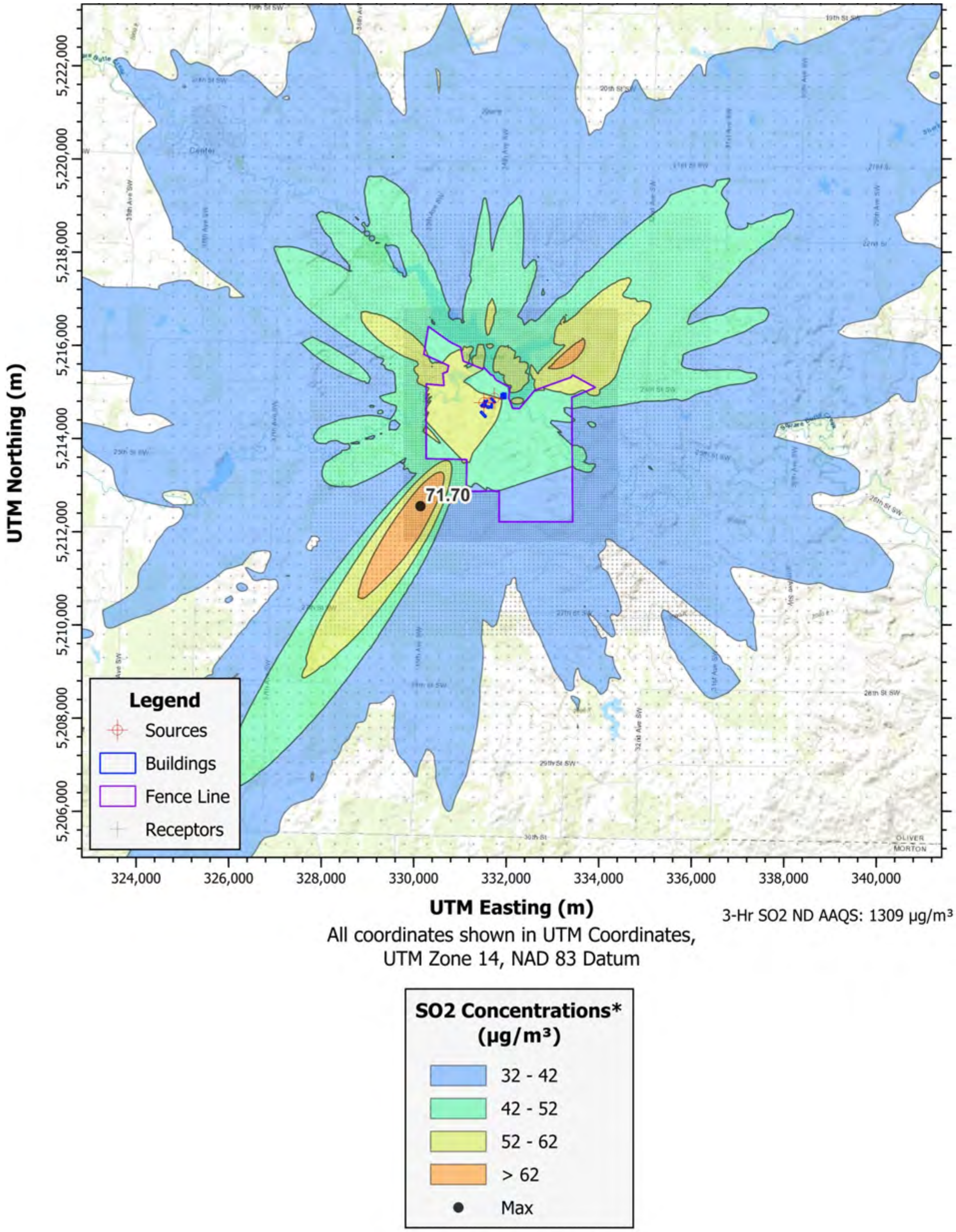


Figure A-11. 3-hour SO_2 ND AAQS Concentrations for Mode 2



*All values shown include background concentration.

Figure A-12. 24-hour SO_2 ND AAQS Concentrations for Mode 2

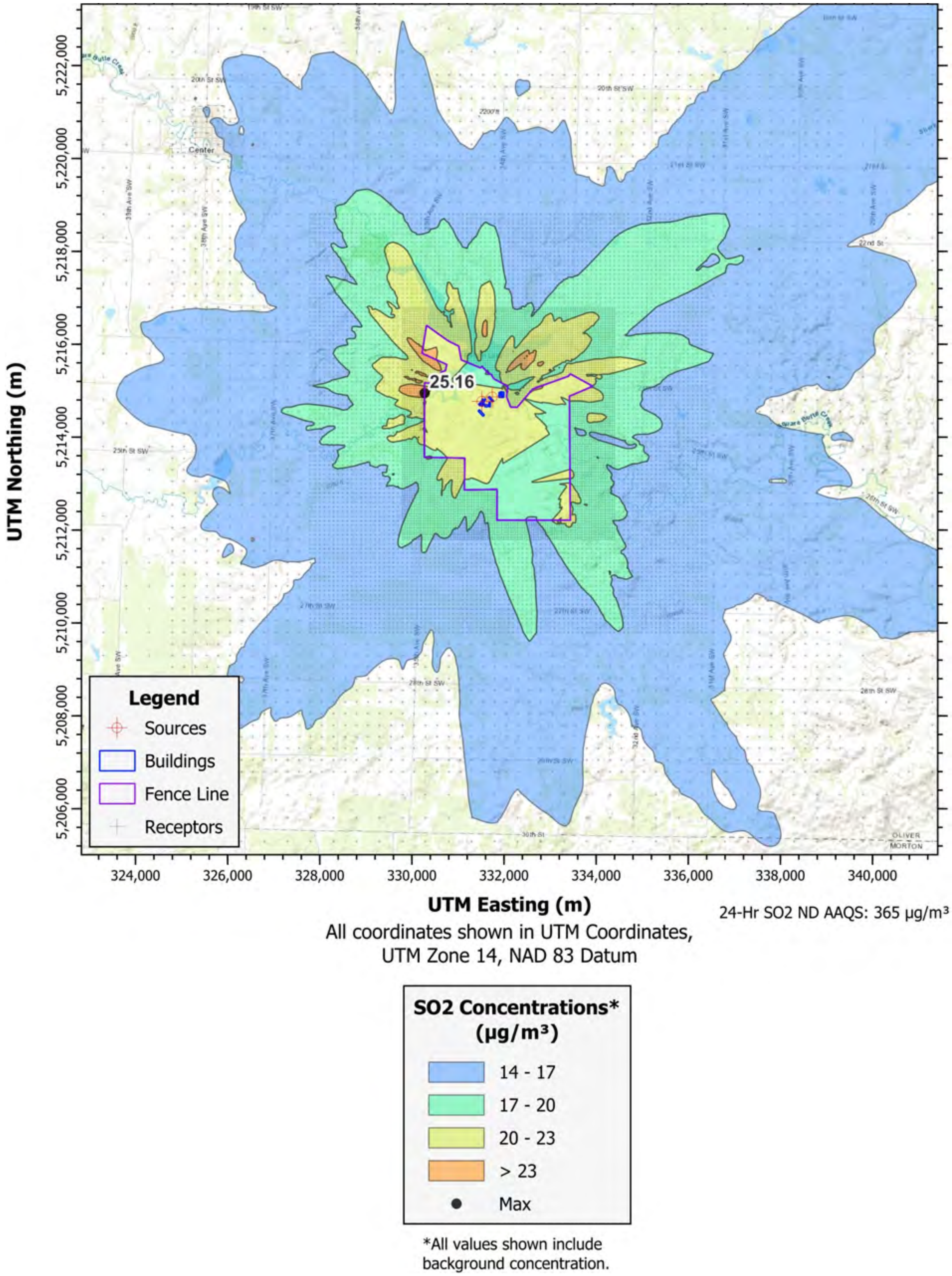


Figure A-13. Annual SO_2 ND AAQS Concentrations for Mode 2

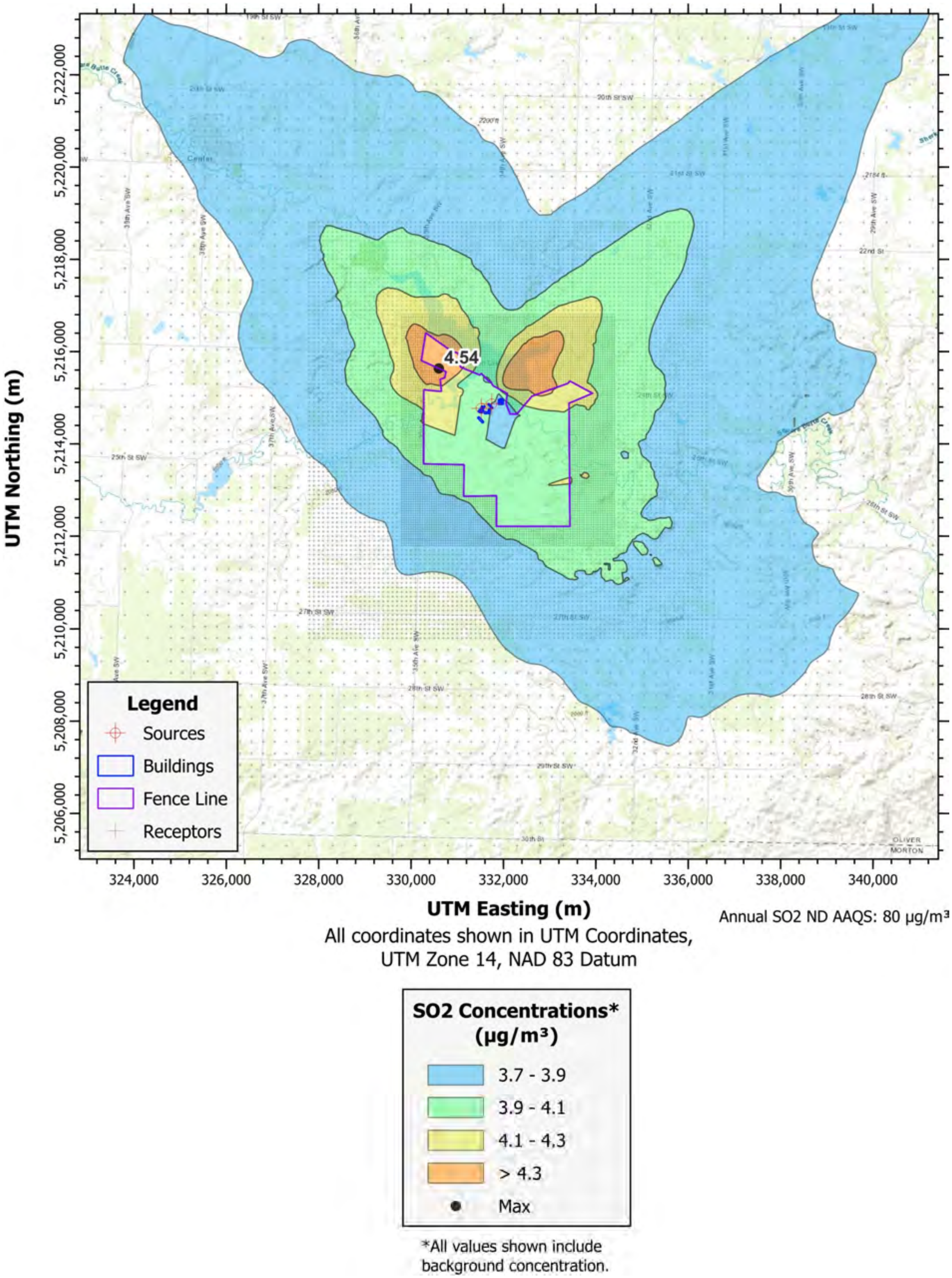
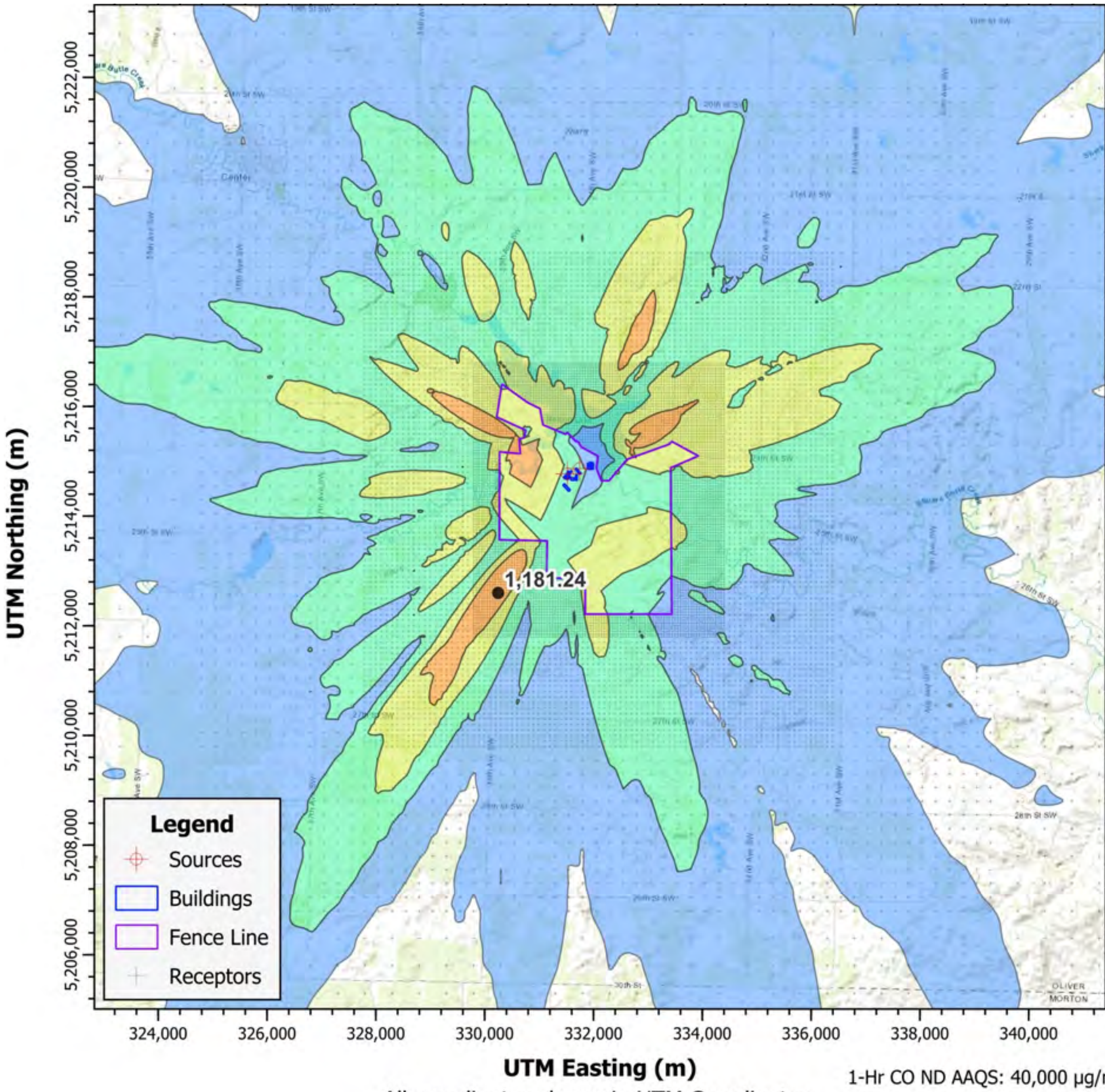


Figure A-14. 1-hour CO ND AAQS Concentrations for Mode 2



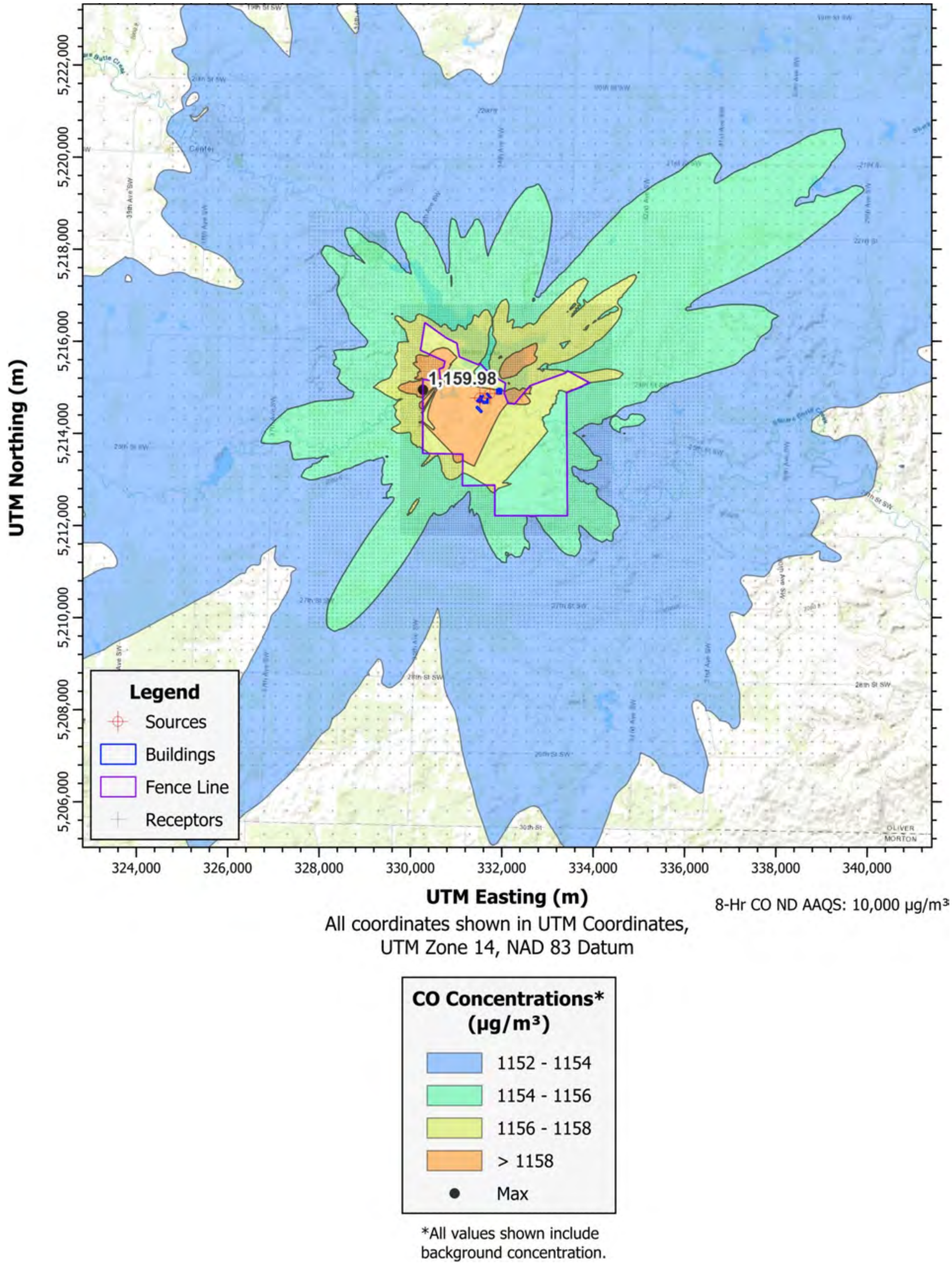
1-Hr CO ND AAQS: 40,000 µg/m³

All coordinates shown in UTM Coordinates,
UTM Zone 14, NAD 83 Datum

CO Concentrations* (µg/m³)
1160 - 1165
1165 - 1170
1170 - 1175
> 1175
Max

*All values shown include background concentration.

Figure A-15. 8-hour CO ND AAQS Concentrations for Mode 2



APPENDIX K – COMMENT RESPONSE DOCUMENT

U.S. Department of Energy

DOE/EA-2197D

North Dakota CarbonSAFE: Project Tundra

Draft
Environmental Assessment

APPENDIX K
COMMENT RESPONSE DOCUMENT

INTENTIONALLY LEFT BLANK

Table of Contents

APPENDIX K COMMENT RESPONSE DOCUMENT

LIST OF TABLES

INTENTIONALLY LEFT BLANK

ACRONYMS AND ABBREVIATIONS

Acronym	Definition
BIL	Bipartisan Infrastructure Law
BND	Bank of North Dakota
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CH_4	methane
CJEST	Climate and Economic Justice Screening Tool
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DAS	Distributed Acoustic Sensor
DOE	U.S. Department of Energy
DTS	Distributed Temperature Sensor
EA	Environmental Assessment
EIS	Environmental Impact Statement
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ERRP	Emergency Remediation and Response Plan
FOA	Funding Opportunity Announcement
GHG	greenhouse gas
GWh	gigawatt-hour
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kg	kilogram
KM CDR	Kansai Mitsubishi Carbon Dioxide Recovery
kWh	kilowatt-hour
LCA	Life Cycle Analysis
MHI	Mitsubishi Heavy Industries
Minnkota	Minnkota Power Cooperative, Inc.
MRY	Milton R. Young Station
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
ND Water Commission	North Dakota State Water Commission
NDAC	North Dakota Administrative Code
NDDEQ	North Dakota Department of Environmental Quality
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGO	non-governmental organization
NMPA	Northern Municipal Power Agency

Acronym	Definition
NO_2	nitrogen dioxide
NPDES	National Pollutant Discharge Elimination System
OCED	Office of Clean Energy Demonstrations
PM	particulate matter
Project Tundra	North Dakota CarbonSAFE: Project Tundra
PTE	Potential-To-Emit
REMI	Regional Economic Modeling, Inc.
SC-GHG	Social Cost of Greenhouse Gas
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
SPCC Plan	Spill Prevention, Control, and Countermeasure Plan
Summit Pipeline	Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project
SWPPP	Stormwater Pollution Prevention Plan
UIC	Underground Injection Control
UST	underground storage tank
Wet ESP	Wet Electrostatic Precipitator
Wh	watt-hour

APPENDIX K COMMENT RESPONSE DOCUMENT

K.1 INTRODUCTION

The U.S. Department of Energy (DOE) prepared the Environmental Assessment (EA) for "North Dakota CarbonSAFE: Project Tundra" (Project Tundra) to evaluate the potential environmental, cultural, and socioeconomic impacts of partially funding a proposed project to design, construct, and operate an amine-based post-combustion carbon dioxide (CO_2) capture technology to treat flue gas from a separate but adjacent coal-fired power plant. Consistent with the National Environmental Policy Act (NEPA), DOE released the Draft EA for a 30-day public comment period, which ran from August 19 to September 19, 2023.

This appendix summarizes the Project Tundra Draft EA public review process and provides information on responses to the comments received during the 30-day public comment period. The appendix is organized into the following sections:

- Section K.2 presents an overview of the agency and public review and comment process initiated by DOE. It also presents the number of comments submitted during the public comment period by entity and submission method and describes the processing of comments received.
- Section K.3 outlines the major themes associated with comments received during the comment period.
- Section K.4 provides DOE responses to the major themes outlined in Section D.3.
- Section K.5 presents comments provided by regulatory agencies, other governmental agencies, non-governmental organizations (NGOs), and the public.

K.2 AGENCY AND PUBLIC REVIEW AND COMMENT PROCESS

DOE published a Notice of Availability on its website and in the Bismarck Tribune Newspaper announcing the availability of the Draft EA and the 30-day comment period running from August 19, 2023 to September 19, 2023. Along with the newspaper notifications, DOE sent letters to notify stakeholders and potentially interested parties. The notifications contained a link to an electronic version of the Draft EA posted on the DOE's National Energy Technology Laboratory (NETL) website and announced the availability of hard copies at two libraries in North Dakota. Chapter 5 of the EA, Distribution List, specifies the agencies, NGOs, Federally recognized Native American Tribes, and individuals to whom notifications were sent. Table K-1 summarizes the hard copies and notifications sent to stakeholders.

Table K-1. Draft EA Notification and Distribution

Group	Number of Hard Copies	Number of Notification Letters
Federal Agencies	0	6 (via email)
State Agencies	0	6 (via email)
Native American Tribes	6	6
Non-Governmental Organizations	0	17 (via email)
Libraries	2	2

During the public comment period, federal agencies, state and local governmental entities, North Dakota Tribal governments, and members of the public were invited to submit electronic comments via regulations.gov or email, or written comments via the U.S. mail. Table K-2 summarizes the number of comments received by method of submission and entity type. Entities submitting comments included federal and state government agencies, NGOs, and the general public. No comments were received from Tribal representatives.

Table K-2. Numbers of Comment Documents Received by Entity and Method of Submission

Entity	Method of Submission		Total
	askNEPA@hq.doe.gov	Email	
Elected Official	0	0	0
Federal Agency	0	1	1
State Agency	0	1	1
Local Agency	0	0	0
NGO/Advocacy Group	0	3	3
General Public	1	4	5

Upon receipt, all written comment documents were assigned a unique number for tracking during the comment response process. All comment documents were then reviewed for inclusion in this appendix and development of major comment themes. In processing the comment documents, each document was analyzed to identify individual comments and DOE prepared responses to the applicable comment themes.

In preparing this revised Draft EA, DOE reviewed all comments received as part of the public comment period. The public comment period closed on September 19, 2023, but DOE considered late comments in preparation of the revised Draft EA. Comments that DOE determined to be outside the scope of the Project Tundra EA are acknowledged as such in this appendix. Policy experts, subject matter experts, and NEPA specialists responded to the remaining substantive comments, as appropriate. This approach served to focus the revision process and ensure consistency throughout the final document. The comments were considered in determining whether the alternatives and analyses presented in the Draft EA should be modified or augmented, whether information presented in the Draft EA needed to be corrected or updated, and generally whether additional clarification was appropriate to facilitate clearer communication of information. Areas where DOE made changes to the revised Draft EA are noted in Section K.4, Comment Responses. Change bars in the margins of pages indicate where substantive changes were made and where text was added or deleted. Editorial changes are not marked. Notable changes made to the revised Draft EA include clarifications regarding the proposed federal action, purpose and need; and no-action alternative; and revisions to the Life Cycle Analysis (LCA) and Social Cost of Greenhouse Gases (SC-GHG).

K.3 MAJOR COMMENT THEMES

Upon review of the comments received on the Draft EA, DOE categorized topics of interest or “themes” to be addressed. These include topics of common interest or concern, as indicated by their recurrence in comments, or technical topics that warrant a more detailed discussion. This section summarizes the comments received on a topic of interest, followed by DOE’s response.

Table K-3 presents the major themes and sub-themes on which DOE received substantive comments. This table also provides the location(s) in the revised Draft EA where the topic is discussed and lists comment sub-themes related to the central topic.

Table K-3. Major Comment Themes

Theme	Revised Draft EA Location	Sub-Theme Coding System[a]
NEPA Process	Chapter 1	Summary Comment 1: General/NEPA Process Summary Comment 2: Purpose and Need Summary Comment 3: National Climate Goals Summary Comment 4: Request for Environmental Impact Statement Summary Comment 5: Agency and Tribal Consultation
Proposed Action	Chapter 1	Summary Comment 6: Connected Actions
Alternatives	Chapter 2	Summary Comment 7: Alternatives Considered Summary Comment 8: No-Action Alternative
Project Facilities and Carbon Capture Technology	Chapter 2	Summary Comment 9: Carbon Capture and Sequestration Technology/Design Summary Comment 10: Co-Benefits of Carbon Capture Summary Comment 11: 45Q Tax Credits
Impact Analysis	Chapter 3	Summary Comment 12: Geology/Geologic Storage Summary Comment 13: Water Resources Summary Comment 14: Solid and Hazardous Waste Summary Comment 15: Reliability and Safety
Socioeconomics and Environmental Justice	Sections 3.13 and 3.15	Summary Comment 16: Socioeconomic Benefits Summary Comment 17: Environmental Justice
Social Cost of Greenhouse Gases (SC-GHG)	Sections 3.3 and 3.17	Summary Comment 18: SC-GHG Summary Comment 19: SC-GHG Equivalencies
Initial Life Cycle Analysis (LCA)	Sections 2.5.6, 3.3, and Appendix E	Summary Comment 20: Initial LCA Approach Summary Comment 21: Initial LCA Functional Unit Summary Comment 22: Sulfur Hexafluoride (SF_6) Summary Comment 23: Initial LCA Methodology and Assumptions Summary Comment 24: Initial LCA Conclusions Summary Comment 25: Air Emissions and Modeling Summary Comment 26: Presumption of Zero Measurable Leakage

K.4 THEMATIC COMMENT RESPONSES

This section provides a summary of each major comment theme identified in Table K-3 and a synopsis for the related sub-themes; refer to the table key for finding responses for a specific topic. Commenters can refer to the theme and sub-theme topics in this appendix to view DOE responses. DOE provides a response to each sub-theme that includes references to relevant information presented in the EA and documents any changes incorporated into this revised Draft EA as a result of the comments.

K.4.1 NEPA Process

DOE received comments related to the purpose of and need for the project. This included comments regarding general opposition to the project, the NEPA process, the purpose and need statement, general quality of the August 2023 Draft EA document, and agency and Tribal consultation/coordination.

Theme	Revised Draft EA Location	Sub-Themes
NEPA Process	Chapter 1	Summary Comment 1: General/NEPA Process Summary Comment 2: Purpose and Need Summary Comment 3: National Climate Goals Summary Comment 4: Request for Environmental Impact Statement Summary Comment 5: Agency and Tribal Consultation

Summary Comment 1: General/NEPA Process

Synopsis:

These comments were general in nature and were related to the NEPA process, opposition to the project, or other topics outside the scope of the EA.

Response to Comments 1-3, 2-1, 4-1, and 10-2:

The NEPA process seeks to include environmental considerations in any federal agency planning, undertaking, or decision-making. The EA is prepared to objectively assess the environmental impacts of partially funding the proposed Project Tundra. The project would include new equipment for the capture and geologic storage of CO_2 adjacent to the existing, separately owned lignite-fired Milton R. Young Station (MRY) in Center, Oliver County, North Dakota. The project would utilize Mitsubishi Heavy Industries' (MHI) Kansai Mitsubishi Carbon Dioxide Recovery (KM CDR) amine-based post-combustion carbon capture technology. The project would purchase and treat the flue gas from MRY to produce a final CO_2 product. The purpose of the EA is to provide decision-makers and other stakeholders with information needed to understand the potential environmental impacts resulting from an action, including mitigation and conservation measures warranted to protect a resource or minimize impact to a resource. Analyses are based on best available data, results of surveys, and academic and agency research and reports to characterize the resources present within the project area (region of influence) and the potential for adverse effects. Where possible, the project design would incorporate best management practices and/or mitigation measures to reduce potential for adverse impacts.

The purpose of a Draft EA is to publish, for public review and comment, an unbiased review of the direct and indirect impacts to the human environment that would potentially result if DOE were to fund a project. A Draft EA is pre-decisional and is intended to inform DOE and the public of potential impacts and to elicit comments from the public, stakeholders, and other agencies. Its function is not to recommend any action by DOE or to promote the merits of a project or technology. Thus, the Draft EA did not include a recommendation regarding the project.

Regarding comments in opposition to the project, DOE understands there are opposing viewpoints on whether this project should proceed and appreciates the public input in the NEPA process. The revised Draft EA builds upon the previously completed Draft EA by incorporating additional text into the purpose and need and alternatives narratives and updating the LCA and SC-GHG analyses to assist in determining the potential adverse and beneficial effects on resources from the construction, operation, and maintenance of the project.

One commenter inquired about a previous Government Accountability Office (GAO) audit on an unrelated project. While GAO audit reports are tools used to assist DOE with improving future approaches on relevant activities, the topic presented is outside the scope of the EA.

Summary Comment 2: Purpose and Need

Synopsis:

Several commenters questioned the purpose and need for the project, requested a broader purpose and need statement, and expressed concerns regarding federal funding of the project.

Response to comments 2-1, 4-1, 5-1, 5-3, 5-4, 7-2, 7-3, 8-1, 8-3, 8-6, 8-7, 8-8, and 8-9:

As described in Section 1.4 of the revised Draft EA, the purpose and need for DOE action is to advance the commercial readiness of carbon capture and storage (CCS) by supporting the construction of a commercial-scale geologic storage complex and associated CO_2 transport infrastructure. In 2021, Congress passed the Bipartisan Infrastructure Law (BIL). The BIL is a once-in-a-generation investment in modernizing and upgrading American infrastructure to enhance United States competitiveness, drive the creation of good-paying union jobs, tackle the climate crisis, and ensure stronger access to economic and environmental benefits for disadvantaged communities. The BIL appropriated more than $62 billion to the DOE to invest in American manufacturing and workers; expand access to energy efficiency and clean energy; deliver reliable, clean and affordable power to more Americans; and demonstrate and deploy the technologies of tomorrow through clean energy demonstrations. DOE's BIL investments "support efforts to build a clean and equitable energy economy that achieves a zero-carbon electricity system by 2035, and to put 'the United States on a path to achieve net-zero emissions economy-wide by no later than 2050' to benefit all Americans."

Through BIL, Congress appropriated funds under both the CarbonSAFE Initiative and the Carbon Capture Demonstration Projects Program to further the development, deployment, and commercialization of technologies to capture and geologically store CO_2 emissions securely in the subsurface. Thus, DOE issued Funding Opportunity Announcement (FOA) DE-FOA-00002711 entitled "Storage Validation and Testing (Section 40305): Carbon Storage Assurance Facility Enterprise (CarbonSAFE)." Project Tundra was selected under the FOA to begin negotiations to receive a federal financial assistance award with Project Tundra.

Successful implementation of Project Tundra would potentially contribute to the rapid growth of a geographically and geologically diverse industry for secure geologic carbon storage by reducing risks and costs for future projects and bringing more storage resources into commercial classifications.

Because DOE has been instructed by Congress on how to utilize this funding, DOE does not have the authority to utilize these funds for any purpose other than commercial-scale CCS projects.

Summary Comment 3: National Climate Goals

Synopsis:

Commenters objected to the (1) characterization of the project as the only way of furthering the U.S. climate goals. Commenters further expressed that (2) the project should align with the Paris Agreement and pursue immediate retirement, and that (3) North Dakota has already shown momentum to shift to wind and solar by retiring Coal Creek Station.

Response to Comments 5-5, 5-8, and 8-26:

(1) It was not the intent of Section 1.4 to imply that a single project would be responsible for meeting the nation's goals with respect to CO_2 emissions. If selected, the project would contribute to a diverse portfolio of projects that collectively research, advance, and demonstrate the reduction of CO_2 from the energy economy, which includes the electricity generation and other industrial sectors. Section 1.4 has been updated for clarity.

(2) DOE does not speculate on the future of proposed regulations, the life-cycle decisions of a plant operator, or any other future decisions outside of its delegated statutory authority. The operational life span and future retirement of MRY Unit 1 and Unit 2 are based on many factors outside of DOE's purview and the scope of this EA. Projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. It is not reasonably foreseeable to identify a specific life span limit for MRY.

(3) The commenter is mistaken. Although wind farms have been created nearby, Coal Creek Station was not retired. The current owner/operator of Coal Creek Station clearly states that its climate objectives culminate with CCS at Coal Creek. Coal Creek Station has been selected for a CarbonSAFE Phase III project.

Summary Comment 4: Request for Environmental Impact Statement

Synopsis:

Several commenters recommended that the DOE find the environmental impacts would be significant, and therefore an Environmental Impact Statement (EIS) should be prepared.

Response to Comments 5-27, 8-1, 8-5, 8-11, 8-13, 8-15, 8-18, and 8-25:

As required by NEPA and its supporting regulations, DOE prepares an EA for a proposed DOE action that is described in the classes of actions listed in Title 10 of the Code of Federal Regulations (CFR) Part 1021, Subpart D, Appendix C and for a proposed DOE action that is not described in any of the classes of actions listed in Appendices A, B, or D to subpart D. An EA may result in a Finding of No Significant Impact (FONSI) or a determination to prepare an EIS, if significant impacts are present that are not mitigated. At this time, DOE is utilizing the information it has gathered while preparing this EA to determine whether preparation of an EIS is appropriate.

Summary Comment 5: Agency and Tribal Consultation

Synopsis:

One commenter suggested that DOE failed to consult with local agencies and Tribes, Indigenous Peoples, and leaders.

Response to Comment 5-23:

As part of the NEPA process, DOE consulted the federal, state, Tribal governments, and local agencies listed in Chapter 5 (Distribution List) of the revised Draft EA. In accordance with Section 106 of the National Historic Preservation Act, this outreach included consulting with the following federally recognized Tribal Nations in the project area: Apache Tribe of Oklahoma; Fort Belknap Indian Community of the Fort Belknap Reservation of Montana; and Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.

K.4.2 Proposed Action

DOE received comments related to potential connected actions to the proposed project, specifically the proposed Summit Pipeline.

Theme	Revised Draft EA Location	Sub-Themes
Proposed Action	Chapter 2	Summary Comment 6: Connected Actions

Summary Comment 6: Connected Actions

Synopsis:

One commenter asserts that the proposed project and the Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project (Summit Pipeline) are connected actions. Two commenters suggested that potential use of captured CO_2 for enhanced oil recovery (EOR) carry environmental impacts that are within the scope of this EA.

Response to Comments 5-26, 8-29, 8-30, 8-31, and 8-32:

Project Tundra is not connected to the proposed Summit Pipeline. Project Tundra does not require CO_2 from the proposed Summit Pipeline to meet the goals and objectives of the project. As currently designed, the CCS project would only operate when MRY is operating, because the CO_2 is captured from the flue gas of MRY. The reference to the Summit Pipeline in Section 3.17, Cumulative Impacts, was referring to the reasonably foreseeable case that the storage reservoir developed under Project Tundra could be used to permanently sequester other anthropogenic CO_2, such as the geographically proximate proposed Summit Pipeline, in the future.

The objective of the CarbonSAFE Initiative is to permanently sequester commercial quantities of CO_2 in subsurface geologic formations. Projects proposing EOR are disallowed under the CarbonSAFE Initiative because they do not meet the requirements DOE has set forth in FOAs DE-FOA-0002711 for CarbonSAFE Phase IV (Construction) or DE-FOA-0002962 for Carbon Capture Demonstration. Use of captured CO_2 for EOR is therefore not in the scope of the EA.

K.4.3 Alternatives

DOE received comments related to consideration of alternatives in addition to the no-action alternative.

Theme	Revised Draft EA Location	Sub-Themes
Alternatives	Chapter 2	Summary Comment 7: Alternatives Considered Summary Comment 8: No-Action Alternative

Summary Comment 7: Alternatives Considered

Synopsis:

Comments stated that DOE should consider a variety of effects and variations of alternatives in addition to the no-action alternative, including operator decision on maintenance and operations of the MRY facility, proposed regulations from other agencies, and resource replacement impacts.

Response to Comments 3-1, 5-6, 5-7, 5-9, 7-1, 7-2, 7-3, 7-4, 8-2, 8-10, 8-11, 8-12, 8-18, 8-20, 8-23, and 8-26:

NEPA requires agencies to consider a reasonable range of alternatives to the proposed agency action, including an analysis of any negative environmental impacts of not implementing the proposed agency action in the case of a no action alternative that are technical and economically feasible and meet the purpose and need of the proposal.

In 2016, Congress directed DOE to develop CCS at a commercial scale. DOE created the CarbonSAFE Initiative in order to comply with that directive. The purpose and need for agency action is not “tailored to the applicant’s goals;” rather, it is responsive to DOE's “statutory authority and goals” as well as Congressional mandates that require commercial-scale CCS. Thus, DOE only has the authority to choose to fund or not to fund any of the projects applying for funding under a competitive FOA. DOE does not have the ability to use the Congressionally appropriated funds for any purpose other than commercial-scale CCS. DOE’s **Proposed Action** is to provide cost-shared funding for Project Tundra and the only alternative is not funding the proposed project. Alternatives to Minnkota’s **proposed project** include funding a different project that meets the goals and objectives of the same FOA or not funding any projects submitted under the FOA. In this case, the projects that are eligible to apply for funding under DE-FOA-00002711 consist of the other CarbonSAFE Phase III projects, which will undergo separate NEPA analysis and documentation. There are currently four other projects undergoing NEPA review:

- DOE/EA-2194: Wyoming CarbonSAFE
- DOE/EA-2196: Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO_2S
- TBD: San Juan Basin CarbonSAFE
- TBD: Illinois Storage Corridor CarbonSAFE

There are additional projects being selected for CarbonSAFE Phase III, which will also undergo NEPA review. Please see DOE's website https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe for a current list of those projects. The CarbonSAFE Initiative Draft EA and EIS documents will continue to be published for review at https://netl.doe.gov/node/6939 and https://netl.doe.gov/library/eis, respectively. All CarbonSAFE Phase III projects will be analyzed for potential impacts separately and will not be discussed further in this EA. DOE’s consideration of reasonable alternatives to this project in this document is therefore limited to the no-action alternative.

Moreover, an agency is not expected to engage in forecasting and speculation that would ultimately be unhelpful in its decision making, especially when the agency lacks any power to act on such speculation. “NEPA’s purpose is not to generate paperwork or litigation, but to provide for informed decision making and foster excellent action” (40 CFR § 1500.1). Additionally, DOE has no control over the continued operation of MRY, so an alternative that involves shutting down or reducing power levels is outside the scope of DOE's authority.

Summary Comment 8: No-Action Alternative

Synopsis:

Comments stated that DOE should consider a no-action alternative that does not include continued operation of MRY at current levels, and instead includes decommissioning of the plant at intervals selected by the commenters.

Response to Comments 3-1, 5-6, 5-7, 5-9, 7-1, 7-3, 8-2, 8-8, 8-10, 8-11, 8-12, 8-13, 8-18, 8-20, 8-23, 8-26:

In Section 2.3, it is clearly stated that the no-action alternative, in which DOE would not fund the project, is assumed to be a no-build option, with CO_2 emissions continuing from MRY. This no-action alternative provides a meaningful comparison between the current environment at the proposed project location and the potential impacts attributable to DOE's proposed action. DOE does not speculate on the future of proposed 111(b) and 111(d) regulations, the life-cycle decisions of a plant operator, or any other future decisions outside of its delegated statutory authority. Similarly, DOE does not speculate that the CCS project will proceed with independent funding, which would result in a Draft EA analysis with no net impacts. The operational life span and future retirement of Unit 1 and Unit 2 is based on many factors outside of DOE's purview and the scope of this EA. Projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. It is not reasonably foreseeable to identify a specific life span limit for MRY in the alternatives for this EA.

K.4.4 Project Facilities and Carbon Capture Technology

DOE received comments related to the effectiveness of the proposed CCS technology, the co-benefits of carbon capture, and the applicability of the 45Q tax credits.

Theme	Revised Draft EA Location	Sub-Themes
Project Facilities and Carbon Capture Technology	Chapter 2	Summary Comment 9: Carbon Capture and Sequestration Technology/Design Summary Comment 10: Co-Benefits of Carbon Capture Summary Comment 11: 45Q Tax Credits

Summary Comment 9: Carbon Capture and Sequestration Technology/Design

Synopsis:

DOE received several comments on the design of the CCS that asserted that DOE incorrectly accounted for the capture design in the EA and LCA analysis.

Response to Comments 5-5, 5-13, 5-14, 5-25, 5-26, 6-1, 6-2, 6-3, 6-4, 8-13, 8-15, 5-16, 8-17, 8-19, 8-22, 8-24, and 8-25:

DOE appreciates that there is not one uniform capture goal, standard or requirement across agency programs and legislation for carbon capture. Thus, DOE offers a responsive narrative to assist the public in reviewing the EA and the proposed project's ability to meet DOE program goals.

Specifically, Project Tundra's CCS is designed and guaranteed by the technology vendor, MHI, to capture 95% of the CO_2 in <u>flue gas treated by the CCS system</u>. This corresponds to 13,000 short tons per day (11,793 metric tons per day) of CO_2 when operating at its full design capacity. For this generating station, the CCS capacity is approximately the equivalent of 530 megawatts (MW) out of the 734 MW total station gross capacity (Unit 2 gross rating is 477 MW and Unit 1 gross rating is 257 MW).

The design of this CCS system to simultaneously accept and process flue gas from Unit 1 and Unit 2 permits the system to capture much more CO_2 than capture systems that are paired with a single generating unit. The CCS is designed and sized to process 100% flue gas from Unit 2 (the larger of the two units at the site) plus an estimated 20% of the flue gas from Unit 1 when both generating units are operating at their full capacities including flexible operational mode variations. The agility of this project design is advantageous, particularly when grid conditions require the generating units to operate at less than full capacity. During those hours that the Units are operating at a less than full capacity level, the CCS is designed to be able to process all the flue gas from the entire generating station. For example, when either of the generating units is in outage, the CCS system can continue to capture CO_2 from the other operating unit. Also, when either or both generating units are operating at lower capacity to accommodate wind power in the region, the CCS can remain at full capacity thereby maximizing the utilization of the CCS system.

The Initial LCA calculation was based upon projected annual coal usage to account for both the outages and the operation variability of the MRY facility, and thus provided a comprehensive approach to the project's LCA.

Summary Comment 10: Co-benefits of Carbon Capture

Synopsis:

Commenters requested that the co-benefits of the upstream controls of the CCS to provide flue gas inputs to the carbon processing plant be addressed.

Response to Comments 6-1 and 6-4:

Pre-treatment controls are upstream of the CO_2 absorber that ensure the desired capture efficiency in the absorber. These pre-treatment devices include a Wet Electrostatic Precipitator (Wet ESP) and a quencher that will reduce sulfur dioxide (SO_2) and particulate matter (PM) in the flue gas stream prior to reaching the absorber. These devices will only be operational during times when the CCS is operating. As such, these controls are considered a co-benefit of the carbon capture system, when it is operating.

MRY meets all state and federal standards for SO_2, nitrogen dioxide (NO_2), and PM and these emissions are monitored as required by its air permit. Any reductions in pollutant emissions in MRY flue gas that occur as a result of the CCS and its associated pretreatment are co-benefits from the project, above and beyond the emissions reduction technologies employed by Minnkota at MRY to meet the limits in its air permit and ambient air quality standards. DOE is not quantifying those co-benefits at this time, but it is a valid assumption that additional health benefits may arise from the reduction of these pollutants. In addition, these National Ambient Air Quality Standards (NAAQS) are established for these pollutants to protect public health including sensitive populations such as asthmatics, children, and the elderly. Currently, all counties in North Dakota are classified as attainment or unclassified areas for all ambient air quality standards, including the county in which the CCS would be operating. The Project air quality analysis concludes that the CCS project would not cause or contribute to an exceedance of the NAAQS.

Summary Comment 11: 45Q Tax Credits

Synopsis:

Commenters questioned the applicability of 45Q tax credits to the CCS project, as well as whether the operation of the MRY facility would increase as a result of 45Q tax credit incentives.

Response to Comments 5-19, 8-19, 8-21, 8-22, 8-23, 8-24, and 8-25:

Congress creates tax credits like 45Q to encourage the deployment of new technologies. DOE does not have any jurisdiction over power plant operation or the 45Q tax credit program. The CCS unit is structured physically and commercially to have no impact on the operation or dispatch of the MRY (see response to summary comment 9). Because the dispatch of the power plant is forecasted based on its market position, and because the project sponsors have structured the CCS project to not impact power plant economics, including impacts due to available tax credits, then in both the "no build" and the "build" cases under the LCA, the dispatch should be the same.

K.4.5 Impact Analysis

DOE received comments related to the impact analysis provided in Chapter 4 of the Draft EA. Comments relate to geology, water resources, solid and hazardous waste, and reliability and safety.

Theme	Revised Draft EA Location	Sub-Themes
Impact Analysis	Chapter 3	Summary Comment 12: Geology/Geologic Storage Summary Comment 13: Water Resources Summary Comment 14: Solid and Hazardous Waste Summary Comment 15: Reliability and Safety

Summary Comment 12: Geology/Geologic Storage

Synopsis:

A commenter expressed concerns regarding the complexity of geologic carbon storage and the diverse geological conditions across regions that demand a more nuanced and site-specific approach to assessing the feasibility and reliability of such projects, and the proposed project in North Dakota alone will not be representative of geological conditions of other commercial coal-fired power plants to reduce the risks for commercial development of CCS.

Response to Comment 5-2:

DOE agrees that funding a single CCS project would not fully demonstrate the technology at a commercial scale. It is for that reason that DOE continues to issue FOAs and select a project portfolio that is geographically and geologically diverse. For a map of current CarbonSAFE projects in all phases of development, see https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe, There are currently no projects selected for CarbonSAFE Phase IV, which includes construction of the geologic storage site. In December 2023, DOE's Office of Clean Energy Demonstrations (OCED) announced the selection of three carbon capture demonstration projects under DE-FOA-00002962.

DOE notes that the development of a geologic storage unit to sequester CO_2 is complex and not all states have the geologic factors that are conducive to sequestration. North Dakota is an oil-producing state that does have extensive data on the formations making up the subsurface stratum, which has been gained through numerous seismic efforts, geologic cores, and well logging activities that have occurred over the last 70 years. Further, much data and analysis surrounding permanent geologic storage was gathered on the proposed project as a result of tasks performed under CarbonSafe Initiative Phase I, II, and III projects at this location. Finally, the state of North Dakota and the U.S. Environmental Protection Agency (EPA) have approved injection through the Underground Injection Control (UIC) Class VI permitting process. To be approved for this permit, extensive evaluations and monitoring are required. All of the project's data may be used to determine other settings in which the CCS technology may be applied.

Summary Comment 13: Water Resources

Synopsis:

Two commenters expressed concerns regarding potential impacts to surface waters, including waterbodies, non-community well protection areas, and the potential effects of the project water appropriation from the Missouri River on users downstream. These comments recommended that the project site its facilities and route the pipeline (i.e., CO_2 flowline) to avoid source water protection areas, and sensitive surface and groundwater environments. The commenters also inquired about required permits and/or permit amendments; mitigation measures that Minnkota would implement to prevent erosion and sediment loss and potential impacts to water resources, wetlands, and riparian zones/delicate flora; and restoration of areas affected by project construction.

Responses to Comments 8-4, 8-27, 8-28, 9-1, 9-2, 9-3, 9-4, 9-7, 9-10, 9-11, 9-12, and 9-13:

Surface Water and Groundwater:

As described in Section 2.5 of the Draft EA, the project involves the construction of a less than 0.5-mile-long CO_2 flowline to carry the compressed CO_2 to an injection site for deep geologic storage. The flowline would be located on previously disturbed Minnkota-owned property and has been routed to avoid sensitive surface and groundwater environments.

As described in Section 3.5.2.1 of the Draft EA, project construction would require the development of a Stormwater Pollution Prevention Plan (SWPPP), which would contain site-specific measures to avoid and minimize erosion and sediment transport to surface waters wetlands, and riparian zones, as well as measures to contain and clean up accidental petrochemical spills. Potential impacts to Nelson Lake and Square Butte Creek would be mitigated using site-specific measures and best practices identified in the SWPPP and associated National Pollutant Discharge Elimination System (NPDES) permit (Clean Water Act Section 402), designed for water quality protection and to ensure water quality standards of nearby surface waters are not exceeded. If necessary, the current MRY NPDES permits would be amended as needed to address any operational changes Project Tundra would cause. However, as designed, Project Tundra would operate as a "zero liquid discharge" facility. All regulatory agencies would be consulted prior to implementation of future changes.

Hazardous materials and wastes would be stored and disposed of in accordance with standard operating health and safety procedures of the project sponsor, which will be at least as stringent as those of the site owner Minnkota. Project areas temporarily affected by construction (i.e., not retained for facility operation) would be restored to original conditions.

As described in Section 3.5.1.1.1 of the Draft EA, it is not anticipated that a Clean Water Act Section 404 permit would be required from the U.S. Army Corps of Engineers because project construction and operation would not result in the placement of dredged or fill material into Waters of the United States. Therefore, it is not anticipated that a water quality certification will be required.

The project does overlay a non-community well protection area. Care will be taken to avoid spills via the SWPPP and associated state permit. Spill reporting will follow the SWPPP reporting requirements of 40 CFR 110, 40 CFR 117, and 40 CFR 302, the reporting requirements found in North Dakota Administrative Code (NDAC) 33.1-16-02.1, and any release which meets any reporting requirement in accordance with Part IV(A)(7).

Water Appropriations:

Regarding the proposed water appropriation from the Missouri River, the North Dakota State Water Commission (ND Water Commission) has approved the 15,000-acre-feet water appropriation as described in Section 2.5.2.1 of the Draft EA. The permitting authority has the responsibility of determining whether the proposed amount of additional water is attainable or not. The agency's review of the permit application included a detailed analysis of the potential effect on existing water appropriations, which determined that approval of the requested appropriation was acceptable.

In an October 2023 follow-up query, the ND Water Commission confirmed that permitted drinking water appropriations from the Missouri River, Lake Sakakawea, and Lake Oahe total 201,041 acre-feet of consumptive use (or 65,509,432,046 gallons). This number was determined based on municipal appropriations. Note that this value is the water allocated, but allocations may not be developed or currently in use. A large percentage of Missouri River appropriations are authorized for multiple uses associated with the original Garrison Diversion Unit Project and derived water permits associated with the Garrison Diversion Reformulation Act of 1986, Northern Area Water Supply Project, and the Red River Valley Water Supply Project. Multiple uses comprise 3,145,000 acre-feet of consumptive use (or 1,024,801,200,000 gallons).

The mean daily flow of the Missouri River at Lake Sakakawea during water years 1955 through 2019 is estimated to be 9,518,363 gallons per minute, 21,207 cubic feet per second, or 42,179 acre-feet per day. The mean annual discharge over the same period, water years 1955 through 2019, is estimated to be 15,363,704 acre-feet. The 15,000 acre-feet of water requested for the project is 0.10 percent of the mean annual discharge recorded at Garrison Dam and the requested withdrawal rate of 13,480 gallons per minute, or 30.0 cubic feet per second, is 0.14 percent of the mean daily discharge rate.

Given the remaining water availability via mean daily flow data and mean annual discharge data, the proposed project does not represent a significant change to daily flow or annual discharge. Therefore, the project would not preclude other water users from exercising their right to appropriate water, subject to ND Water Commission permitting requirements and regulatory requirements at NDAC Title 89-03 and North Dakota Century Code 61-04. It is the responsibility of state agencies to regulate water withdrawals and initiate conditions for approval, which would include any future consideration of potential worsening drought conditions in the region, if applicable.

Summary Comment 14: Solid and Hazardous Waste/Spill Response

Synopsis:

DOE received comments regarding proper management and transport of solid and hazardous wastes and the development of a spill response plan, which emphasizes rapid containment/cleanup of spills and surveillance and monitoring for early detection of leaks. Additionally, one commenter inquired about the presence of a potential historical underground storage tank (UST) within the MRY.

Response to Comments 9-3, 9-6, 9-8, and 9-9:

As described in Section 3.8.1 of the Draft EA, all waste, both hazardous and non-hazardous, would be managed pursuant to federal and state environmental regulations. Stormwater generated from the construction site would be managed as specified in the project SWPPP.

All new waste streams would be profiled and either sent offsite to be disposed of by properly licensed disposal providers or may be contracted for disposal with Minnkota in the MRY landfill in accordance with the landfill’s existing permits. Hazardous waste would not be expected from any of the new waste streams, but if a waste was determined to be hazardous it would be disposed of in accordance with state and federal regulations.

As described above and in Section 3.5.2.1 of the Draft EA, the project sponsors would develop a SWPPP prior to project construction. In addition to containing site-specific measures to avoid and minimize erosion and sediment transport to surface waters, the SWPPP would also include measures to contain and clean up accidental petrochemical spills. Spill prevention and containment measures would be considered during project engineering design to prevent pollutant discharges to the surface, and all attempts would be made to prevent contamination of water from construction activities, such as fuel spillage, lubricants, and chemicals, by following safe handling and storage procedures. Stormwater runoff would be managed to minimize sediment and silt movement, and other potential pollutants. In addition to developing a site-specific SWPPP, a site-specific Spill Prevention, Control, and Countermeasure Plan (SPCC Plan) is maintained for the MRY facility. If applicable, one will also be developed for Project Tundra as a separate facility. Additional spill response measures would be included as part of the standard operational environmental, health, and safety planning.

Regarding the inquiry into a potential historical UST at MRY, Minnkota removed the North Dakota Department of Environmental Quality (NDDEQ) UST permit #046 on May 18, 2021. No UST is associated with the project.

Summary Comment 15: Reliability and Safety

Synopsis:

One commenter recommended consideration of resiliency and emergency remediation and response plan be made available for public consideration.

Response to Comment 7-9:

The inclusion of an Emergency Remediation and Response Plan (ERRP) is beyond the scope of this EA; however, the preliminary ERRP is publicly readily available on the North Dakota Industrial Commission website for Class VI permits at https://www.dmr.nd.gov/dmr/oilgas. Updates and additions to this plan may be made during final design and construction.

The proposed project is located in North Dakota, which is a state of extreme weather conditions. One of the benefits of the proposed project's location is that demonstrating technology and process in a location with extreme weather patterns will require the team to account for these variable extremes in design and engineering.

North Dakota	Maximum Temperature	121°F
North Dakota	Minimum Temperature	-60°F
North Dakota	24-Hour Precipitation	8.1 in.
North Dakota	24-Hour Snowfall	27 in.
North Dakota	Snow Depth	65 in.

K.4.6 Socioeconomics and Environmental Justice

DOE received comments related to the socioeconomic and environmental justice analysis provided in Section 3.13 of the Draft EA. Comments relate to the validity of the assessment of economic benefits and the need for more in-depth analysis of impacts to environmental justice populations.

Theme	Revised Draft EA Location	Sub-Themes
Socioeconomics and Environmental Justice	Sections 3.11 and 4.11	Summary Comment 16: Socioeconomic Benefits Summary Comment 17: Environmental Justice

Summary Comment 16: Socioeconomic Benefits

Synopsis:

Commenters encouraged DOE to include consideration of impact to consumer rates for electricity due to "retrofitting" impacts on the MRY's operating performance.

Response to Comments 1-15, 5-20, and 5-21:

As an initial matter, DOE observes that the project is a stand-alone facility adjacent to MRY. It is not a "retrofit." The project is owned by a separate owner, who bears the operating costs and maintenance of the CCS facility. Consequently, there is no direct, project-specific impact caused by the project on ratepayers, as suggested by the commenter.

With respect to indirect rate impacts, the CCS unit is structured physically and commercially to have no impact on the dispatch of MRY and therefore would not have impact on the dispatch characteristics or the cost to operate the power plant. For further information about MRY rates in general, DOE directs the commenter to Minnkota's most recent 2022 Integrated Resource Plan (IRP) filed with the Minnesota Public Utility Commission to provide additional information and data on resource planning and adequacy. Minnkota's utility rates are discussed throughout the IRP**,** which also includes a discussion of its member-consumers participation in the planning process and potential impacts to member rates.

Summary Comment 17: Environmental Justice

Synopsis:

One commenter suggested additional discussion of environmental justice and socioeconomics of the proposed project be included in the EA and questioned the data used to establish environmental justice thresholds.

Response to Comments 5-15, 5-17, 5-18, 5-22, 5-23, and 5-24:

DOE wishes to further clarify the potential environmental justice and economic impact of building the project to the immediate community and the state of North Dakota. The EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies."[1]

The proposed project includes the construction and operation of a CCS facility adjacent to the MRY. Environmental justice considerations include the potential impact of the CCS operation on the electricity

[1] https://www.epa.gov/environmentaljustice

generated and transmitted from the MRY. The MRY is owned by Minnkota Power Cooperative, which is a not-for-profit regional generation and transmission cooperative, that provides about 1,300 MWs of wholesale power capacity (generated from 13 resources) to 11 member-owner distribution cooperatives in eastern North Dakota and northwestern Minnesota (see Figure 1). These members serve approximately 149,000 consumer accounts in a 34,500 square-mile area, including rural homes, farms, schools, and businesses. Minnkota also serves as the operating agent for the Northern Municipal Power Agency (NMPA), which supplies the electric needs of 12 associated municipalities that serve approximately 16,000 consumer accounts.

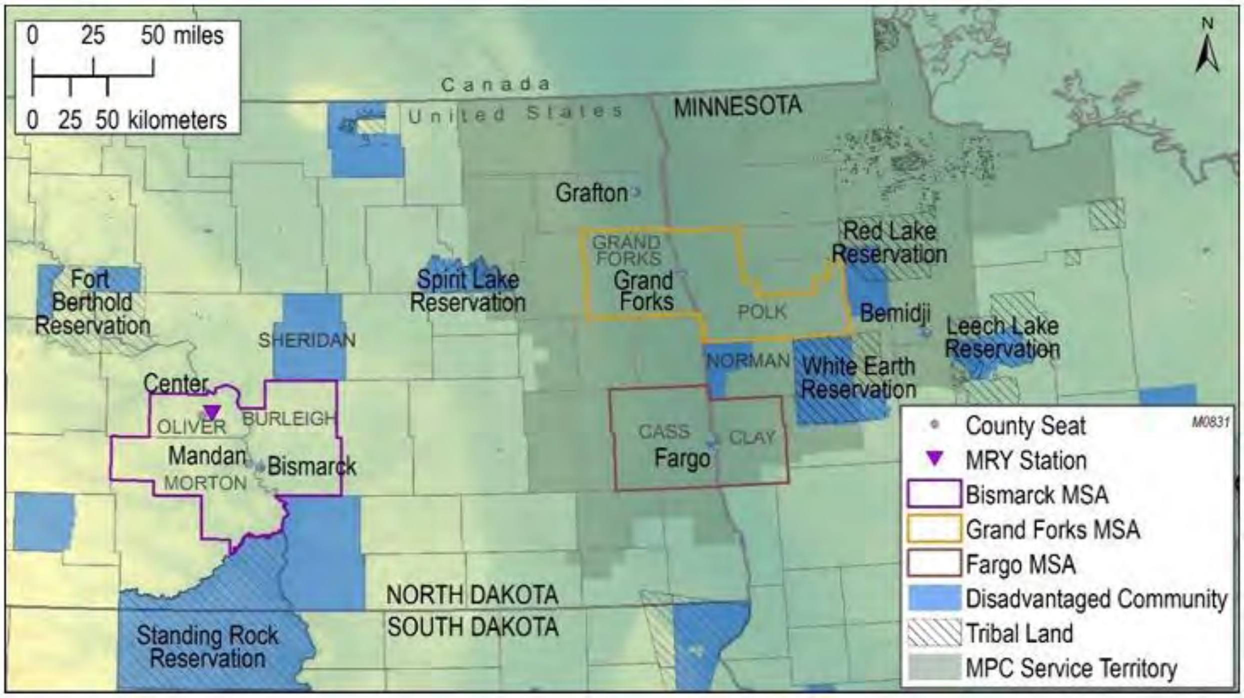


Figure 1: Minnkota's service territory and impacted disadvantaged communities, tribal lands, and Metropolitan Statistical Areas (MSA).

These distribution and municipal cooperatives have end-use consumers who are also stakeholders, and it is the mission of Minnkota to meet the electricity needs of those end-use stakeholders. For the Minnkota service area members, access to safe, reliable, affordable, and environmentally responsible electricity is vitally important to the region's continued success, quality of life, and regional security. Minnkota has worked for more than 80 years to provide the electricity that supports and unites rural communities across eastern North Dakota and northwestern Minnesota (Figure 1).

The geographical areas investigated include the Burleigh–Morton–Oliver County MSA, Tribal Nations within Minnkota's service territory, and the service territory as a whole (Figure 1). These areas were assessed through the DOE's Disadvantaged Communities Reporter. Additional data were referenced from The Council on Environmental Quality's Climate and Economic Justice Screening Tool (CJEST) and the EPA's EJScreen tool. These tools detail potential burdens within affected communities. To be considered a disadvantaged community, a census tract must rank in the 80th percentile of the cumulative sum of the 36 burden indicators and have at least 30% of households classified as low-income. Additionally, federally recognized tribal lands are categorized as disadvantaged communities in accordance with the Office of Management and Budget's "common conditions" definition of a community.

Energy democracy is one of the DOE's Justice40 policy priorities. Minnkota is owned by 11 member-owner distribution cooperatives, each of which oversees a portion of Minnkota's service area. Membership is open to anyone who can use its services and is willing to accept the responsibilities of membership. Cooperatives are run democratically. Minnkota's generation portfolio also includes wind and hydroelectric; member-consumers can choose how much of their energy is produced by renewable resources. Minnkota has also supported member-cooperatives pursuing independent solar projects. Democratic Member Control is one of the seven foundational principles on which all cooperatives operate. The proposed project will reduce carbon emissions from a base-load generating resource. These steps support the DOE Justice40 policy priority of increased parity in clean energy technology access and adoption in disadvantaged communities. This project presents opportunities for an increase in clean energy creation and contracting for minority or disadvantaged businesses in disadvantaged communities.

The project sponsors engaged the Bank of North Dakota (BND) and FTI Consulting to produce a study on the economic impact of the proposed project related to job creation. This process used Regional Economic Modeling, Inc. (REMI) software to gauge the impact of the project on associated positions within the impacted territory. REMI grew from the University of Massachusetts and has had its underlying model structure and equations published in the American Economic Review. For the proposed project, the REMI software was used as an initial analysis to determine the direct jobs and investments needed to develop and construct the world's largest CO_2 CCS plant at the MRY facility.

The REMI software results show the "direct" effect of jobs or expenditures and their related "indirect" effect on industrial supply chains and "induced" effects on consumer expenditures. This analysis included labor market quality, job availability, wages relative to the cost of living, domestic migration, and demand for housing. Using this model and timeline inputs, it was found that during construction, the total number of jobs peaks at 1,175 before stabilizing at around 250 jobs during operations.

During the construction phases, constructions jobs make up over half of the impacted jobs. Government, Retail, Healthcare, Hotels, Real Estate, and Personal, Professional, and Business Services all show marked increases. During later operations phases, these position types hold, with the addition of Utilities. See Figure 2.

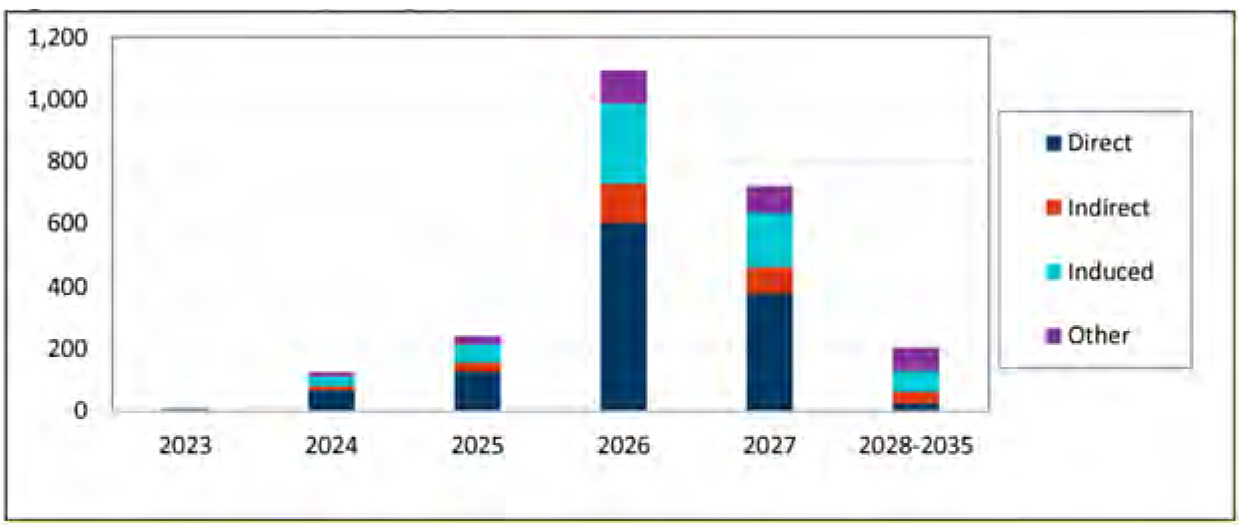


Figure 2: Jobs created by Category

The project is also likely to increase clean energy jobs, job pipelines, and job training for individuals from disadvantaged communities, another DOE Justice40 policy priority. The primary energy and environmental justice benefits of this project are twofold: a steep reduction in emissions and the creation of clean energy jobs. The latter has the most potential of direct benefit to disadvantaged communities.

The construction of the capture plant will require approximately 400 to 600 science, technology, and engineering and construction professionals, in addition to approximately 25 permanent operations positions needed from commissioning throughout the life of the project. The REMI data reinforces and agrees with these estimates. Project ownership will ensure that the project attracts and retains a highly skilled and diverse workforce by offering highly competitive compensation that will meet or exceed Davis–Bacon wage and benefits requirements. This is a fundamental imperative, given the especially competitive high-wage labor market; North Dakota is ranked second nationally for its low unemployment rate: 1.9% in September 2023, and per capita income is about 10% above the national average. Prevailing North Dakota wages for the major job categories to be created by the project are outlined in Table K-4. Project ownership will ensure that the project's wage and benefits requirements will be applied consistently for all workers involved in the construction and operations of the project with clear and consistent requirements for all subcontractors.

Table K-4. May 2021 State Occupational Employment and Wage Estimates, North Dakota

Occupation Title	Employment	Employment per 1000 Jobs	Median Hourly Wage	Mean Hourly Wage	Annual Mean Wage
Architecture and Engineering Occupations	5270	13.34	$37.61	$39.92	$83,020
Project Management Specialists	1490	3.762	$37.38	$40.06	$83,320
Construction and Extraction Occupations	28,000	70.87	$23.63	$27.69	$57,600
Installation, Maintenance, and Repair Occupations	21,120	53.47	$23.65	$27.35	$56,880

One commenter expressed concerns that DOE should conduct a comprehensive analysis of potential project air quality impacts on Center, North Dakota due to concerns regarding pollutants (e.g., fly ash and PM) from the coal-fired MRY facility. Emissions from the proposed CCS project and the existing MRY coal-fired power plant emissions were modeled as part of the NDDEQ air permit application process. DOE has included the current background air quality and the projected emissions changes due to operation of the proposed CCS project for MRY in Section 3.2.1.1 of the revised Draft EA. The project's Air Permit to Construct, Air Quality Emissions Analysis, and Air Quality Impact Analysis are included in Appendix J to the revised Draft EA.

As part of the air permitting process, a 30-day public comment period for the proposed air permit began on September 21, 2023, and ended on October 21, 2023. On October 19, 2023, NDDEQ hosted an air permit public hearing at the Betty Hagel Memorial Civic Center in Center, North Dakota to obtain feedback on the air permit. Approximately 50 people attended the meeting. Two people spoke, both in support of the project. NDDEQ staff concluded that the project would comply with all applicable air pollution control rules and is protective of human health and the environment and, on December 29, 2023, issued Air Permit to Construct No. ACP-18194 v1.0 (see Appendix J of the revised Draft EA). According to CJEST, Center is not considered a community that is economically disadvantaged or overburdened by pollution. Therefore, it is not anticipated that Center would experience high adverse health or environmental effects from air emissions associated with the MRY facility or project.

See also the response to Summary Comment 25.

K.4.7 Social Cost of Greenhouse Gases (SC-GHG)

DOE received several comments related to greenhouse gases (GHGs) and climate change, specifically regarding the SC-GHG analysis and the LCA.

Theme	Revised Draft EA Location	Sub-Themes
Social Cost of Greenhouse Gases (SC-GHG)	Sections 3.19 and 4.19	Summary Comment 18: SC-GHG Methodology Summary Comment 19: SC-GHG Equivalencies

Summary Comment 18: SC-GHG Methodology

Synopsis:

These comments recommend providing additional clarity to the scope of emissions included in the analysis and clearly defining the no-build alternative that is being represented in the SC-GHG analysis. Further, it was recommended the 95th percentile of estimates based on the 3 percent discount rate be included within this analysis.

Response to Comments 7-5, 7-6, 7-9, and 8-14:

The purpose of the SC-GHG is to show estimates, in dollars, of the economic damages that would result from emitting one additional ton of a GHG (CO_2, nitrous oxide [N_2O], methane [CH_4]) into the atmosphere each year. The "social cost" puts the effects of climate change into economic terms to help policymakers and decisionmakers understand the economic impacts of decisions that would increase or decrease emissions. For this analysis, two scenarios were represented: a proposed action alternative (build scenario), where the proposed CCS is constructed and operated, and a no-action alternative (no-build scenario) where the CCS is not constructed. The SC-GHG utilizes the expected emissions of MRY with and without the construction of the CCS as a means of comparison. For more information on the selection of the no-action alternative, reference Summary Comments 7 and 8.

The SC-GHG analysis uses future projected fuel consumption at the MRY plant for the years 2028 through 2048, as well as the expected carbon sequestration in those years. Projected annual fuel consumption at MRY was determined to be a more realistic estimate of future operations as opposed to MRY's Potential-To-Emit (PTE). PTEs are based on units running at maximum capacity and inform a worst-case scenario of expected emission, which is often an unrealistic representation of actual annual operations. Thus, the annual use of the fuel consumption projections in this analysis allows for a more realistic representation of the SC-GHG. Upstream and downstream emissions are not included in this analysis because the scope of the proposed project is limited to the carbon capture system and sequestration system which does not affect the upstream (coal/fuel oil extraction) activities or the downstream (transmission and distribution of electricity) activities.

The SC-GHG analysis has been updated to utilize the DOE standardized SC-GHG workbook. The workbook (and the analysis presented in the Draft EA document) utilize the Interagency Working Group Technical Support Document[2] that sets interim estimates of SC-CO_2, SC-N_2O, SC-CH_4, known cumulatively as SC-GHG. The interim estimates have been developed using the average of three different annual discount rates: 2.5%, 3%, and 5%. Additionally, an estimate is provided for the 95th percentile of an

[2] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. 2021.

applied 3% discount rate for future economic effects. This is a low probability but high damage scenario that represents an upper bound of damages within the 3% discount rate model. The updated SC-GHG results rounded to the nearest million value are present below in Table K-5.

Table K-5. Present Value (in Base Year 2028) of Estimated SC-GHG Comparison of Proposed Action and No-Action Scenarios (2020$, Rounded)

Discount Rate	5%	3%	2.5%	3%
Statistic	Average	Average	Average	95th Percentile
No-Action	$1,717,000,000	$6,106,000,000	$9,071,000,000	$18,629,000,000
Proposed Action	$393,000,000	$1,391,000,000	$2,066,000,000	$4,231,000,000
Difference	**-$1,324,000,000**	**-$4,715,000,000**	**-$7,005,000,000**	**-$14,398,000,000**

The updates to the SC-GHG analysis do not change the DOE's conclusion that the proposed CCS is projected to reduce total GHG emissions and associated social costs compared to the no-action alternative. For discount rates high to low over the analysis lifespan, the reduction in the SC-GHG was calculated to be approximately -$1.3, -$4.7, and -$7.0 billion in 2020 dollars if the proposed project is constructed and operational. For the 95th percentile of an applied 3% discount rate, the reduction in the SC-GHG that is attributed to the proposed project is approximately -$14 billion.

Summary Comment 19: SC-GHG Equivalencies

Synopsis:

The EPA recommends providing the GHG emissions in carbon dioxide equivalents (CO_2e) and translating emissions in equivalencies that are more easily understood to the public. Additional recommendations include additional discussion of the GHG emissions in respect to reduction goals and ensuring that appropriate context has been provided to verify the EA meets the requirement of "disclosing and providing appropriate context for GHG emissions".

Response to Comments 7-5, 7-6, 7-8, 8-14, and 10-1:

The Draft EA provided a SC-GHG analysis which follows the outline set by the Council on Environmental Quality to "*provide additional context for GHG emissions including through the use of best available SC-GHG estimates, to translate climate impacts into a more accessible metric of dollars…*"[3]. The discussion regarding the revised SC-GHG analysis is available in Summary Comment 18.

Annual GHG emissions (CO_2, CH_4, and N_2O) were estimated to calculate the SC-GHG. Refer to the discussion regarding the revised SC-GHG analysis in Summary Comment 18 for methodology. To satisfy the request for additional context regarding the expected GHG emissions and the subsequent reduction that is expected due to the construction and operation of the CCS, the annual GHG emissions were converted into a representative CO_2e value by multiplying each GHG by its respective 100-year Global Warming Potential[4] (GWP). GWP are factors applied to each individual GHG to convert their emissions to their potency to affect global warming compared to that of CO_2. Representative equivalencies are calculated utilizing methodology outlined by the EPA Greenhouse Gas Equivalencies Calculator References[5]. Please

[3] https://www.federalregister.gov/d/2023-00158 published January 09, 2023.
[4] Table A-1 to Subpart A of Part 98, Title 40, https://www.ecfr.gov/current/title-40/appendix-Table%20A-1
[5] https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

note that the presented annual CO_2e emissions and equivalencies are estimates based on projected fuel use at MRY and expected CO_2 sequestration.

The annual CO_2e reduction value stays constant on an annual basis. This assumes that 11,793 metric tons of CO_2 will be processed daily, and that all CO_2 will be sourced from the MRY Plant. The overall annual reduction value is equivalent to approximately 4 million metric tons of CO_2e annually. Utilizing EPA emission factors for GHG emissions from gasoline-powered passenger vehicles, the reduction in CO_2e from implementing and operating the CCS project is equivalent to taking just under 950,000 cars off the road annually. For another reference, the CCS project is equivalent to the CO_2e sequestration potential of 3,600,570 acres of U.S. forests in one year, assuming one acre of average U.S. forests sequesters 0.84 metric tons of CO_2 per year.

K.4.8 Initial Life Cycle Analysis (LCA)

DOE received several comments related to GHGs and climate change, specifically regarding the Initial LCA presented in Appendix E of the Draft EA.

Theme	Revised Draft EA Location	Sub-Themes
Initial Life Cycle Analysis (LCA)	Sections 2.5.6, 3.3, and Appendix E	Summary Comment 20: Initial LCA Approach Summary Comment 21: Initial LCA Functional Unit Summary Comment 22: Sulfur Hexafluoride (SF_6) Summary Comment 23: Initial LCA Methodology and Assumptions Summary Comment 24: Initial LCA Conclusions Summary Comment 25: Air Emissions and Modeling Summary Comment 26: Presumption of Zero Measurable Leakage

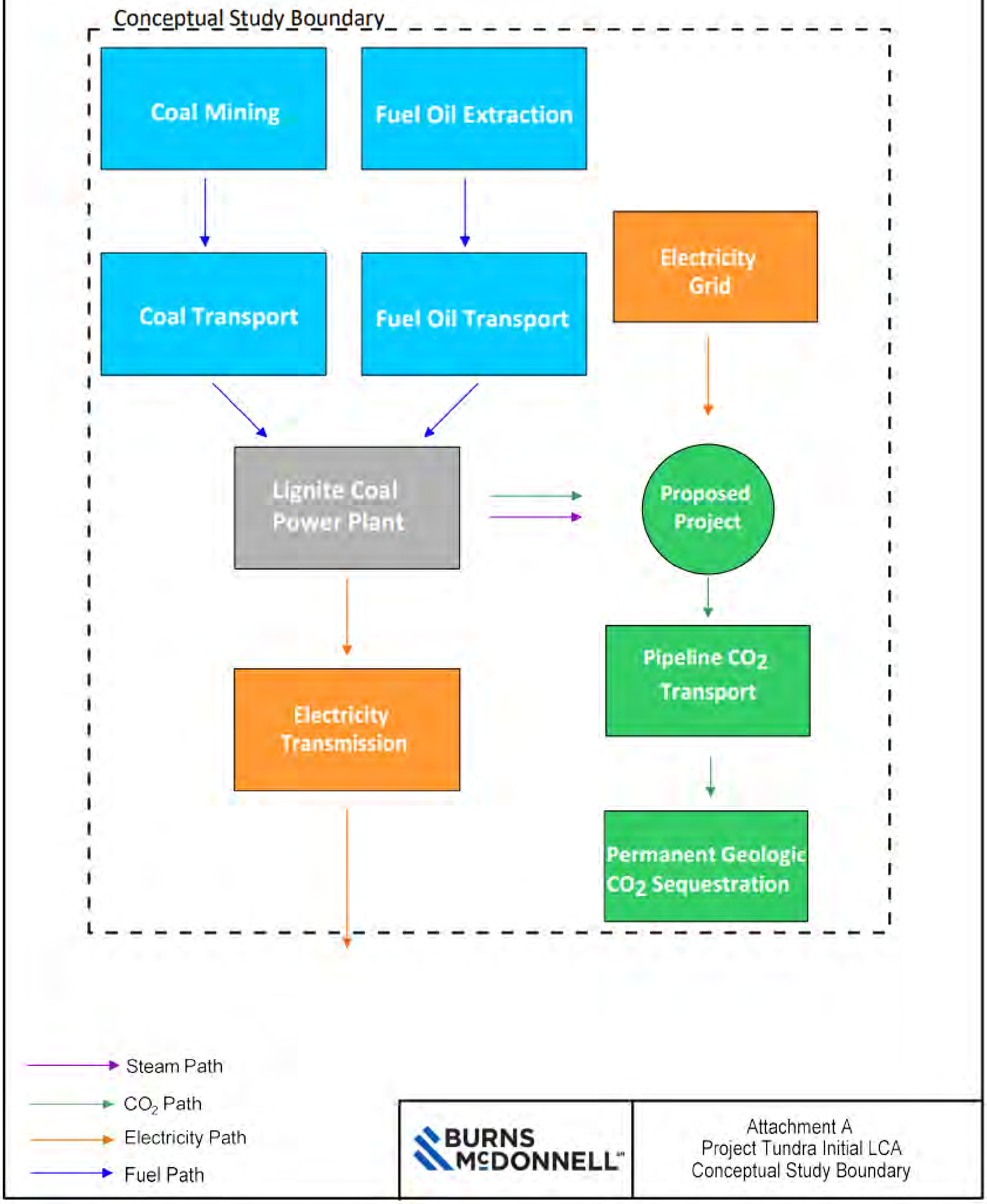
Summary Comment 20: Initial LCA Scope

Synopsis:

There were multiple comments on the scope of the LCA posing the following concerns: (1) the inclusion of electricity transmission and distribution, as well as the omission of (2) non-GHG impacts and a sensitivity analysis, (3) emission contribution sources such as reservoir leakage, (4) the emissions from the carbon capture plant operation including parasitic load, (5) CO_2 transportation (pipeline fugitive emissions), and (6) construction and manufacturing.

Response to Comments 1-2, 1-4, 1-8, 1-9, 1-12, 1-13, 1-14, and 7-7:

An Initial Life Cycle Assessment, which is required for projects applying for funding under DOE FOA DE-FOA-00002962, is a screening-level assessment of GHGs only. Appendix J of FOA 2962 states that the scope of the Initial LCA is “cradle to delivered electricity, inclusive of transmission of the electricity to the final customer,” and a “contribution analysis showing at a minimum the impacts from fuel extraction and delivery, plant direct emissions, and CO_2 transport and storage.” The Initial LCA Conceptual Study Boundary diagram printed here to assist readers, shows the scope of the Initial LCA in diagram format.



Attachment A
Project Tundra Initial LCA
Conceptual Study Boundary

This diagram shows the scope of the Initial LCA to include GHG emissions for mining/extraction of coal and fuel oil, transport of the coal and fuel oil, use of the fossil fuels at MRY, the operation of the proposed CCS project, and the transmission of electricity. The proposed project and associated activities are shown in the green boxes, GHG emissions associated with these activities are the direct[6] emissions that would occur because of the project moving forward. Indirect emissions, all other emission activities identified within the analysis boundary, are considered consequences of the proposed project operating but are ultimately not controlled or operated by the same entity as the proposed project. Therefore, the sequestration of CO_2 from flue gas is ultimately not expected to change the GHG emissions of any of the other upstream or downstream activities.

The largest emissions of GHG originate from sources categorized as Upstream Fuel Extraction and Delivery (inclusive of Coal Electricity Production) and Electricity Transportation. These categories account for emission processes that are already in operation and are not dependent on the operation of the proposed facility. In other words, these sources of GHG already exist and will not be affected by the presence or absence of the proposed project. It should be noted that CO_2 emissions account for most of the GHG emissions for all categories except for Electricity Transportation. This is due to the comparatively large GWP value of sulfur hexafluoride (SF_6)[7], which is utilized in the transmission and distribution process. SF_6 is further explained in Summary Comment 22.

(1) As established above, the Initial LCA follows the guidance presented in FOA 2962, which specifies the scope of the Initial LCA to be cradle-to-delivered electricity. As such, electricity transmission is included in the Initial LCA. However, electricity distribution and its associated losses are not included in the scope of this analysis. This is noted explicitly in the footnotes under each table.

(2) The Initial LCA is defined for this purpose as a screening-level, GHG-only analysis. Non-GHG impacts and a sensitivity analysis are beyond the scope of a screening level analysis.

(3) For a discussion of reservoir leakage, see Summary Comment 26.

(4) For a discussion of the capture plant emissions, see Summary Comment 25.

(5) Contribution sources such as the carbon capture facility operations, pipeline fugitive emissions, and reservoir leakage (direct emissions) were considered and accounted for in this analysis. These are shown in Table K-7 under the "Proposed Project" and "Downstream" headings.

(6) Upon review, Energy consumption occurring at the carbon capture facility was determined to be within the scope of the analysis and is now incorporated in the revised analysis[8]. Construction and manufacturing of the proposed carbon capture facility was determined to be outside the scope of a "screening-level" analysis. Construction and manufacturing emissions are temporary in nature and, as such, they were excluded from the Initial LCA.

[6] Direct defined as GHG emissions from sources that are owned or controlled by the operating (and ultimately reporting) entity.
[7] Note: SF6 emission factor units and the Initial LCA functional units have been revised. This is further discussed in Summary Comments 21 and 22.
[8] Further discussion can be found in Summary Comment 23.

Summary Comment 21: Initial LCA Functional Unit

Synopsis:

As noted by commenters on the Initial LCA, the methodology of the analysis presented in the Draft EA follows the requirements as outlined in FOA 2962. Comments identify that the FOA LCA requires calculation of impacts per unit of delivered electricity (1 megawatt-hour [MWh] of electricity). In looking at the Initial LCA, a number of commenters misinterpreted the results of the Initial LCA and concluded that 3 kilograms (kg) of CO_2e emitted per kg of CO_2 sequestered meant that the project was emitting more CO_2 than it was capturing.

Response to Comments 1-1, 1-2, 1-5, 1-6, 1-8, 1-10, 1-11, 1-12, and 7-4:

DOE has reprinted the original table, with updates related to SF_6 (See Summary Comment 22 for a discussion of SF_6) and the inclusion of energy consumption. DOE's intent is to first clarify changes to the original table prior to converting it to different units. DOE has provided additional Initial LCA outputs in a standardized unit of MWh in order to provide the public with further details that better demonstrate the Initial LCA analysis and conclusions.

The comments identified that the Initial LCA failed to properly net out the sequestered CO_2 emissions and thus incorrectly overestimated the emissions resulting from the "build" scenario. As a result, the CO_2 emissions from the coal electricity plant upstream of the project are significantly reduced. Specifically, CO_2 emissions seen at the coal plant have been updated from 1.35 kg CO_2 to 0.43 kg CO_2. This value correctly accounts for the CO_2 captured, and therefore not emitted to the atmosphere, when the CO_2 capture plant is operating. This error has been corrected and revised tables have been provided below and in Appendix E.

Table K-6. Revised Initial LCA (kg of Emissions per kg CO_2 Sequestered)

Emission Source	kg of Emissions per kg CO_2 Sequestered				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	***7.52×10^{-04}***	***5.94×10^{-06}***	***8.09×10^{-04}***	-	***3.16×10^{-02}***
FO Extraction	8.87×10^{-05}	2.68×10^{-09}	4.76×10^{-07}	-	1.07×10^{-04}
Coal Transportation	***9.35×10^{-04}***	***3.79×10^{-08}***	***7.59×10^{-09}***	-	***9.47×10^{-04}***
FO Transportation	5.53×10^{-07}	1.42×10^{-11}	1.11×10^{-11}	-	5.58×10^{-07}
Coal Electricity Plant	***0.34***	2.15×10^{-05}	1.47×10^{-05}	-	***0.34***
Proposed Project					
CO_2 Capture Plant	0.01	-	-	-	0.01
Electricity Consumption[a]	***0.04***	***1.81×10^{-06}***	***1.24×10^{-06}***	***--***	***0.04***
Downstream					
CO_2 transportation	8.58×10^{-05}	-	-	-	8.58×10^{-05}
CO_2 storage[b]	-		-	-	-
Electricity Transmission[c]	-	-	-	***9.25×10^{-08}***	***2.17×10^{-03}***
TOTAL LCA	***0.39***	***2.93×10^{-05}***	***8.26×10^{-04}***	***9.25×10^{-08}***	***0.43***

[a] Electricity Consumption emission source is a new categories added into the revised Initial LCA.
[b] Assumes no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
[c] Does not account for electricity losses from transmission and distribution.
**Bolded Italicized* numerical values are called out as changes from the original analysis.

The revised initial LCA shows that 0.43 kg of CO_2e is emitted to the atmosphere for every 1 kg of permanently sequestered CO_2. However, it is important to note that the initial LCA includes indirect emission sources including upstream and downstream emissions that are created from electricity production that is not dependent on the presence (or absence) of the proposed project. The revised Table K-6 confirms that the proposed project will not create CO_2 emissions more than the emissions it is designed to prevent from being emitted from the atmosphere.

The functional unit in the Initial LCA was reconfigured to present results in terms of kg emissions per 1 MWh electricity produced. Below are the updated Proposed Action (Table K-7) and No-Action (Table K-8) Initial LCA summary tables. Refer to Appendix E for the Initial LCA Analysis.

Table K-7. Proposed Action, Initial LCA Results Normalized to 1 MWh

Emissions Source	kg of Emissions per MWh				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	0.79	0.01	0.85	-	33.27
FO Extraction	0.09	6.25×10^{-03}	5.00×10^{-04}	-	0.11
Coal Transportation	0.98	2.81×10^{-06}	7.98×10^{-06}	-	1.00
FO Transportation	5.81×10^{-04}	1.50×10^{-08}	1.16×10^{-08}	-	5.86×10^{-04}
Coal Electricity Plant	352.34	0.02	0.02	-	360
Proposed Project					
CO_2 Capture Plant	8.56	-	-	-	8.56
Electricity Consumption	49.90	1.92×10^{-03}	1.32×10^{-03}	--	50.52
Downstream					
CO_2 Transportation	0.09	-	-	-	0.09
CO_2 Storage*	-	-	-	-	-
Electricity Transmission**	-	-	-	7.85×10^{-05}	1.84
TOTAL LCA	412.76	0.03	0.87	7.85×10^{-05}	455

*Assumes no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.

**Does not account for electricity losses from transmission and distribution.

Table K-7 shows that 455 kg of CO_2e are emitted for every MWh at the upstream coal electricity production plant when the CCS project is in place. The scope of the LCA, as discussed in Summary Comment 20, includes sources of emissions which will remain unchanged by the presence or absence of the project. Therefore, the values related to uncontrolled CO_2e emissions are necessary to understand the impact of the project.

Table K-8. No-Action Alternative, Initial LCA Results Normalized to 1 MWh.

Emissions Source	kg of Emissions per MWh				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	0.64	5.05×10^{-03}	0.69	-	26.89
FO Extraction	0.08	2.27×10^{-06}	4.04×10^{-04}	-	0.09
Coal Transportation	0.79	3.22×10^{-05}	6.45×10^{-06}	-	0.80
FO Transportation	4.70×10^{-04}	1.21×10^{-08}	9.40×10^{-09}	-	4.74×10^{-04}
Coal Electricity Plant	1,134	0.02	0.01	-	1,140
Downstream	0.64	5.05×10^{-03}	0.69	-	
Electricity Transmission	-	-	-	7.85×10^{-05}	1.84
TOTAL LCA	1,136	0.02	0.70	7.85×10^{-05}	1,170

*Assumes no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
**Does not account for electricity losses from transmission and distribution.

Table K-8 shows that <u>without the CCS project</u>, 1,170 kg of CO_2e is emitted for each MWh. The net impact of the project is found by subtracting the controlled emission numbers from the uncontrolled emissions, resulting in the <u>net capture and permanent storage of 751 kg CO_2e/MWh.</u> Table K-9 provides a comparison of the change in CO_2e for the No-Action and Proposed Action scenarios.

Table K-9. No-Action and Proposed Action Comparison, Initial LCA Results Normalized to 1 MWh

Emission Source	kg of CO_2e Emissions per MWh		
	No Action	Proposed Action	Percent Change *
Upstream			
Coal Mining	26.89	33.27	24%
FO Extraction	0.09	0.11	24%
Coal Transportation	0.80	1.00	24%
FO Transportation	4.73×10^{-04}	5.86×10^{-04}	24%**
Coal Electricity Plant	1,140	360	-68%***
Proposed Project			
CO_2 Capture Plant	NA	8.56	NA
Electricity Consumption	NA	50.52	NA
Downstream			
CO_2 transportation	NA	0.09	NA
CO_2 storage	-	-	-
Electricity Transmission	1.84	1.84	0%
TOTAL LCA	1,170	455	-61%

* Percent change, by definition, cannot be calculated for scenarios where the initial value is zero; such is the case in terms of the CO_2 capture plant, energy consumption, transportation, and storage.
** The heat input at MRY does not change as a result of the CO_2 plant operating.
*** The capture unit has a s 95% capture efficiency of flue gas that is <u>treated</u> by the system. For a complete discussion of the capture percentage, see Summary Comment 9.

It is important to understand the context for the results of the Initial LCA for Project Tundra. The Initial LCA analysis is a standardized methodology the DOE has created to estimate "cradle to transmission" emissions from the mining of the coal through delivery of the electricity through the transmission grid. This standardized methodology is instructive for comparison between projects. *It does not provide a forecast of the actual quantity of GHG emissions that will be emitted* because the standardized Initial LCA must be conducted on an assumed single operating point for both the generating unit and the CCS system. In actual practice, during most of the hours of the year, neither the generating station nor the CCS will be operating at the level of that assumed point. Instead, the generating units will be responding to an infinite set of grid and operating conditions.

Summary Comment 22: Sulfur Hexafluoride (SF_6)

Synopsis:

One commenter questioned the SF_6 emission factor as utilized in the Initial LCA as well as the supposed erroneous use of the SF_6 GWP within the same calculation.

Response to Comment 1-4:

After further investigation, DOE determined that FOA 2962 Appendix J has a clerical error labeling the emission factor for SF_6 as "7.87x10^{-05} kg SF_6 emissions per kg CO_2 stored". DOE confirmed that this number was misprinted and should have instead read "7.87x10^{-05} kg SF_6 emissions per MWh." This is a standardized emission factor utilized by the DOE to represent SF_6 emissions during electricity transmission. However, to present results in terms of CO_2e emissions, this value must be multiplied by the SF_6 100-year horizon GWP (GWP-100) of 23,500. The application of the GWP was entirely correct in the Initial LCA; however, the tables had to be updated to correct the error in units from FOA 2962. The emission factor unit's correction was made throughout the analysis and is reflected in the results presented in Summary Comment 21. The table shows that the SF_6 emissions from transportation of electricity are 1.84 kg CO_2e/MWh.

Summary Comment 23: Initial LCA Methodology and Assumptions

Synopsis:

Commenters criticized the emissions identified in the LCA as a result of the "build" scenario, proposed expansion of the LCA, and further identified the electrical and steam requirements of the CCS were not properly accounted for in the LCA.

Response to Comments 1-6, 1-7, 1-14, 1-16, 5-18, 5-21, 5-22, 7-10, 7-11, 7-12, 8-15, and 8-16:

Actual projected operations at MRY as well as the compressor vendor estimates for start-up and shutdown annually were utilized for estimating emissions as identified in the "build" scenario. The emissions attributed to the carbon capture facility are a result of routine emissions and those associated with startup, shutdown, and potential malfunction of the system. The emission values presented in the Initial LCA analysis (38,338 short tons CO_2 per year) are based upon preliminary engineering estimates of the CO_2 compressor's annual activities, considering that there may be more of these startup/shutdown and malfunctions in the first couple of years of operation. In summary, emission rates presented in the Initial LCA are based upon engineering estimates available at the time of this analysis and reasonable assumptions as disclosed in Appendix E.

Energy use associated with the CCS has been incorporated in the revised Initial LCA project scope (Summary Comment 20) and has been incorporated as a new emission category. As an independent operation, the CCS system owners have chosen to purchase the electric and steam energy needed from Minnkota's electricity system. The steam and electricity offering to the CCS system is on terms and conditions similar to other large, unique loads on their system (e.g., computing and server centers). For the Initial LCA analysis, it is assumed that steam will be sourced directly from MRY following terms as agreed upon by the CCS system owners and Minnkota[9]. Similarly, it is assumed that the CCS system will receive electricity from the Minnkota electricity system (i.e., grid) that includes multiple generation sources.

Electricity and steam consumption occurring at the carbon capture plant has been incorporated into the analysis in order to fully account for inputs that reside within DOE's scope of a "screening-level GHG only" Initial LCA but several disclaimers are required to fully address this addition. First, Minnkota has disclosed that there are no operational changes upcoming at MRY or any of their existing generating stations as a result of the CCS project. Secondly, although steam is expected to be sourced directly from MRY, the heat rate at the plant will remain unchanged regardless of the operation (or lack of operation) of the CCS.

Recognizing that the proposed project will not impact the operation of Minnkota's generating facilities, the emissions from energy consumption have been incorporated into the Initial LCA analysis as indirect emission sources. Energy consumption is widely accepted as an indirect emission source as the emissions associated with the production of the electricity or steam occur physically at generating stations and not at the consumption site. In this case, the steam and electricity consumed by the CCS will be produced by Minnkota's generating system regardless of the existence of the CCS.

DOE has determined that further expansion of the Initial LCA scope goes beyond the requirements as outlined in FOA 2962 Appendix J.

Summary Comment 24: **Initial LCA Conclusions**

Synopsis:

A few commenters identified concerns over the Draft EA statement "The estimated 1,836 MW of electricity consumption and 600 gigajoules per day of thermal (steam) energy consumption for project operation would result in a similar reduction in net energy output of the MRY to serve Minnkota's load and would therefore result in minimal cumulative impact on GHG emissions from MRY."

Response to Comments 1-7, 7-10, 7-11, and 7-12, and 8-25:

The statement has been revised to correct for a typographical error in the value of steam consumption and unit of electricity consumption. The correct values are 1,836 MWh of power per day and 35,247 gigajoules per day. The 600 gigajoules value applied to a demonstration pilot plant by MHIA, the technology provider, and must be scaled up to represent the commercial scale capture unit. In any event, these values did not have a material impact on the LCA results because the values used for estimating emissions were from actual projected coal usage as well as the compressor vendor estimates for start-up and shutdown annually.

[9] Any referenced agreements are not finalized at this time and any terms aside from the stated assumptions are not relevant to the outcomes represented in the initial LCA.

Further, MW and MWh are different units and cannot be directly compared. The output of MRY, which is nameplated to 734 MW (gross), is equivalent to 17,616 MWh per day. To further provide clarification around the units of measure, DOE offers the following:

Units of demand and capacity

A watt (or kilowatt or megawatt) is a measure of power. Power is the *rate* of energy transfer, which is usually discussed as demand or capacity for energy.

Demand reflects the instantaneous amount of work required to perform the function desired (such as creating light or physical force, powering a microchip, etc.). Similarly, capacity reflects the instantaneous ability to provide energy required to do work (such as generator capability to provide electricity, transmission capability to transmit electricity, etc.). For example, a watt is defined as 1 joule per second, where you can think of a joule as one nicely measured packet of energy. Demand and capacity are commonly measured in the following units:

W = watt
kW = kilowatt
MW = megawatt
GW = gigawatt

To convert between these, you can use the following:

1 kW = 1,000 W
1 MW = 1,000 kW
1 GW = 1,000 MW

Units of energy/usage

Watt-hours (or kilowatt-hours or megawatt-hours) is just another way of measuring energy, it describes a unit of energy usage. A way to think about it is that watts measure the rate of energy demand (analogous to speed) while watt-hours measure the amount of energy used (distance traveled). The electric grid deals with large power levels and large energy transfers, so the electric industry expresses energy in MWh and kWh because that is more directly relevant to how energy is transferred and used. Energy or usage reflects demand or capacity multiplied by the amount of time that demand or capacity is in use.

For example, a 15-watt light bulb used for 2 hours creates 15 watts X 2 hours = 30 watt-hours of usage. Energy and usage are commonly measured in the following units:

Wh = watt-hour
kWh = kilowatt-hour
MWh = megawatt-hour
GWh = gigawatt-hour

The conversions between the units are:

1 kWh = 1,000 Wh
1 MWh = 1,000 kWh
1 GWh = 1,000 MWh

Another example would be a kWh is one kW of power flowing for one hour, which is 1,000 joules going by every second for one hour. Since there are 3,600 seconds in an hour, 1 kWh is therefore exactly the same as 3.6 megajoules.

Summary Comment 25: Air Emissions and Modeling

Synopsis:

A number of commenters discussed and proposed additional air emissions and air modeling considerations that DOE should consider.

Response to Comments 5-10, 5-11, 5-12, 5-14, 5-15, 5-16, 6-5, 7-10, 7-11, 7-13, 7-14, 7-15, 7-16, 7-17, 8-15, and 9-5:

DOE has included the current air emissions for MRY and the projected emissions changes due to operation of the proposed CCS project in Section 3.2 of the revised Draft EA.

MRY permitting activities are outside the scope of an EA analysis. Regardless, DOE understands that Minnkota as the owner and operator of MRY, in coordination with NDDEQ, is evaluating whether it is necessary to amend any aspect of the Title V permit to account for the separately owned, but geographically proximate CCS project facility. The owners of MRY have and will continue to evaluate compliance with all Clean Air Act regulations, including New Source Review provisions that could be implicated by the construction of the adjacent CCS project. We direct the commenters to the supporting documents for the Air Permit to Construct approved by the NDDEQ on December 29, 2023, which includes air quality modeling results that take into account emissions from the CCS project and MRY, fully and conservatively characterizing the emissions profile of the two facilities together even though they are separate sources.

Permitting is completed through NDDEQ. The project’s application and Air Permit to Construct, Air Quality Emissions Analysis and Air Quality Impact Analysis are included in Appendix J of the revised Draft EA. The air impact analyses and tables generated were performed based upon best engineering estimates and followed EPA and NDDEQ modeling guidelines under National Ambient Air Quality regulations. Any comments regarding the NDDEQ analyses are not within the purview of this EA or within the jurisdiction of DOE.

Finally, developing a construction equipment roster is premature and beyond the scope of an EA. A qualitative assessment of types and sources of minor and temporary impacts due to the presence of heavy equipment and the disturbance of soil is included in Section 3.2.2. As stated, air impacts related to construction would be minimized using the industry standard best management practices including, but not limited to the use of water sprays for fugitive dust suppression and the use of properly maintained construction equipment with emissions controls.

Summary Comment 26: Presumption of Zero Measurable Leakage

Synopsis:

DOE received comments regarding the reasonableness of the presumption of zero measurable leakage from the sequestration reservoir.

Response to Comments 1-9, 1-13, and 5-25:

The historical precedent of assuming 1% leakage from the storage reservoir has been propagated since the earliest days of the Intergovernmental Panel on Climate Change (IPCC) and was carried through subsequent

LCAs that evaluated systems with CCS. However, recent studies on storage permanence suggest that only under an assumed condition of a leaky wellbore would there be measurable amounts of CO_2 leakage, and further, there is a near-zero CO_2 leakage rate over a 100-year interval when plausible input values are used to represent potential leakage pathways like wellbores. Examining 1) the characteristics of the proposed project sequestration area of review (no wellbores intersect the CO_2 plume except for the injection wells; see Section 3 of Storage Facility Permit), 2) required design standards for Class VI wells, and 3) the presumption of proper construction and permitting as CO_2 injection or monitoring wells (following the requirements detailed in NDAC 43-05-01-11), and leak detection and monitoring (i.e., Distributed Temperature Sensor [DTS] and Distributed Acoustic Sensor [DAS] on the injection wells), <u>*a presumption of zero measurable leakage was determined to be a plausible and reasonable assumption*</u>.

INTENTIONALLY LEFT BLANK

K.5 PUBLIC COMMENTS

25 August 2023

Pierina N. Fayish
NEPA Compliance Officer
National Energy Technology Laboratory
626 Cochran Mill Rd, Pittsburgh, PA 15236

Re: Response to DOE/EA-2197D: Project Tundra, Environmental Assesssment

Dear Dr. Fayish:

Please find enclosed comments on DOE/EA-2197D: Project Tundra, Environmental Assesssment. I am an Associate Professor of Sustainable Energy Policy at the University of Notre Dame, submitting comments on behalf of myself as an individual. My expertise includes life cycle assessment, the US power sector, and carbon management.

My comment primarily addresses the critically flawed GHG life cycle analysis presented in the Draft EA, which contains both significant mathematical and structural errors. Given the importance of life cycle GHGs of a carbon management project for evaluating its prudence, this highly erroneous LCA presents a significant impediment to public engagement.

Sincerely,

Dr. Emily Grubert, PE
Associate Professor of Sustainable Energy Policy
Concurrent Associate Professor of Civil and Environmental Engineering and Earth Sciences
University of Notre Dame
egrubert@nd.edu
574.631.5911

Summary

1-1 The draft environmental assessment (EA) provided for Project Tundra, a proposed carbon capture and storage (CCS) retrofit of the Milton R. Young (MRY) coal-fired power plant in North Dakota, includes an unacceptable life cycle assessment (LCA) – arguably one of the most critical elements of the EA. The LCA does not provide accurate and meaningful information to the public.

The LCA only addresses greenhouse gases (GHGs) and contains numerous serious errors that should have been obvious to anyone familiar with life cycle methods, and should have prompted questions even for people unfamiliar with life cycle methods. Although the Draft EA is in response to a National Environmental Policy Act (NEPA) requirement associated with funding under Funding Opportunity Announcement (FOA) 1999, rather than to either of the two funding opportunities (FOA 2711 and FOA 2962) that might fund future project activities, note that one of the two – FOA 2962, focused on CCS rather than carbon storage alone – requires an LCA. The LCA presented in the Draft EA is fundamentally nonresponsive to the guidance put forth in
1-2 FOA 2962, most significantly by 1) not evaluating impacts per unit of delivered electricity (LCA results "shall be normalized to 1 MWh of electricity"); 2) not providing sensitivity analysis ("A sensitivity analysis shall be provided for key model inputs…") and 3) not evaluating non-GHG impacts ("the scope of environmental impacts shall include all the additional impact categories listed in Section 2.1.8.2 of the NETL CO2U LCA Guidance Document").

Recognizing that the terms of the current funding under FOA 1999 might not require the same level of detail under an LCA as FOA 2962, not making an LCA at the level of detail required by 2962 available to the public severely limits the public's ability to meaningfully engage on the environmental implications of Project Tundra. Not providing a 2962-compatible LCA is particularly puzzling if such an LCA already exists (e.g., if Project Tundra applied for a grant under FOA 2962, as has been reported in the media[1]). In any case, what has been provided in the Draft EA is unacceptably flawed, regardless.

Particularly given that GHG reductions are the main purpose of CCS on a plant like MRY, the LCA is crucial for understanding whether public investment is prudent and is a critical evaluation tool for both project evaluators and the public. Publicly issuing this LCA is both confusing and disrespectful to stakeholders for whom accurate information is now delayed, and who are asked to spend time to respond to a critically flawed analysis. Given the increasing attention to LCA in numerous federal processes, including statutory requirements for LCA in some cases, the fact that this LCA was issued publicly by DOE with such serious flaws raises
1-3 significant questions about capacity. Moreover, the fact that DOE recommended proceeding with this CCS project, despite (incorrect) LCA results suggesting that the CCS project would generate more than 3 kilograms (kg) of carbon dioxide-equivalent (CO_2e) per kg CO_2 sequestered, is deeply concerning for the integrity of the carbon management program and its ability to provide meaningful climate benefits in exchange for substantial investment.

The remainder of this comment addresses major errors of the LCA and its incompatibility with requirements under FOA 2962 (the CCS demonstration program under the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law), then describes additional needs for the future LCA. Given the seriousness of the problems with the LCA in the Draft EA, this comment is not intended to be exhaustive in its critiques, but rather highlights major concerns.

---

[1] https://bismarcktribune.com/news/state-regional/business/experts-say-project-tundra-carbon-capture-plans-may-not-be-worth-climate-financial-risks/article_cfa437f2-24b6-11ee-9769-2f63d327da25.html

Errors

1-4 The LCA in the Draft EA contains numerous serious errors. Possibly most significantly, the LCA interprets a sulfur hexafluoride (SF_6) emissions factor provided in the FOA as being in SF_6 rather than CO_2e terms, despite stating correctly on page 3 of Appendix E that the emissions factor is given as CO_2e. The LCA multiplies the CO_2e value by the SF_6 100-year horizon global warming potential (GWP-100) of 23,500, and thus reports a value that is off by a factor of 23,500. This error leads the Draft EA to conclude that SF_6 emissions from transportation and distribution of electricity, which is not relevant to the functional unit of CO_2 stored in any case, contribute 1.84 kg CO_2e/kg CO_2 stored. Although the document notes in several places that such emissions would have occurred with or without the CCS project, which also should have been a signal that it was inappropriate to include this value in the LCA scope, there is no reflection on the implication of such a large value. This result is obviously in error: given any familiarity with GHG emissions profiles for the United States, or observation of the extensive attention to GHG mitigation from power plants but essentially none given to GHG mitigation from transmission and distribution lines, the preparers should have recognized immediately that something was wrong. The fact that this error not only was submitted, but passed (ostensibly) several stages of review, is a serious issue that should have been identified at numerous points before the Draft EA was released. The GHG balance of the CCS plant is arguably among the most important elements of the Draft EA, so this level of inattention is extremely concerning relative to the rest of the Draft EA as well.

It is worth acknowledging that OCED's FOA 2962 guidance bears some responsibility here, namely for offering the SF_6 inventory value without a clear unit (as "7.87E-05 kg/kg CO_2 stored" without noting "kg CO_2e") – but again, the impact of this misinterpretation is so large that someone should have noticed and clarified with OCED if there was any confusion.

1-5 Relatedly, OCED provided AR5 GWP values but labeled them as AR6 values (despite clearly linking to AR5, which is stated in the web link address): again here, an experienced LCA analyst should have noticed this and commented on it, particularly because the methane GWP meaningfully changed between the AR5 and AR6 issuances, but this is an error within the FOA itself. Note, however, that the way the EA references the GWP table (repeatedly referring to the AR6 Appendix J) suggests that the preparers do not know what AR6 is – AR6, the Intergovernmental Panel on Climate Change's 6th Assessment Report, is one of the most important documents in climate analysis and should be familiar to LCA preparers. OCED's errors are also cause for concern, given that they dictate how the LCAs must be carried out, but these errors reflect sloppiness rather than incompetence.

Other errors in the LCA are potentially even more concerning given that they both

1-6 indicate further analytical inattention and stem from deep misunderstandings of the way that both CCS and LCA work. Most significantly, the LCA claims that the total emissions associated with the capture facility are 38,000 tonnes/year associated with startup, shutdown, and malfunction of the carbon capture system – a trivial value. Anyone familiar with carbon capture should be well aware that carbon capture is energy intensive, and therefore carries a GHG emissions burden when that energy is provided by GHG-emitting fuels, like lignite coal in the case of MRY. Ignoring the emissions associated with the capture unit's operations is puzzling and deeply concerning. One potential explanation is that the preparers lumped together all emissions from coal combustion into one process without allocating emissions to either carbon capture and storage or electricity production, which is inappropriate for an LCA and also contradicts statements (e.g., page 3-9) within the Draft EA that all emissions from the power plant would

happen with or without the intervention (in which case they should not be assigned to the
functional unit). Relevant notes in the LCA also suggest gross errors in evaluation that should
1-7 have been readily apparent to reviewers with or without LCA experience. Namely, the LCA does
acknowledge the energy intensity of carbon capture – claiming that the capture unit would
consume 1,836 megawatts (MW) of power and 600 gigajoules (GJ) per day of steam, and that
this consumption would simply reduce the output of MRY with "minimal cumulative impact on
GHG emissions." The source of these values is unclear, but note that the entire capacity of MRY
is only about 680 MW – a factor of 2.7 smaller than the claimed parasitic power load. As such,
the claim of 1,836 MW of power draw (which, according to the LCA, results in 0 additional
emissions) is on its face incorrect, and otherwise would have extremely significant impact on
cumulative GHG emissions. The claim of 600 GJ per day of steam consumption is unusually
small (accounting for an estimated <0.05% of the plant's typical energy inputs), and steam
demand is usually characterized as parasitic power load for coal CCS (because steam is
otherwise used to make power), which also raises questions about the nature, source, and
accuracy of these values.

In general, given the LCA's purported functional unit of a tonne of CO_2 stored, the stated
1-8 scope of the analysis reveals serious flaws. I discuss below that it is also incompatible with the
FOA 2962 LCA guidance that it repeatedly references, which requires normalization to 1 MWh
of electricity. For the LCA as presented, though, the scope includes numerous activities that are
irrelevant to the function of storing 1 tonne of CO_2, which the analysis claims as its functional
unit. Electricity transmission and distribution in particular should not be assigned to CO_2 storage,
and only the MRY emissions generated in order to capture and store the CO_2 are relevant. Such
an LCA of GHGs associated with per-tonne stored CO_2 could be useful for identifying carbon
return on carbon invested or similar metrics, but is fundamentally not very useful for evaluating
the effectiveness of a CCS project on a power plant (whose primary function is to deliver
electricity) – likely why FOA 2962 requires an LCA based on electricity delivered, not CO_2
1-9 stored. Regardless, the inclusion of irrelevant unit processes, and the failure to include well
known contributions to the CO_2 intensity of CO_2 storage – including reservoir leakage and, as
mentioned above, the emissions associated with energy used to capture, compress, and transport
CO_2 – is puzzling and incorrect even under the terms of the LCA as presented.

Incompatibility with Requirements for FOA 2962

Although this EA is not directly responding to FOA 2962, note that the MRY CCS project
1-10 is likely eligible under Topic Area 1 (TA-1), "CCS Demonstration at a Coal Electric Generation
Facility," of FOA 2962 and might have already applied (the FOA closed in May 2023, with
selection notifications expected in August 2023 – and potentially will have been released prior to
the closure of this public comment period). As such, it is reasonable to wonder whether an LCA
responsive to FOA 2962 already exists, in which case its exclusion from this Draft EA could be
an inappropriate withholding of information from the public.

The LCA presented in the Draft EA is incompatible with the FOA 2962 requirements,
1-11 most notably in that it selects a functional unit of 1 kg CO_2 stored rather than the required
functional unit of 1 MWh delivered electricity. It also fails to provide a required sensitivity
1-12 analysis and excludes required data on "chemical inputs to the facility" and "construction of the
facility and manufacturing impacts for the required materials/equipment." Further, the LCA does
not use the required CO_2 transport and saline aquifer storage life cycle inventory values
1-13 presented in the FOA, indeed, ignoring any potential reservoir leakage. The guidance also

1-14 requires results for several non-GHG impacts: Acidification Potential, Eutrophication Potential, Photochemical Smog Formation Potential, Ozone Depletion Potential, Particulate Matter Formation Potential, and Water Consumption, which are neither included nor mentioned, but are highly relevant for public engagement with LCA information.

Given that the LCA preparers clearly had access to FOA 2962, and specifically had access to Appendix J (the LCA guidance), it is extremely unclear why they failed to generate information compatible with these highly relevant requirements, which both ensure a greater degree of public access to environmental impact information and provide guidelines for conducting a rigorous LCA. This failure not only contributed to the highly erroneous analysis presented in the Draft EA, but has delayed public access to accurate and decision-relevant information about a project being proposed for substantial public support.

<u>Other notes</u>

The LCA presented in the Draft EA is unacceptably flawed for numerous reasons.
Attention to addressing these basic flaws can unfortunately distract from more nuanced critiques,
which is a major challenge given the complexity of high quality LCA, and that federal efforts
increasingly rely on LCA that, as this draft shows, might not meet basic quality requirements and
thus require significant capacity building even before more advanced concerns can be raised,
often because problems might not be visible until details are clear. One obvious problem with the
1-15 Draft EA, though, is that the No-Action Alternative does not account for implications of not
retrofitting MRY. The two units at MRY are 53 (Unit 1) and 46 (Unit 2) years old, respectively.
On average, US units with the same fuel and technology retire after 50 years of operation. A CCS
retrofit would likely lead to a lifespan extension given both the significant investment and likely
upgrades/repairs to the units to accommodate capture, but without the retrofit, plant retirement
should be expected in the near- to medium-term. This expectation is particularly relevant given
recent EPA proposed rules under Section 111 of the Clean Air Act, requiring coal plants to either
close by 2032, restrict capacity factor to 20% and close by 2035, co-fire with natural gas and
1-16 close by 2040, or install CCS. Although the rulemaking is not final, it is inappropriate for the the
"No-Action Alternative" to assume that MRY will indefinitely operate unabated, both because of
infrastructure lifespan limits and because of potential GHG rules. As such, emissions abatement
caused by CCS over the planned CCS operational period are more appropriately compared to
emissions expected in a scenario where MRY does not receive lifespan-extending capital
investment and might be subject to closure or other compliance requirements. This nuance also
means that estimating abatement potential based on the highest fuel use year, rather than based
on individual operational year projections, is inappropriate.

From: Drew Harper
To: Fayish, Pierina M.
Subject: [EXTERNAL] Project Tundra
Date: Friday, September 15, 2023 6:30:02 PM

Hello,

2-1 I would like to submit a public comment in relation to the proposed carbon capture and sequestration project known as 'Project Tundra'. I consider this a significant waste of taxpayer funds, since I believe a thorough economic analysis would show that the coal-fired power plant could likely be substituted for renewable technologies at a lower cost than even the carbon capture technologies. Further, I find it deeply alarming that the costs continue to increase, timelines continue to extend, and technical estimates for the amount of sequestered carbon continue to decrease. I wish to leave a world with minimal impacts of climate change for future generations. I do not believe Project Tundra is a step forward in making that a reality. For these reasons, I hope the Department of Energy chooses NOT to provide grant funding to Project Tundra.

Thanks for your consideration,
Drew Harper

From: Charlie Botsford
To: Fayish, Pierina M.
Subject: [EXTERNAL] Project Tundra Comments on NEPA Draft Environmental Assessment
Date: Sunday, September 17, 2023 10:21:34 PM

3-1 The socioeconomic Section 3.13 appears deficient. At a minimum, Section 3.13 should include an additional subsection that addressed impacts to electricity customers of MRYS (or equivalent station). For example, addition of the carbon capture and storage system will substantially increase electricity prices to the electricity cooperative customers that MRYS services.

This increase in electricity price should be compared with the "no project" alternative in which MRYS would retire operations in 3-5 years and new, lower cost power generation would take its place. MRYS, at ~50 years in operation, in any analysis would be deemed near end-of-life. DOE analyses show that only one coal-fired power plant in the US is marginally profitable, and that particular plant does not have the economic burden of carbon capture and storage. Thus, adding carbon capture and storage to MRYS would increase the price of electricity for its few remaining years in operation until it retires for market reasons. The draft EA notes that local socioeconomic impacts would be minimal. Retiring MRYS and replacing it with low cost power generation should also have minimal socioeconomic impacts, but in any case, this analysis should also be presented in the draft EA.

Best Regards,
Charles Botsford

From: Justin Paynter
To: Fayish, Pierina M.
Subject: [EXTERNAL] Project Tundra public comment
Date: Monday, September 18, 2023 9:54:42 PM

4-1 Project Tundra should not be allowed to proceed based on the current information available. This project is an example of greenwashing in an attempt to keep fossil fuels online. The carbon emissions projections have bounced around and gradually gotten lower. Under scrutiny it is shown that the projections are overestimating the amount of carbon that can be captured and underestimated the amount of carbon released.

If this carbon capture project moves forward it will emit more carbon emissions than it sequesters, pushing our climate goals in the wrong direction. DOE funds will be better spent in other climate projects such as transmission buildout and new large renewable energy projects. The economics of coal are already poor, and adding additional cost while increasing overall emissions is the wrong way to go.

Thank you,
Justin Paynter
Epping NH

Sent from my iPhone

Indigenous Environmental Network

PO Box 485
Bemidji, MN 56619

19 September, 2023

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236
412.386.5428

Re: Comments on the Draft Environmental Assessment (EA) for the proposed North Dakota CarbonSAFE: Project Tundra (DOE/EA-D2197).

To: The Department of Energy and the Office of National Energy Technology Laboratory,

The Indigenous Environmental Network (IEN) submits this document based on the call for comments on the Draft Environmental Assessment (EA) for the proposed North Dakota Carbon SAFE: Project Tundra (DOE/EA-D2197). IEN is a non-profit 501(c)3 Indigenous-led organization based in Minnesota, United States with remote offices throughout North America, Turtle Island. IEN is an alliance of Indigenous Peoples whose mission it is to protect the sacredness of Mother Earth from contamination and exploitation by strengthening, maintaining and respecting Indigenous teachings and natural laws.

General Comment

After thorough review of the proposed North Dakota CarbonSAFE: Project Tundra and the draft environmental assessment prepared by the Department of Energy (DOE), the Indigenous Environmental Network has serious concerns about the DOE's assertion that there are "no significant adverse environmental impacts," and unequivocally oppose the approval of the project.

IEN finds that the Draft EA has a flawed analysis of the potential impacts of the project and fails to demonstrate the essential need for the project, raising questions about its fundamental purpose and justifiability. The No-Action Alternative presented in the assessment is deeply troubling, as they appear under-researched, misrepresented, and misleading. The assessment fails to adequately explore a reasonable and more desirable range of impacts from the No-Action Alternative to the proposed project.

The assessment's lack of attention to the socio-economic implications of the project is another pressing concern. Issues regarding environmental justice were poorly presented and not well integrated into the analysis, which raises significant concerns about the project's potential impacts on Tribes, Indigenous Peoples, and marginalized communities near Center, Oliver County, and North Dakota at large.

Another troubling shortcoming in the assessment lies in its inadequate evaluation of the cumulative impacts of the project on greenhouse gas (GHG) emissions and climate change. There is a wealth of empirical evidence and examples showing that engineered carbon removal technologies consistently underperform, are unproven and end up releasing more emissions than they promise to capture. Additionally, the risks associated with Minnkota deciding to pursue enhanced oil recovery (EOR) in the future due to economic inefficiencies from carbon capture and storage (CCS) technologies and applications were completely omitted.

IEN recognizes CCS technologies as a false solution to the climate crisis. Over the course of two decades, IEN has consistently resisted and opposed carbon trading and carbon offset projects, and IEN has witnessed CCS repeatedly fail to uphold Tribal sovereignty and Indigenous Peoples' rights, address climate change, and/or reduce emissions. Instead, CCS has often facilitated polluting industries, particularly coal, oil and gas, to continue business-as-usual practices, perpetuating environmental exploitation and destruction.

In light of these concerns, IEN urges the DOE to abandon the North Dakota CarbonSAFE: Project Tundra and select the No-Action Alternative. However, should the DOE choose to persist with the project despite its devastating environmental, economic, social, cultural, and climate impacts, we implore the DOE to reassess the scope of the analysis and continue to conduct a thorough Environmental Impact Assessment (EIA) as mandated by the National Environmental Policy Act (NEPA). Such an assessment must fully account for the risks and potential impacts of the proposed project, fully explore no-action alternatives, and adhere to robust consultation processes and Free, Prior, and Informed Consent (FPIC) with Indigenous Peoples. The CarbonSAFE: Project Tundra project should be rejected as it will lock-in coal and fossil fuels for years to come in a time when coal and fossil fuel phase out and a just energy transition is crucial for the future of this planet.

Detailed Comments

A. The Draft EA fails to demonstrate that the proposed project is needed and justifiable.

5-1 The Draft EA attempts to justify the need for the proposed North Dakota CarbonSAFE: Project Tundra by citing the need for the advancement of commercial Carbon Capture and Storage (CCS) technologies. However, a closer examination reveals serious deficiencies in this argument.

Firstly, the assertion that this project is needed to reduce the risks and costs for future CCS projects and to bring more storage resources into commercial classification lacks substantial evidence and reasoning. The presumption that this project alone will pave the way for a dangerous and unproven industry for "secure" geologic carbon storage is problematic, given the complexity of geologic carbon storage and the varying geological conditions across regions (Song et al., 2023). For instance, the determination of the total pore volume within a prospective storage formation, which constitutes one of the initial steps in estimating the capacity of a deep
5-2 saline reservoir, necessitates the multiplication of several geological parameters. These parameters include the areal extent, thickness, and porosity of the storage formation(s) at depths suitable for carbon storage. While the mathematical process may seem straightforward, it introduces a considerable degree of variability across assessments. This variability arises due to disparities in geological data, reservoir conditions, the definition of storage space, data quality, and the level of detail considered in different assessments (Global CCS Institute, 2016). Consequently, the complexity of geologic carbon storage and the diverse geological conditions across regions demand a more nuanced and site-specific approach to assessing the feasibility and reliability of such projects, and the proposed project in North Dakota alone will not be representative of geological conditions of other commercial coal-fired power plants to reduce the risks for commercial development of CCS.

Additionally, the claim that the project is necessary for supporting the President's
5-3 emissions reduction goals remains unsubstantiated. While addressing climate change by reducing emissions is paramount, the direct link between this specific project in Oliver County and the achievement of these objectives remains unclear, particularly given the absence of empirical evidence demonstrating that CCS technologies and development correlate with emission reductions. On the contrary, research continues to demonstrate that CCS requires more energy input to function and provides polluting industries a license to increase extraction and combustion of fossil fuels, which causes climate change (Climate Council, 2023).

5-4 To assist the public and decision-makers in determining whether the DOE should invest taxpayer dollars in the proposed project, it is imperative that the EA address the fundamental questions of whether this project is genuinely necessary for its intended goals. The EA fails to address even the most fundamental issues. For example, if the purpose of this project is to showcase that the successful implementation of CCS in North Dakota will lead to commercial success, the DOE must provide robust scientific evidence and analysis to support this assertion. This should entail comprehensive studies demonstrating how the North Dakota project can serve

5-4 cont'd as a representative model for other facilities and regions while ensuring safety and real carbon emissions reductions. Moreover, the evidence would include how and whether it is possible for

5-5 the outcomes of the proposed project, including GHG emissions reductions and carbon sequestration capacity, could align with national climate objectives.

As it stands, the EA is unclear at best. This is likely due to the lack of evidence for CCS to *permanently* capture, store and/or reduce GHG emissions. Without clear and accurate information on how the proposed project can achieve its intended goals as identified by the Draft EA, it is impossible to make a reasonable determination of whether the project is needed, or whether to invest taxpayers' dollars into dangerous, unproven, and unsustainable technologies such that of CCS.

B. The Draft EA fails to adequately explore the reasonable range of impacts from the No-Action Alternative, making the analysis inaccurate and misleading.

5-6 The Draft EA falls short of adequately exploring a reasonable range of impacts under the No-Action Alternative, leading to a fundamentally flawed analysis that is inaccurate and misleading. The EA makes the assumption that under the No-Action Alternative, "Minnkota would continue to operate the Milton R. Young (MRY) facility under normal conditions." This assertion fails to consider crucial contextual and historical factors of the facility. The age and condition of the MRY facility are essential elements that cannot be overlooked under the No-Action Alternative analysis. According to the U.S. Energy Information Administration (EIA), the average operating coal-fired generating unit in the United States is 45 years old, and units built in the 1980s and 1990s are scheduled to retire. Globally, historical data also suggests that the average retirement is around 37 years (Montrone et al., 2023). In contrast, the MRY facility has been in operation since 1970 (Minnkota Power Cooperative, 2020), making it more than 50 years old, exceeding its expected operational life span and nearing retirement. As stated in the Draft EA, the facility's Title V permit is set to expire in May 2025, requiring significant retrofitting and renovating or rebuilding efforts for continued operation, if even possible.

Contrary to the DOE's assumption, it is virtually certain that the MRY facility will not continue to operate under "normal conditions." Expert consensus supports the notion that the plant will inevitably be retired, most likely upon the expiration of its Title V permit, creating opportunities to explore cleaner, more sustainable and equitable sources of energy (Gearino, 2023). Consequently, the environmental consequences attributed to the No-Action Alternative presented in the Draft EA are rendered invalid and inaccurate. This begs the question if the facility plans to use the potential influx of CCS funding to retrofit the aging facility, which is not the purpose of the funding and could open the project up to legal action in the future.

For instance, IEN is confident that under the No-Action Alternative, the recipient will not pursue the project, and the MRY will be forced to be decommissioned. Thus, air quality in the

proposed project area, Center, and North Dakota as a whole, would significantly improve as the
5-7 plant is phased out. Similarly, the retirement of the MRY facility will open doors for the opportunity for Oliver County and North Dakota to embrace the renewable energy transition by investing in and building cleaner, lower-cost alternative sources of energy. The upstream emissions reduction resulting from the decommissioning and investment in alternatives would have a substantial and cumulative positive impact on GHG emissions and climate change. This is only one example to underscore how the impact analysis under the No-Action Alternative could have been further explored had it accurately accounted for the context and conditions of the aging MRY facility and recognized the inevitability of its decommissioning.

5-8 Furthermore, the Draft EA's statement that the President's emissions reduction goals would not be advanced is predicated on the incorrect assumption that the CCS technologies of the proposed project are the sole means of achieving these objectives. The portrayal of CCS technologies as a necessity in the fight against climate change in the Draft EA is not only false but also concerning, especially when applied to facilities of this scale and age. For example, Cui et al. (2019) conducted a comprehensive quantitative analysis to assess the operational lifetimes of coal power plants in alignment with the Paris Agreement's climate goals. Their findings indicate that, in a scenario where no new capacity comes online, the global phase-out of coal can be brought into alignment with the 2°C warming limit by reducing the operational lifetimes of coal-fired power plants to 35 years. This scenario involves the retirement of all coal-fired units after they have served for 35 years, including immediate retirement for plants that have already exceeded this limit. In a more ambitious 1.5°C scenario, the operational lifetime threshold is further reduced to just 20 years. Furthermore, in North Dakota, there has already been momentum to phase out coal-powered energy production. Great River Energy (GRE) retired their relatively younger, larger, and better-running Coal Creek Station, and replaced it with cheaper, cleaner wind and solar technologies (Kandiyohi Power Cooperative, 2022).

5-9 In light of these deficiencies, IEN emphatically urges the DOE to rectify the inadequacies in exploring a reasonable range of impacts under the No-Action Alternative, giving due consideration to the facility's life cycle and outdated infrastructure to ensure safety and efficiency. Such measures are crucial to conducting a rigorous, comprehensive, and accurate assessment and portrayal of the benefits and trade-offs of the proposed project. Communities deserve to know the full extent of the impacts and consequences of the No-Action Alternative in order to make informed decisions that align with the realities of energy infrastructure transition and address climate change in an reliable way.

C. The Draft EA fails to address the potential impacts and risks to air quality from the suite of pollutants that would result from the proposed project.

5-10 The analysis of the potential impacts on air quality in the Draft EA failed to address the risks associated with the full suite of pollutants that would result from the proposed project. While the analysis focuses on the MRY facility's current compliance with existing state and federal air quality standards, it neglects to adequately consider the substantial increase in hazardous air pollutants (HAPs) stemming from the proposed project, which go beyond CO_2. These additional pollutants are associated with both on-site direct emissions during the construction and operation of the CCS facility and the indirect upstream emissions from fuel extraction processes.

It is imperative that the analysis underscore the fact that CCS technologies, designed primarily for CO_2 emissions, do not address other critical pollutants, including sulfur dioxide (SO_2), nitrogen dioxide (NOx), organic gasses, mercury, toxins, black and brown carbon, fly ash, and various aerosol components (Jacobson, 2019). Although the Draft EA highlights investments
5-11 made between 2006 and 2015 to reduce SO_2 and NOx emissions at the MRY station, it is essential to contextualize this investment as a result of legal action from the Department of Justice and the U.S. EPA. The facility was found violating the Clean Air Act in 2006, and in that year, MRY was the second-largest emitter of NOx pollution in the nation. As a result of the settlement, the MRY was required to install NOx reduction systems along with a new SO_2 pollution flue gas desulfurization device (scrubber) to reduce SO_2 emissions (Global Energy Monitor).

5-12 However, the critical issue unaddressed in the Draft EA is how the proposed project will manage the increased emissions of pollutants other than CO_2, especially since the emissions modeling of the facility is already creating maximum projected fuel consumption scenarios.
5-13 Furthermore, introducing CCS technology to a power plant adds a significant demand for energy to operate the system. This increased demand for energy translates into the need for more fuel to be extracted and consumed, resulting in electricity generation coupled with CCS requiring up to 44 percent more fuel than standalone power generation (Clean Energy Group, 2023). The additional fuel consumed to power the technology can lead to a significant increase in particulate and NOx emissions, ranging from 5 percent to as much as 60 percent (Hertwich et al., 2014).
5-14 Even if power plants install supplementary pollution controls, they may still emit pollutants at rates comparable to existing, newer natural gas plants. The Draft failed to mention whether existing pollution control systems at the MRY facility, such as the current scrubbers, are capable of limiting emissions or will be retrofitted or expanded to accommodate these additional HAPs. It appears that the model used in the air quality analysis assumes the static efficiency of the scrubbers without factoring in capacity loads or the necessary adjustment to address the influx of pollutants introduced by the CCS technology. This oversight is particularly concerning given that
5-15 the EA defines Center as an environmental justice (EJ) area. Numerous studies have shown that pollutants, including fly ash and fine particulate matter (PM10), emitted from coal-fired power plants can disperse over significant distances as far as 30 km away from the location of the plant

5-15 cont'd due to wind patterns (Kravchenko et al. 2018; Iordanidis et al. 2008). Given that Center is located within a mere 4.5 miles (7.2 km) from the proposed project site, the Center community is directly put in a position of harm. It is imperative to conduct a comprehensive analysis of how air quality in this environmental justice community could be affected by the project's elevated emissions.

5-16 Furthermore, the Draft EA's conclusion that the impacts on air quality during the project's construction would be minor and temporary, solely based on the implementation of "best practices," warrants a more thorough review and examination. Given the historical necessity of legal action to install pollution reduction systems at the MRY facility, local communities deserve transparency and scientific evidence regarding Minnkota's plans to address the increased HAPs.

D. The Draft EA fails to address the potential adverse impacts on socio-economic conditions that could result from the proposed project.

5-17 The Draft EA's treatment of socio-economic impacts stemming from the proposed project is inadequate and incomplete. While the assessment does acknowledge potential short-term economic benefits during the project's construction, it did not provide a sufficient analysis of the complex, long-term socio-economic dynamics that could significantly impact Tribes, Indigenous Peoples and local communities. For example, the benefits expected from the construction of the project on the labor market, housing market, business, and sales tax were presented in the absence of empirical evidence and data inputs to substantiate such claims.

5-18 More troublingly, the analysis on socio-economic failed to analyze how the proposed project would affect the cost of electricity to local communities and energy consumers in the region, which is a major socio-economic issue. A comprehensive report published by the Institute for Energy Economics and Financial Analysis (IEEFA) in 2020 highlights the immense uncertainty surrounding the financial aspects of adding the CCS technology to the exciting MRY facility infrastructure, and the implications it has on energy consumers. IEN would like to highlight some of the critical concerns expressed in the report:

5-19
1. Uncertainty over the project's ability to capture enough CO_2 to be financed through federal 45Q tax credits. If additional funds are required for construction and operation, these unexpected costs would ultimately be borne by ratepayers.

5-20
2. Retrofitting could impact the plant's operating performance, raise operating costs, and necessitate significant maintenance expenditures, especially when it comes to Unit 2, ultimately further burdening ratepayers who are already paying above-average prices for power relative to the scenario where their co-ops purchased the same amount of power from competitive wholesale markets.

5-21
3. The impact on Minnkota's customers depends on how the co-op decides to charge for electricity and steam used by the CCS technology. Different financial

5-21 cont'd

relationships and charging structures could result in consumers carrying the cost more than investors and developers.

5-22 The potential impacts on the cost of electricity and power are crucial socio-economic consequences that were troublingly absent in the Draft EA. A more robust and comprehensive analysis of the project's intended cost structure, along with its potential repercussions on ratepayers and energy consumers is necessary. Furthermore, future assessments must include plans to ensure energy equity in cases of incurring additional costs and expenditures, ensuring transparency regarding the long-term implications and cumulative impacts for local communities and the socio-economic status of the affected regions. This analysis will also have significant implications on the analysis regarding environmental justice and how local communities could be affected by inequitable cost structure.

E. The Draft EA presents a limited and inadequate analysis of Environmental Justice implications that would result from the proposed project.

5-23 The Draft EA's handling of Environmental Justice (EJ) issues raises serious concerns. The Draft asserts that environmental, health, and occupational safety impacts would be minimal and "affect all populations in the area equally" without providing a sound scientific basis for such claims. These considerations do not address environmental justice. This oversight contributes to the flawed reliance on state-level data to establish thresholds for EJ consideration. Instead of engaging in due processes of consultation with the Tribes, Indigenous Peoples and leaders, the DOE's approach to defining EJ oversimplifies the local context of Center and the surrounding area, and overlooks the unique social dynamics of the project's surroundings.

5-24 The claim that "the project would be constructed and operated in a manner consistent with environmental justice considerations," and that "it would have positive socioeconomic effects on minority and economically disadvantaged populations, as well as the general population in the socioeconomic impact area because it would generate new temporary and permanent jobs and economic activity while reducing air pollutant emissions in the local community" lack supporting evidence. On the contrary, EJ advocates express significant concerns about CCS technologies. EJ communities are wary that the application of CCS could perpetuate the existence of polluting infrastructure and potentially lead to an expansion of pipelines, historically routed through marginalized communities (Chemnick, 2022). The White House Environmental Justice Advisory Council's recommendation to exclude CCS projects from the Justice40 Initiative underscores the danger CCS technologies pose to marginalized and disadvantaged communities. The overall potential of CCS funding being used to retrofit a polluting and aging facility would have devastating socio-economic and cultural impacts on Tribes, Indigenous Peoples and surrounding communities by creating a lock-in effect that would

5-24 cont'd guarantee the continuation of fossil fuel extraction, rather than build towards an inclusive and just energy transition.

F. The Draft EA fails to adequately explore the cumulative impacts of the proposed project.

5-25 The Draft's approach to assessing the cumulative impacts of the proposed project on climate change and society is fundamentally flawed and leaves critical questions unanswered. While "cumulative impacts" are defined as the incremental effect when added to other past, present, and foreseeable future actions, the draft's analysis predominately focuses on comparing the build versus no-build scenarios. This approach disregards the wealth of research and empirical evidence pointing to the likelihood of malfunction and the project's unproven ability to deliver the expected carbon sequestration capacity post-construction (Kelemen 2019; Cushing 2018; Chen, et. al., 2022; Onyebuchi et.al., 2018; Batres, et. al. 2021). Case examples of CCS technologies most similar to the case of the MRY facility are the only two carbon capture projects at coal-fired power plants in the entire world–Petra Nova and Boundary Dam 3 in Saskatchewan.

Petra Nova's carbon capture facility was installed at a coal-fired power station near Houston, Texas in 2017 and, at the time, was hailed as a promising endeavor to reduce emissions from fossil fuels. However, a report by NRG published in March 2020, which owns 50% of Petra Nova, revealed significant performance problems during the project's initial three years of operation. According to Petra Nova's technical report submitted to the DOE, the facility only captured 1.071 million metric tons of carbon dioxide in 2017, **a mere 7% of the 15.295 million metric tons emitted** by the W.A. Parish Generating Station. In 2018, the project only captured 1.017 metric tons, representative of 6.9%, of the plant's total 14.620 million tons (Smyth, 2020). The report submitted also showed that Petra Nova received Notices of Violations from the Texas Commission on Environmental Quality and from the Texas Railroad Commission, the latter concerning the carbon dioxide pipeline. Furthermore, the captured carbon from Petra Nova had been used for EOR, contributing to an unknown amount of additional CO_2 into the atmosphere, along with other dangerous pollutants. Eventually, even with EOR in place, the operation was considered economically unviable and the CCS facility, along with the gas plant used to power it, were shut down, leaving the coal-fired plant as emissions-intensive as ever.

Boundary Dam 2 was another notable CCS project that failed to deliver on its promises. The facility aimed to capture CO_2 emissions from a 110MW coal-fired power plant, with the goal of capturing 1 million metric tons of CO_2 annually. However, data published by SaskPower, the project's operator, indicated that the facility experienced significant challenges with a low capture rate from 2014 to 2019 (Schlissel, 2020). The issues faced by Boundary Dam 3 echoed those of Petra Nova, falling way short of the project's stated objectives.

5-26 The Draft EA dismisses substantial scientific and empirical evidence that suggests that CCS technologies frequently fail to meet their objectives and are more likely to use funding to retrofit aging facilities that in the long-term increase costs and economic inefficiencies. Especially since its inception in the 1970s, CCS was designed to squeeze out the remaining oil from deep wells through a process known as **Enhanced Oil Recovery (EOR)**. Currently, EOR is used in 21 of 27 CCS projects, which means that CCS is effectively a tool to further extract fossil fuels and leads to more carbon being released into the atmosphere –a reality that CCS lifecycle analyses (LCAs) routinely fails to address. These risks were troublingly absent from the life cycle analyses provided in this Draft EA. The DOE must account for these risks and include emissions from extracted and combusted fossil fuels that use EOR in the extraction process and in the EA's greenhouse gas assessments.

Conclusion

5-27 Due to the list of concerns and substantive comments, The Indigenous Environmental Network urges the Department of Energy to reject the proposed action and abandon the proposed North Dakota CarbonSAFE: Project Tundra. The DOE lacks significant and substantive evidence to consider this a viable project. IEN implores the DOE to reject this project due to the lock-in effect that this coal-fired and fossil fuel-based combustion facility will produce for years to come. If the DOE continues to consider this project, it must take into account the need for a full Environmental Impact Assessment as mandated by the National Environmental Policy Act (NEPA) to fully account for the risks and potential impacts of the proposed project. However, it is clear from the evidence presented above that Project Tundra should be rejected and the aging coal-fired power plant should be given a phase-out deadline.

Sincerely,

Tom Goldtooth

Tom BK Goldtooth
Executive Director
Indigenous Environmental Network
PO Box 485
Bemidji, MN 56619
(218) 751-4967

August 19, 2023

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236
412-386-5428

Submitted via email to Pierina.Fayish@netl.doe.gov

Re: Clean Air Task Force Comment on North Dokota CarbonSAFE: Project Tundra Draft EA, DOE/EA-2197

Clean Air Task Force ("CATF") submits this comment on the draft Environmental Assessment ("EA") for the proposed North Dakota CarbonSAFE: Project Tundra (DOE/EA-D2197). CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. With over 25 years of internationally recognized expertise on climate policy, science, and law, and a commitment to exploring all potential solutions, CATF is a pragmatic, non-ideological advocacy group focused on climate change and the clean energy transition. CATF has offices in Boston, Washington, D.C., and Brussels, with staff working remotely around the world.

6-1 CATF is commenting on the EA solely regarding the co-benefits of reducing sulfur dioxide ("SO_2)", nitrogen oxides ("NOx"), and particulate matter ("PM") that can be expected to result from adding carbon capture to the Milton Young Station. The installation of carbon capture on a given facility can be expected to reduce emissions of these pollutants due to the need to install additional pretreatment controls necessary for the efficient operation of the carbon dioxide ("CO_2") absorber, or via absorption of co-pollutants (air pollutants other than CO_2) in the CO_2 absorber. The draft EA includes an analysis of the potential emissions from the facility during periods when the carbon capture equipment has been turned off, but does not present the potential emission co-benefits that will occur when, as is expected to be the case, the carbon capture equipment is operating.

I. Expected Emissions Reductions

6-2 The draft EA should present the expected benefits from reductions in SO_2, NOx, and PM emissions that will occur when the capture unit is operating. The 2020 National Emissions Inventory shows the Milton R. Young Station ("MRY") emits a significant amount of these pollutants:

SO_2	NOx	PM_{10} (Filt + Cond)	$PM_{2.5}$ (Filt + Cond)
2,676.8	8,558.5	616.4678	372.5578

6-2 cont'd These pollutants can interfere with the amine used to remove CO_2 in the absorber column by binding with the amine to form heat stable salts. Pretreating the flue gas prior to entering the column removes many of these pollutants to ensure the efficient operation of the capture unit.

As noted in the air permit application, the project includes both a wet electrostatic precipitator ("WESP") to control particulate matter and a quencher with caustic injection to control sulfur compounds:

- Wet Electrostatic Precipitator (ESP)

  The wet ESP, located upstream of the flue gas Quencher, will be installed to treat the flue gas prior to the carbon absorption process. The WESP will reduce the concentration of both particulate matter (PM) with an aerodynamic diameter of 10 microns or less (PM10) and PM with an aerodynamic diameter of 2.5 microns or less (PM2.5) in the flue gas as needed to support treatment in the CO2 absorber column.

- Quencher

  This unit cools the flue gas from MRY Units 1 & 2. Caustic may be added to the Quencher to further reduce sulfur dioxide (SO2), sulfur trioxide (SO3) and sulfuric acid mist (H2SO4) in the flue gas as needed prior to treatment in the CO2 absorber column.[1]

6-3 For amine-based CO_2 capture systems proposed at the Milton Young station, SO_2 concentrations of 10 ppm or lower are typically preferred.[2] These requirements could reduce SO_2 emissions from the plan by 99% or more, as compared with emissions before the application of these systems.

CATF is preparing a report on the co-benefits of carbon capture in the refining and cement industries. The consultant CATF retained contacted vendors of WESPs. Two vendors expected removal efficiencies of the WESP to be 90% with a single field, and 99% with the addition of a second field (although the second field nearly doubled the capital cost of the ESP).

6-4 NOx emission reductions are unlikely to be as dramatic at the Milton R. Young station as the sulfur and PM emissions reductions. Flue gas NOx consists of different species, including nitric oxide ("NO") and nitrogen dioxide ("NO_2"). These two species impact the amine solvent differently in a CO_2 capture system. NO has low solubility and does not impact the amine solvent or the CO_2 capture unit. However, NO_2 dissolves in water, and forms nitrous and nitric acids which neutralize the amine solvent. Appendix A of the air permit application contains the 2019 RATA test data showing that between approximately 6% to 8% of the NOx emissions from

[1] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plant Permit to Construct Application Revision 2, Appendix C: Case-by-Case MACT Determination (June 2, 2023) at 1 (pdf page 87), *available at* https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents.
[2] Nat'l Energy Tech. Lab., *IECM Technical Documentation: Amine-based Post-Combustion CO_2 Capture* (Jan. 2019).

6-4 cont'd the plant are NO_2. Therefore, the likely co-benefit of carbon capture in this instance on NOx emissions is likely to be no greater than an 8% reduction.

6-5 Secondary PM emissions arise downwind of the stack as SO_2 and PM undergo chemical changes after emission. Both secondary (post-emissions) and primary PM emissions contribute to premature death, and increased incidence of respiratory illnesses, for example, an increased risk of developing asthma, and of asthma attacks.

II. Expected Health Benefits from Emissions Reductions

To quantify the health benefits that arise from reducing SO_2, NOx, and PM from the project, the EA should use a model such as COBRA. COBRA was developed by Abt Associates in 2002 to support assessments of the human health damages from air pollution and their associated monetized economic damages. Abt Associates has for years served as U.S. EPA's air quality benefits consultant. The model has been updated periodically, with version 4.1 reflecting base-year emissions and calibrations for 2016 and a projection inventory for 2023 and 2028. To assess health impacts, the model uses a damage function approach, which involves modeling changes in ambient air pollution levels, calculating the associated change in adverse health effects, such as premature mortality, and then assigning an economic value to these effects. The baseline version of COBRA uses 2016 data: (1) model calibration to 2016 baseline monitored $PM_{2.5}$, (2) 2016 population estimates, (3) 2016 disease incidence rates, and (4) the most recent concentration-response functions; future years 2023 and 2028 have emissions, population and disease incidences grown from the base year, as appropriate.

The health impact functions are derived from concentration-response functions reported in the peer-reviewed, published epidemiological literature. A typical health impact function has four components:

1. an effect estimate, which quantifies the change in health effects per unit of change in a pollutant, and is derived from a particular concentration-response function from an epidemiology study;
2. a baseline incidence rate for the health effect;
3. the affected population; and
4. the estimated change in the concentration of the pollutant.

The result of applying these functions is an estimated change in the incidence of a particular health effect for a given increment of air pollution. Examples of health effects that have been associated with changes in air pollution levels include increased incidence of premature mortality, increased hospital admissions for respiratory and cardiovascular illnesses, and asthma exacerbation.

The second step in the damage function approach involves estimated unit values that give the economic value of avoiding a single case of a particular endpoint – a single death, for example, or a single hospital admission. These unit values are derived from the economics literature and

6-5 cont'd come in several varieties. By quantifying these impacts, the results can be added to the social cost of greenhouse gas ("SC-GHG") benefits described on page 3-54 of the EA.

Respectfully submitted,

Clean Air Task Force

contact
John Thompson, Technology & Markets Director
jthompson@catf.us
618-457-0137

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

September 19, 2023

Ref: 8ORA-N

Pierina N. Fayish
Department of Energy
National Energy Technology
Laboratory
626 Cochran Mill Road
Pittsburgh, PA 15236

Re: North Dakota CarbonSAFE: Project Tundra EA (DOE/EA-D2197)

Dear NEPA Compliance Officer Fayish,

The U.S. Environmental Protection Agency Region 8 has reviewed the U.S. Department of Energy's (DOE) August 2023 Draft Environmental Assessment (EA) for the proposed North Dakota CarbonSAFE: Project Tundra (hereinafter, "Project"). In accordance with our responsibilities under Section 102(2)(C) of the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act (CAA), we are providing comments to convey additional resource management considerations that we recommend addressing in the Final EA.

The Project proposes to construct a carbon capture facility at the Milton R. Young lignite-fired coal power plant (hereinafter, "plant") in Oliver County, North Dakota with an estimated carbon dioxide storage capacity of 4 million metric tons per year. To reach this storage potential the Project would include a 0.5-mile-long carbon dioxide flowline, up to three Class VI injection wells, up to two Class I disposal wells, and three monitoring wells on private land near the existing power plant.

Our detailed comments and recommendations for the EA are enclosed for your consideration. These comments focus on considerations regarding the operational life of the plant; the range of alternatives; analysis of greenhouse gas (GHG) emissions, impacts, and resiliency; and analysis of non-GHG air pollutant emissions.

We appreciate your consideration of our comments. If further explanation of these comments is desired, please contact me at (303) 312-6155 or mccoy.melissa@epa.gov. You may also contact Carolyn Gleason, Lead Reviewer for this project, at (303) 312-6441 or gleason.carolyn@epa.gov

The EPA is encouraging electronic submissions for all future NEPA notifications and document transmissions. The Final EA and any future DOE NEPA documents for EPA Region 8 review can be emailed to EPA-R8-NEPA@epa.gov.

Sincerely,

MELISSA MCCOY
Digitally signed by MELISSA MCCOY
Date: 2023.09.19 15:25:34 -06'00'

Melissa W. McCoy, Ph.D., J.D.
Manager, NEPA Branch
Office of the Regional Administrator

Enclosure

Enclosure -EPA Comments
North Dakota CarbonSAFE: Project Tundra EA

Operational Planning

7-1 According to the August 19, 2023, invitation to comment on the Project prepared by DOE, the Project as proposed would be the world's largest post-combustion carbon dioxide capture and sequestration effort if built. Due to this scale and the diverse funding necessary for the Project sequestration rates to become fully realized, continuity of operations at the plant is also important. We therefore recommend developing a discussion on the anticipated operational life of the plant and any reasonably foreseeable maintenance or infrastructural upgrades that would need to occur in order for the Project to meet its goals in the EA. This discussion should consider the potential implications of reasonably foreseeable future air quality and GHG regulations on coal-fired power plants on costs and continued operation of the plant. The potential environmental impacts related to these actions should also be explored in this discussion and in the resource analysis sections included in the Draft EA as applicable. Alternatively, the Final EA could consider a second No-Action Alternative that does not assume the units will continue operating indefinitely and may retire in the near future due to lifespan limits and potential air quality and GHG rules.

7-2 The federal funding decision being proposed may also impact the resources available to the Project proponents to facilitate its regular maintenance and may enable additional operational life for the plant beyond what its existing infrastructure would have otherwise allowed. This may create viability for coal-based power generation in this region that may disincentivize the development of alternative lower GHG-emitting technologies. These options may include natural gas-based power sources which produce fewer carbon dioxide emissions per kilowatt-hour or other less carbon intensive power sources such as biomass, hydro, solar, or wind.[1] We recommend discussing the general operational status of the plant in the Final EA and describing the alternative power generation options that could take its place. This would help illustrate to the public the comparative environmental advantage or disadvantage of supporting coal-based power generation in the region under the Project.

Range of Alternatives

7-3 Section 1.2 details that the CarbonSAFE funding program was developed to "fulfill the need for research into safe, efficient, and effective characterization and permitting of commercial-scale Carbon Capture, Utilization, and Storage projects." However, this need behind the program was not fully coordinated with the alternatives development process presented in the Draft EA. Instead, the NEPA document only explores the preferred Alternative and the No-Action Alternative because response to a funding application has been set as the Project purpose. This approach is discordant with the 2022 NEPA Implementing Regulations Revisions as the Council on Environmental Quality notes:

> "There may be times when an agency identifies a reasonable range of alternatives that includes alternatives—other than the no action alternative—that are beyond the goals of the applicant or outside the agency's jurisdiction because the agency concludes that they are useful for the agency decision maker and the public to make an informed decision. Always tailoring the purpose and need to an applicant's goals when considering a request for an authorization could prevent an

[1] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11

3

7-3 cont'd agency from considering alternatives that do not meet an applicant's stated goals, but better meet the policies and requirements set forth in NEPA and the agency's statutory authority and goals."[2]

7-4 This approach is further exclusionary of the types of lower-GHG emission alternatives mentioned above which may be more efficient at mitigating the effects of climate change if their lower emission rates result in fewer fugitive emissions during the power production and carbon sequestration process. EPA therefore recommends that the Draft EA expand on DOE's alternatives development process to consider any potential alternatives that may be less environmentally impactful than the preferred alternative while allowing for the advancement or carbon sequestration technology in the region. If other alternatives were not deemed practicable then we also recommend explaining why they were eliminated from detailed study in this segment.

Greenhouse Gas Analysis

The life cycle assessment (LCA) estimates GHG emissions for the plant from the extraction and transportation of the coal to the facility (i.e., upstream emissions), combustion of the coal and fuel (i.e., plant emissions), and the transmission of electricity along transmissions lines (i.e., downstream emissions of sulfur hexafluoride). The LCA also estimates carbon dioxide emissions captured by the Project from the combustion of coal and fuel (i.e., plant emissions); direct emissions from startup, shutdown, and malfunctions of the carbon capture system; and losses of carbon dioxide from transmission along the flowline to the carbon capture plant (i.e., fugitive emissions).

7-5 The analysis monetizes the climate damages associated with these GHG emissions using the Social Cost of Greenhouse Gases (SC-GHG) for the two alternatives presented in the Draft EA. Using the information provided, EPA was unable to replicate the SC-GHG values presented in Table 3-18. For transparency and replicability of results, we recommend providing a more detailed explanation of how the SC-GHG values were estimated and exactly which emissions are being valued. It would be helpful if the explanation clarifies the following:

- Whether the upstream emissions from coal and fuel extraction and transportation, and downstream emissions from electricity transmission, are the same in both scenarios.
- Whether the SC-GHG values for both scenarios include the social cost of other GHGs (e.g., methane and nitrous oxide).
- Whether the difference between the scenarios presented in Table 3-18 represents only the monetary damages of CO_2 emissions not captured by the Project under the No-Action Alternative.

7-6 We also recommend including the 95th percentile of estimates based on the 3% discount rate in Table 3.17 in addition to the 2.5%, 3%, and 5% discount rates already included. This fourth estimate would clarify the SC-GHG analysis presented in the Draft EA by making it consistent with the Interagency Working Group on SC-GHG's *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis* (86 Fed. Reg. 7037, January 20, 2021).[3]

[2] https://www.govinfo.gov/content/pkg/FR-2022-04-20/pdf/2022-08288.pdf
[3] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

4

Climate Change

7-7 Consistent with Executive Order 14008 – *Tackling the Climate Crisis at Home and Abroad* (86 Fed. Reg. 7619, January 25, 2021)[4] – the EPA recommends that DOE further discuss the climate pollution and benefits resulting from the proposed action. The LCA suggests the plant contributes 3.23 CO_2e per kg of CO_2 sequestered by the Project. This is largely due to incorporation of the emissions from transmission and distribution, which would occur with or without the Project (Table 3-6). The EPA recommends DOE remove these emissions from the scope of the LCA or provide a more robust discussion justifying significant investment in a project that generates roughly three kg of CO_2e for every one kg sequestered. In
7-8 addition to the LCA, we recommend using the CEQ's *National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions and Climate Change.*[5] The CEQ issued this interim guidance to assist Federal agencies in assessing and disclosing climate impacts during environmental reviews. Based on this guidance, we recommend addressing the following for each alternative in the EA:

- Estimate GHG emissions in CO_2-equivalent terms and translating the emissions into equivalencies that are more easily understood by the public (e.g., annual GHG emissions from x number of motor vehicles, see https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator).
- Include a detailed discussion of the preferred alternatives' GHG emissions in the context of state, national and international GHG emissions reduction goals, including the U.S. 2030 Paris GHG reduction target in addition to the 2050 net-zero pathway.[6] This discussion should address how reasonably foreseeable GHG emissions associated with the Project may support these policies and goals and over what timescale. While this information was partially represented for the No-Action Alternative, the proposed action did not get the same level of effective comparison to these goals in the Draft EA.

7-9 We further recommend evaluating the Project on its potential resiliency through climate change. Climate change may cause more extreme weather events which challenge existing infrastructure and can create points of failure. In order to more effectively communicate the climate change resiliency planning that has already been considered in the Draft EA, we also recommend making the Emergency Remediation and Response Plan mentioned in Appendix F publicly accessible and available for comment under the current NEPA development process.

Air Resources

7-10 The Milton R. Young power plant is a 705 MW plant with two units. The source is a major stationary source subject to permitting requirements, noted in the Draft EA. However, the details of existing air emissions and impacts as well as any necessary modifications to the permit have not been included in the Draft EA. Additionally the parasitic load of the carbon capture system is listed in the Draft EA as being 1836 MW, greater than the plant capacity. Therefore, we have included recommendations to assist in characterizing the project and disclosing existing impacts and to what degree those impacts would change should the project be implemented.

[4] https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad
[5] https://ceq.doe.gov/guidance/ceq_guidance_nepa-ghg.html
[6] https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

5

Project Specifications

7-11 The Draft EA states that implementation of the project will require 1836 MW of electricity consumption and 600 gigajoules per day (GJ/day) of steam (see page 3-6). The EA does not detail the equipment and specifications for all equipment that will contribute to this plant parasitic load. One of the largest energy usages may be CO_2 compression. Therefore, we recommend including the specifications and energy usage of equipment that will be major contributors to the parasitic load. We also recommend verifying the overall load, cited above, since it is greater than 705 MW plant capacity.

7-12 For steam consumption, we recommend explaining whether or not the modification would diminish plant steam available for turbine generation. To put the value of steam needed into context we recommend explaining what amount of steam is generated by the boilers at Milton R. Young in the same context (units of measure) as that used for the steam needed for the project. This additional information will be helpful when assessing the validity of the description of plant requirements as well as informing the lifecycle assessment of the project.

Existing Conditions

7-13 We recommend the Final EA include existing background concentrations that were used in the ND air quality modeling study discussed in the Draft EA for the modification to the plant (see page 3-3). These background concentrations serve as the basis for the existing air quality near the plant.

7-14 The plant is an existing major stationary source under the Clean Air Act, with air quality permits. While the Draft EA mentions the title V operating permit (see page 3-3), it does not include relevant information from the permit, or other New Source Review (NSR) permits that would be relevant to the existing air quality impacts at the plant, such as the plant Potential to Emit (PTE) and any air quality modeling for the existing plant configuration. We recommend that the current title V Operating Permit and Statement of Basis (SOB) be included as an appendix to the Final EA and further characterization of existing plant emissions be included in the Final EA.

Environmental Consequences

7-15 We recommend that the Final EA discuss what activities would be necessary to construct the project. Based on the necessary construction, we recommend generating an equipment roster and schedule. Based on the intensity of emission generating activity, it may be appropriate to develop an emission inventory in order to inform any potential emission reduction strategies for substantially contributing emitting units.

7-16 The Draft EA discloses that modeling has been conducted that considers the addition of the project (see page 3-3 and 3-4). However, the details of the modeling analysis are not included in the EA. Additionally, Table 3-2 does not include the modeling results or background concentrations, but rather includes the source parameter inputs for the modeling. We recommend including the modeling results and the location(s) (receptor(s)) associated with the results. Because modeling analyses can be quite complex, we recommend including supporting information related to the modeling analysis as an appendix to the Final EA.

7-17 We recommend comparing the existing emissions from the plant to the projected emission profile should the project be constructed. Any reduction in emissions at the plant due to increased control resulting from the carbon capture system should be noted.

6

September 19, 2023

VIA EMAIL

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236
Pierina.Fayish@netl.doe.gov

RE: Comments on the Draft Environmental Assessment for Project Tundra On Behalf of Sierra Club and CURE

Dear Ms. Fayish:

Sierra Club and CURE submit these comments on the draft Environmental Assessment (EA) for DOE/EA-2197: North Dakota CarbonSAFE: Project Tundra.

The Sierra Club is a national nonprofit organization with 67 chapters, including in North Dakota and Minnesota, and more than 832,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. In North Dakota, we have nearly 3,000 members and supporters; in Minnesota, we have nearly 57,000. Our goals include restoring clean air and water, providing affordable clean energy, supporting family-sustaining jobs, and addressing inequities in our response to climate disruptions. A key component of meeting this goal is achieving 80% carbon pollution-free electricity by 2030.

CURE is rural-based, with staff across Minnesota. CURE knows rural people, lands, and ecosystems are vital to helping solve some of the biggest problems faced by Minnesota and the nation. We help to tell the story of a vibrant rural future, lift-up people to lead, and work for policies and laws to make a better future possible for everyone. CURE's work includes a long-term focus on rural electric cooperative governance and evolution to advance a clean, healthy, and sustainable energy future. Minnkota Power Cooperative serves member co-ops in North Dakota and Minnesota, providing electricity to the rural Minnesotans that CURE hears from and works with on a regular basis. It is of paramount importance to CURE that the Department of Energy not shortchange these Americans with an inadequate environmental review.

I. Introduction

Project Tundra "would be the world's largest post-combustion CO2 capture and geologic storage
project," and includes a proposal to capture and permanently store CO2 emissions from
Minnkota's existing Milton R. Young Station, a lignite coal-fired power plant in Oliver County,
North Dakota.[1] The project consists of the carbon capture facility, a 0.5-mile-long CO2 flowline;
8-1 injection and disposal wells; and sequestration. And yet, despite the project's scale and multiple
self-evident impacts—from air pollution to water withdrawals—DOE's draft environmental
assessment (EA) inappropriately failed to conclude that an environmental impact statement (EIS)
is required. DOE defined the purpose and need statement so narrowly as to eliminate any
alternatives from consideration, in contravention of NEPA. The EA also has mischaracterized the
8-2 "no action" alternative by asserting, without basis, that without the DOE grant the Milton Young
plant will continue to operate at current levels for the next 20 years. In fact, the evidence
indicates that without the DOE funding, the plant would likely retire by 2035, resulting in a
100% reduction in its carbon emissions. When the "No Action" baseline is corrected, it is clear
that the carbon emissions impacts of pursuing Project Tundra would be significant. The EA also
8-3 overstates the project's efficacy. In fact, Project Tundra appears so poorly designed that it raises
questions as to whether it meets DOE's purpose and need of advancing carbon reductions, and
therefore should not even be considered a "feasible" alternative for NEPA purposes. The EA also
8-4 neglects to sufficiently address impacts to the Missouri River and surrounding communities from
the project's proposal to withdraw nearly 5 billion gallons of water. For all of these reasons, and
8-5 as further discussed herein, we recommend that DOE find that the environmental impacts of
Project Tundra would be significant, and therefore that an EIS is required before taking any
further steps to advance this project. The EIS should address all of the issues identified in these
comments.

II. The Agency Has Defined the Purpose and Need of This Project Too Narrowly, Blinding It to the Range of Appropriate Alternatives that Would be Better for the Environment.

8-6 The EA states that "[t]he purpose and need for DOE action is to advance the commercial readiness of CCUS by constructing a commercial-scale geologic storage complex and associated CO2 transport infrastructure" and to "further the development, deployment, and commercialization of technologies to capture and geologically store CO2 emissions securely in the subsurface." (1-3.) It further states that "Oliver County, North Dakota was proposed because a fully characterized storage complex: (1) is able to receive and safely store CO2 in sufficient quantities to meet the DOE goals of 50 million metric tons over a 30-year period; (2) is located in proximity to one or more CO2 sources that can supply those quantities; and (3) can be connected to the sources by a transport system that can be built and operated economically." This

[1] EA at 2-2.

2

8-6 cont'd purpose and need is so narrow and specific as to preclude from consideration all alternatives other than the Proposed Action, in contravention of NEPA requirements.[2]

8-7 First, the agency has constrained its analysis of better alternatives by limiting the purpose and need to the particular technology proposed by the applicant. While the agency must analyze the impacts for the proposed project, it does not need to fully constrain its analysis to one technology when the federal government is pursuing multiple pathways to advancing decarbonization.

Considering the broad purview of federal agencies' programs and policies to decarbonize the economy, it would be appropriate for DOE to expand its purpose and need statement to include analysis of any viable technology that would reduce carbon emissions from energy that would replace the current coal plant. As discussed further below, coal plants of similar age to Milton Young are increasingly uneconomic compared to portfolios of clean energy alternatives that can replace their energy, capacity and reliability benefits. DOE should consider whether incentivizing alternatives to Project Tundra would deliver far greater benefits for the amount of tax dollars spent.

This type of analysis of alternative generation sources would help inform both the agency and the public about better uses of federal funding under myriad other programs administered by DOE and other federal agencies, such as USDA. CEQ has stated that "Agencies have long considered myriad factors in developing a purpose and need statement. These include the agency's mission and the specifics of the agency decision, including statutory and regulatory requirements. Factors also may include national, agency, or other policy objectives applicable to a proposed action, such as a discretionary grant program targeted to achieve certain policy goals." CEQ Phase I regs, 2022.[3] But CEQ also makes clear that "There may be times when an agency identifies a reasonable range of alternatives that includes alternatives—other than the no action alternative—that are beyond the goals of the applicant or outside the agency's jurisdiction because the agency concludes that they are useful for the agency decision maker and the public to make an informed decision." *Id.* Here, it would be appropriate for DOE to adopt a broader purpose and need of advancing the goal of decarbonizing the economy in line with President Biden's commitments.

[2] The CEQ Phase I regulations further state: "It is contrary to NEPA for agencies to "contrive a purpose so slender as to define competing 'reasonable alternatives' out of consideration (and even out of existence)." *Simmons* v. *U.S. Army Corps of Engineers*, 120 F.3d 664, 666 (7th Cir. 1997) (citing 42 U.S.C. 4332(2)(E)). Constricting the definition of the project's purpose could exclude "truly" reasonable alternatives, making an EIS incompatible with NEPA's requirements. *Id. See also, e.g., Nat'l Parks & Conservation Ass'n* v. *Bureau of Land Mgmt.*, 606 F.3d 1058, 1070 (9th Cir. 2010) ("Agencies enjoy 'considerable discretion' to define the purpose and need of a project. However, 'an agency cannot define its objectives in unreasonably narrow terms.'" (internal citations omitted)).
[3] Available at https://www.federalregister.gov/documents/2022/04/20/2022-08288/national-environmental-policy-act-implementing-regulations-revisions

3

8-8 Moreover, the EA's purpose and need statement is too narrow even within the scope of advancing commercially viable carbon storage and sequestration. The EA states that "[t]he purpose and need for DOE action is to advance the commercial readiness of CCUS by constructing a commercial-scale geologic storage complex and associated CO2 transport infrastructure," and to "further the development, deployment, and commercialization of technologies to capture and geologically store CO2 emissions securely in the subsurface." (EA at 1-3.) But there are likely many other geologic areas and sources that are worthy of consideration, and that are likely to deliver far greater benefits in terms of advancing commercialization of carbon sequestration and storage.

DOE's funding could be better used to achieve the objective of "advanc[ing] the commercial readiness of CCUS and "further[ing] the development, deployment, and commercialization of technologies to capture and geologically store CO2 emissions securely in the subsurface" by pursuing CCS at other sources. It is widely accepted that it does not make economic sense to put billions of new dollars into old coal plants like Milton Young that are near the end of their design life. Plants like Milton Young are already likely more expensive to operate than cleaner alternatives, even before installing a technology that will make it even costlier to operate. For that reason, research models designed to examine the most cost-effective decarbonization pathways, such as the Princeton REPEAT study, indicate that most coal plants of Young's age should be retired rather than retrofitted with CCS.[4] In contrast, there are other sectors of the economy that many experts believe will require use of CCS in order to achieve decarbonization, such as certain types of heavy industry. At minimum, then, DOE should have evaluated whether it could better serve the goal of advancing decarbonization by seeking projects at the types of sources that are more likely to deploy CCS on a widespread basis. The EA impermissibly excludes such sources from consideration by circumscribing the purpose and need so narrowly that only this specific geologic formation and Milton Young meet its criteria.

8-9 A broader statement of purpose and need is particularly needed here, where the proposed Project is so poorly-designed that it is unclear whether it would even advance the narrow goal stated by DOE at all. As discussed in section III.B.3.c, below, the Project Tundra design is so questionable and shoddy that it appears unlikely to advance DOE's larger goal of commercializing carbon capture at coal plants, as it likely will not meet IRS standards to gain the tax credits necessary to make it financially viable. The EA should fully assess the opportunity-cost of funding a weak project design, namely Project Tundra, over saving this scarce public funding for a better proposal from a more reliable applicant.

DOE's funding for demonstration projects should not be used to prop up uneconomic designs for carbon capture. Both the agency and Project Tundra's own consultants assume that it would not

[4] Study results available at https://repeatproject.org/results?comparison=benchmark&state=national&page=1&limit=25#data

4

8-9 cont'd be built without significant support from DOE at this stage.[5] DOE should broaden the purpose and need to consider other alternatives that would more cost-effectively advance decarbonization goals, such as replacing the Young plant with clean energy. At minimum, the purpose and need should be expanded to other sources and geologic sites.

III. Project Tundra Will Have Significant Impacts on the Environment, and So Further Consideration Requires a Full Environmental Impact Statement.

A. The EA mischaracterizes the "no action" or "baseline" alternative, resulting in a flawed analysis of Project Tundra's comparative environmental impacts.

8-10 The EA wrongly assumes the baseline "no action" alternative would result in Young continuing to emit its current levels of carbon emissions, uncontrolled, until 2048. This assertion is without basis and is unsupported by the record. Rather, the evidence indicates that the "no action" alternative would result in the Young plant's retirement (closure) by no later than 2032, at which point its carbon emissions and (many other environmental impacts) would be eliminated. It also asserts that Project Tundra will reduce carbon emissions, when in fact the evidence shows it might actually increase them—even under DOE's faulty assumption that the No Action alternative would include operating Young until 2048.

DOE wrongly asserts that if Project Tundra is not funded, the Milton Young coal-fired power plant will continue to operate at its current levels, with its carbon emissions unabated, until 2048. (EA 3-1 and 3-54.) This assertion is arbitrary and lacks any evidentiary support.

It is entirely unrealistic and irrational to assume, as the EA does, that a coal plant that is already 50 years old will continue to operate for another 25 years. The average age of a coal plant when it is retired is 50.[6] Moreover, experts widely agree that most coal plants of Young's age in the United States are uneconomic compared to portfolios of clean energy alternatives such as wind, solar, and battery storage, which are plentiful in North Dakota and the surrounding states.[7] In the

[5] In a presentation last year to the National Association of Regulatory Utility Commissioners, Project Tundra consultant David Greeson said that "we're really counting on a demonstration grant from the Department of Energy." The DOE environmental assessment also found that Project Tundra likely "would not be constructed" without federal funding.
https://www.youtube.com/watch?feature=shared&t=1258&v=gaZpKtEetNQ.

[6] *See, e.g.*, Energy Information Administration (EIA), December 2021. Of the operating U.S. coal-fired power plants, 28% plan to retire by 2035. "Since 2002, around 100 GW of coal capacity has retired in the United States; the capacity-weighted average age at retirement was 50 years." *Available online at https://www.eia.gov/todayinenergy/detail.php?id=50658*

[7] *See, e.g.*, Energy Innovation, "Coal Cost Cross-Over 3.0," at 1-2 ("This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our

5

8-11 last decade, the capacity factors of coal plants have fallen substantially as lower cost renewables have come online.[8] The value of having pure "baseload" facilities has dropped markedly, particularly in high wind regions, such as North Dakota. Coal plants like Milton Young are cycling offline on a more regular basis in response to these changing economics, and thus are trending towards lower capacity factors. Coal plants have high operating costs and are inflexible compared to more modern, cleaner alternatives like portfolios of wind, solar and battery storage. Indeed, the grid operator for North Dakota and Minnesota, the Midcontinent Independent System Operator (MISO), states that "as wind capacity continues to grow, this may place increasing pressure on older, uneconomic baseload resources to cycle off overnight. It also will increase the value of having dispatchable conventional resources that can cycle on and off for much shorter periods."[9]

DOE must support its assertion that Milton Young will continue to operate at its current levels until 2048 with evidence. This evidence should include standard public utility industry modeling demonstrating that the plant is cost-competitive with replacement alternatives (such as portfolios of clean energy) and can be expected to operate at current levels until 2048. Without such analysis, the most reasonable assumption is that, without DOE funding, the plant will retire in the near future. Retirement would avoid not only 100% of future carbon emissions, but also would eliminate all other criteria air pollutants;[10] would entirely avoid water consumption at the plant; and would also indirectly reduce the impacts of the lignite mine associated with the plant. The EA does not account for any of these benefits, which must be addressed in an EIS.

8-12 Moreover, under draft 111(d) rules promulgated by the Environmental Protection Agency, it would be illegal for the plant to maintain its current operations through 2048 without carbon emissions controls starting no later than 2030. Under EPA's 111(d) proposed rule for existing coal plants, Milton Young would not be able to operate after 2039 unless it installed CCS technology and began capturing more than 90 percent of its carbon pollution in 2030.[11] Furthermore, coal plants retiring between the end of 2031 and the end of 2039 would be

two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace."). Available online at https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf

[8] *See, e.g.*, Energy Information Administration (EIA), September 2020. As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation. *Available online at* https://www.eia.gov/todayinenergy/detail.php?id=44976

[9] MISO. 2022 State of the Market Report, at 19. *Available online at* https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf

[10] See EA Table 3-2

[11] US EPA. Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Proposed Rule. May, 2023. *Available online at* https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf

6

8-12 cont'd obligated to start combusting at least 40 percent natural gas by heat input starting in 2030 unless they agree to limit their annual capacity factor to no more than 20% as of 2030, in which case they could operate at a business-as-usual emission rate through the end of 2034.

DOE admits that, without its funding, it is "likely" that "the commercial-scale CCUS project (Project Tundra) would not be constructed." (EA at 2-1.) At minimum, then, the baseline "no action" alternative should include retirement of Young no later than 2035 and a 20% capacity cap beginning in 2030, or retirement of Young no later than 2039 if the facility is willing to start burning at least 40% gas by 2030, which would entail substantially higher fuel costs for the facility and any necessary capital retrofits. DOE must revise the No Action alternative to reflect this.

8-13 Because the agency has misstated the baseline, it has wrongly concluded that Project Tundra will result in a significant reduction in carbon emissions compared to the "no action" alternative. When the baseline is corrected to assume retirement of Young by no later than 2035, it is apparent that the preferred alternative in fact would act as a life extension project and encourage more than a decade of additional carbon emissions (at a rate of at least 25-26 percent of the plant's carbon emissions, even if the technology works perfectly as designed) that would be avoided in the baseline scenario of earlier retirement. As discussed further in section III.B.2, below, this life extension can be expected to result in a net *increase* in emissions of between 9.4 and 12.7 million tonnes of CO2-equivalent, relative to closing the plant earlier.

Thus, the preferred alternative of funding Project Tundra will have significant impacts on the environment simply by increasing overall net carbon emissions in the atmosphere, requiring an EIS. The EA should be corrected to reflect an accurate baseline that is rooted in evidence and supported by analysis, and the environmental impacts should be updated to demonstrate the
8-14 significant likely harms caused by the preferred alternative. This includes updating the calculations of the Project's social cost of greenhouse gas emissions to reflect the significant climate damages likely to result from the Project.

B. The EA makes clear that Project Tundra will not have the environmental benefits claimed by DOE and in fact will result in an emissions increase; the Project is also so deficient that it is unreasonable to even consider it a "feasible alternative."

8-15 A close review of the EA shows that Project Tundra is likely to result in a significant emissions *increase* compared to the No Action alternative. Moreover, the EA repeatedly overstates the amount of carbon the project is likely to capture: it is only designed to capture, at most, 73% of emissions. At such a low capture rate, the Project is unlikely to qualify for the lucrative tax credits that are necessary to make the Project financially viable. It is therefore unclear whether the Project even is a "feasible alternative" that would advance DOE's CarbonSAFE

7

8-15 cont'd programmatic goal. At minimum, the Project will result in a significant impact to the environment via increased carbon emissions compared to the status quo, and so an Environmental Impact Statement is required.

1. **The Project Tundra Environmental Assessment fails to disclose that the greenhouse gas emissions of the resulting project will be worse than existing natural gas power plants.**

8-16 The EA for Project Tundra indicates that "construction of the project would result in an estimated net reduction in CO2 emissions (emissions that would otherwise be released to the atmosphere in the status quo scenario) of 4.0 million tpy over the anticipated operating life of the project."[12] As discussed elsewhere, this statement mischaracterizes the status quo scenario over the proposed life of the project. But in addition, it fails to follow CEQ guidance that NEPA documentation "should disclose and provide context for GHG emissions."[13] A critical element of disclosure and comparison with respect to a carbon capture project on an energy generation facility would be an equivalency to known power generation options. Following CEQ guidance, the Draft EA should have clearly specified that as proposed, Milton Young coal plant, as retrofitted with Project Tundra, would have a net emissions rate worse than that of a standard gas-fired power plant. This context is critically important for decision makers, both in assessing the value of investing government dollars in the project, and in assessing emissions outcomes.

Information in the EA shows that the project proponents estimate that Milton Young will produce between 5.8 and 6.3 million tons of CO_2 every year,[14] and "capture up to 4 million tons of CO2 on an annual basis."[15] Information presented in the Front End Engineering and Design (FEED) study presentation from May 2023 indicates that an average of 40% of generation and heat input at Milton Young will be consumed by the carbon capture retrofit.[16] Assessing the emissions remaining after capture and the net generation after consumption by the CCS island

[12] Draft EA at 3-6
[13] 88 FR 1202
[14] Following information available in Appendix F, converting from lignite consumption using heat content and the CO_2 content of coal. Details provided later in these comments.
[15] Draft EA at 3-6
[16] Department of Energy. Front-End Engineering & Design: Project Tundra Carbon Capture System. Virtual Closeout Meeting; Project DE-FE0031845. May, 22, 2023, at 20. *Available online at* https://netl.doe.gov/projects/files/Front-End%20Engineering%20and%20Design%20Project%20Tundra%20Carbon%20Capture%20System.pdf. 83.3 MWe of energy for auxiliary electricity consumption, plus 37,124 MMBtu/day of steam load, at a heat rate of 11.47 MMBtu/MWh (derived from Appendix F) reveals that Project Tundra will consume about 1.9 million MWh per year, or 38-41% of generation.

8

8-16 cont'd reveals an average emissions rate of approximately 0.55-0.60 tCO_2/MWh[17]—or worse than the stack emissions of a gas-fired power plant.[18]

This form of context, comparing the net emissions of this project to a widely known alternative generation source—is the type of context that is required under NEPA. These emissions are significant, and require DOE to conduct a full environmental impact statement.

2. **The EA mischaracterizes Project Tundra as capturing 95% of the entire flue stream from Milton Young, when it will in fact capture less than 75% of emissions.**

8-17 The EA incorrectly states, multiple times, that Project Tundra has a "design specification of at least 95 percent CO2 capture from the processed MRY [Milton Young] Unit 1 (250 megawatts gross [MWg] owned by Minnkota) and Unit 2 (455 MWg owned by Square Butte Electric) flue gas."[19] In fact, Project Tundra has been designed to capture less than 75% of Milton Young's carbon dioxide emissions, according to the project sponsors and the EA itself.

According to the project's proponents, Project Tundra is actually designed to capture around 74% of Milton Young's emissions,[20] a number that can also be derived from the EA. According to the EA and the project proponents, Project Tundra is expected to capture approximately 4 million metric tonnes of emissions per year, or an average of 73 percent of its projected generated emissions from 2028 to 2043, according to Appendix E (life cycle assessment) of the EA. Appendix E provides projected annual coal consumption (from 4-4.4 million tons of lignite per year),[21] lignite heating values for both units (13.09 and 13.23 MMBtu/short tons), and an emissions factor for coal (217.74 lb/MMBtu). From these factors, we can assess that the Milton

---

[17] Draft EA Appendix F (pdf page 186) indicates 2028 expected generation of 4.8 million MWh, less 1.9 million MWh of expected Project Tundra auxiliary load and steam load, resulting in net generation to grid of 2.9 million MWh. Using the heat content and emissions factor for coal as provided on the same page indicates an expected emissions generation of 6.0 million short tCO_2, less 4.4 million tons of capture per year (*see* Draft EA at 3-6, conversion to short tons), results in net stack emissions of 2 million short tCO_2. Taken together, in 2028, Milton Young, with the Project Tundra retrofit, would have a net emissions rate of 0.55 short tCO_2/MWh. In other years, the net emissions rate rises as high as 0.60 short tCO_2/MWh.
[18] According to EPA Clean Air Markets Program Data, the average stack emission rate for natural gas-fired combined cycle power plants was 0.43 short tCO_2/MWh in 2022, from a total of 602.7 million tons CO_2 and a gross generation of 1.386 billion MWh.
[19] Draft EA at 2-2. A similar statement appears at 3-6, "an LCA demonstrates the potential environmental impacts of capturing a minimum of 95 percent of unit-wide CO_2 emissions and storing the captured CO_2 in secure subsurface geologic formations."
[20] Minnesota Public Utilities Commission, Public Meeting. August 24, 2023. Docket ET6/RP-22-312. At 39 minutes. "...on station as a whole basis, it's about 74% reduction of CO_2 off the baseline, is what the design indicates." Available online at https://minnesotapuc.granicus.com/player/clip/2153?meta_id=237764&redirect=true&h=4d1e97b59e6cc16eb5a4aa0467ee8058
[21] Draft EA, Appendix F, pdf page 186

9

8-17 cont'd Young units will generate between 5.8 and 6.3 million tons of CO_2 every year.[22] Capturing 4.0 million metric tonnes per year, or 4.4 million short tons, would indicate that Project Tundra is projected to only capture 73 percent of CO_2 emissions.

Even from a design standpoint, the EA indicates that the carbon capture project at Milton Young is only designed to capture around 72 percent of emissions. Table 3-2 in the EA shows several different configurations of Project Tundra, where the first two cases indicate full capture on one unit, and partial capture on the other unit.[23] Assuming both units are fully operational, the cases show that Project Tundra could capture, at most, 73 percent of emissions.[24]

DOE has therefore overstated the carbon emissions reduction benefits of the proposed action—
8-18 and in fact, the Project is likely to result in a significant net *increase* in carbon emissions. As discussed in section III.A above, the project will effectively be extending the life of the Milton Young coal-fired power plant past its owners' assumed 2042 end-of-life (and beyond a likely 2035 retirement) until 2048. The emissions impact of this life extension with 73% carbon capture is entirely absent from the EA. By 2042, it is reasonable to assume that any replacement energy and capacity of Milton Young would be largely renewable and non-emitting. Therefore, if the EA were correct that with Project Tundra, Milton Young will operate until 2048 rather than 2042, then Project Tundra will result in an additional 13 million tons of CO_2 between 2043 and 2048, even if the CCS were operating at the expected level in the Draft EA.[25] Under the more reasonable assumption that the No Action alternative would result in Milton Young's retirement by 2035 and a 20% capacity factor between 2030-2035, the Proposed Action—and CCS operation through 2048—would result in a net emissions increase of 9.4 million tons relative to the No Action alternative.[26] Either way, the Proposed Action would result in a significant impact to the environment and requires an EIS. The EIS must correct the baseline No Action alternative to account for the likelihood of an earlier retirement date for the plant, and address the range of likely *increased* carbon emissions from moving forward with funding Project Tundra based on a capture rate of no more than 73 percent.

[22] For example, in 2023, 4.376 million tons of lignite represent a heat input of 57.68 million MMBtu, and therefore emissions of 6.28 million short tons CO_2.
[23] Draft EA at Table 3-2: Comparison of Air Quality Concentrations with Ambient Air Quality Standards
[24] Refer to "Case 1 - All U2 [Milton Young Unit 2] Partial U1 (25%)", or proportionally to the instantaneous output of each unit, 455 MW (U2) + 25% * 250 MW (U1) = 517 MW of flue gas of a 705 MW total plant is 73% of total output.
[25] From 2043 to 2048, assuming 3.5 million metric tons of capture per year (*see* Draft EA, Appendix F at 7), project Tundra would release approximately 2.1 million short tCO_2 per year, or 13 million tons over a 6 year period.
[26] The EA also includes a life cycle analysis that determined that "[t]here is an expected 3.23 kg of CO_2e emitted per kg of CO_2 stored." This point alone is a significant impact that requires an EIS.

10

3. The EA fails to account for the impact of the 45Q tax credit on Project Tundra's carbon capture lifetime, on the project's net greenhouse gas emissions, and on the Project's overall feasibility.

8-19 Fundamental to Project Tundra's financial viability is its ability to harvest a lucrative tax incentive, the 45Q tax credit for carbon dioxide sequestration.[27] And while the proponents are clearly aware of the importance of the tax credit to financing the project,[28] the EA fails to incorporate reasonable expectations about the impacts of that tax credit on the operations and lifetime emissions of the project. The EA also fails to assess the impact of carbon capture tax credits on increased operations at the coal plant, and fails to consider whether the project is appropriately designed to meet the statutory requirements of carbon capture tax credits that would allow the project to achieve operations.

a. The EA misstates the likely carbon capture lifetime of Project Tundra, mischaracterizing the project's greenhouse gas emissions reduction benefit.

8-20 The EA states that the proposed project will result in reduced greenhouse gas emissions, using multiple different assessments of the emissions reductions achieved. None of the assumptions are correct. The EA states that the life of the project will be 20 years,[29] from 2028 to 2048,[30] and that over that time period the project will either sequester 77.5 million tons[31] or 80 million tons.[32] The calculations are both based on faulty premises, and are inconsistent with the business

[27] Project Tundra. April 1, 2022. Virtual Briefing on Project Tundra. Provided to National Association of Regulatory Utility Commissioners (NARUC). *Available online at* https://www.youtube.com/watch?v=gaZpKtEetNQ. David Greeson, Development Lead for Project Tundra at 9:29. "In project tundra this one's a little simpler. We're going to be storing the CO_2, not using it in enhanced oil recovery. We're going to be depending on 45Q tax credits for a revenue stream, and the capture system is really the main thing that we're doing." *See also* at 18:33. "It's interesting to note that for 4 million metric tons per year when the tax credit gets to $50 that'll be $200 million a year of tax credits, and there's also some non-operating losses that the storage company can monetize for us and those add up to another $20-$30 million. So it's a lot of money just for one project; a lot of money changing hands here, but it's a structure that we think will work and allow us to raise the capital needed to move forward."

[28] *See* Project Tundra web site at https://www.projecttundrand.com/progress. "The project is currently seeking financial partners to help utilize existing 45Q federal tax credits, which are currently $85 per ton of CO_2 that is captured and stored in a geologic formation deep underground."

[29] Draft EA at Appendix F, page 1: "Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the
20 years of injection into two saline aquifer reservoirs."

[30] Draft EA at 3-54. "Therefore, this analysis calculates the SC-GHG from 2028 to 2048 (analysis lifespan).

[31] Draft EA at Appendix F, page 1.

[32] Draft EA at 3-6: "construction of the project would result in an estimated net reduction in CO_2 emissions (emissions that would otherwise be released to the atmosphere in the status quo scenario) of 4.0 million tpy over the anticipated operating life of the project." Over 20 years, 4.0 million tons per year results in 80 million tons sequestered.

8-20 cont'd proposition of Project Tundra, because they assume the project will operate continuously for 20 years.

8-21 The operations of Project Tundra are premised entirely on the continuous ability to receive the lucrative 45Q carbon capture credit, at $85 per metric tonne CO_2 captured and sequestered, over that 20 year period. However, the 45 Q credit is only available for a 12-year period.[33] After the exhaustion of that 12-year period and the expiration of the 45Q tax credit, capturing the carbon is so costly that continued operation is no longer financially viable at the plant. Of the expected $80.60/t$CO_2$ cost of capture,[34] at least $20.57/t$CO_2$ are incremental operational costs incurred to operate the carbon capture equipment.[35] Without the monetary incentive of the $85 per metric tonne CO_2 45Q credit, no rational operator would continue to incur excess costs not otherwise required by law or for safety and reliability. And since there is no evidence that Milton Young is needed for reliability or safety, it is unreasonable for DOE to assume the plant will continue to operate after the expiration of the tax credit.

In sum, even assuming that the project works flawlessly, it will result in just 12 years of carbon capture and sequestration, or from 2028 to 2040. Out of the 19 years of projected remaining life for the host power plant, through 2042,[36] Project Tundra would—at best—support 12 years of sequestration. DOE should revise its carbon capture estimates to reflect this.

b. The EA ignores the way in which the carbon capture tax credits will in fact incentivize *increased* operations (and emissions) at the Milton Young coal plant.

8-22 For purposes of calculating the amount of emissions the Project is likely to capture over 20 years, the EA assumes that Milton Young will maintain its current levels of operation.[37] This fails to account for how the lucrative 45Q tax credits will perversely incentivize an increase in the operations of the coal units at Milton Young, and must be corrected in DOE's analysis.

The 45Q tax credit is designed to help carbon capture projects both pay down the capital cost of expensive carbon capture projects, as well as subsidize the cost of operating the equipment. It is designed such that a producer is theoretically incentivized to capture as much as feasible, but is formulated as a production credit: a tax credit is awarded for the production of, and then capture and sequestration of, carbon dioxide. Because the tax credit is designed to pay down initial capital costs, it is a very large credit, and when applied to production costs, acts as an enormous incentive to increase operations. Accounting for the auxiliary (or parasitic) load requirements of

---

[33] 26 U.S. Code § 45Q(a)
[34] Department of Energy. Front-End Engineering & Design: Project Tundra Carbon Capture System. Virtual Closeout Meeting; Project DE-FE0031845. May, 22, 2023, at 11. *Available online at* https://netl.doe.gov/projects/files/Front-End%20Engineering%20and%20Design%20Project%20Tundra%20Carbon%20Capture%20System.pdf
[35] *Id*, at 35.
[36] *Id*, at 34.
[37] Draft EA at Appendix E, pdf page 186

12

8-22 cont'd carbon capture, a 90% capture facility awarded \$85/tCO_2 will generate nearly \$120 per megawatt-hour (MWh) of generation at a coal-fired power plant. For most coal plants, including Milton Young, the operational costs (even accounting for the carbon capture equipment) are far less than \$120/MWh, and thus the resulting net operating cost of the power plant falls to zero, or even well below zero. Accordingly, a coal-fired power plant with carbon capture equipment is incentivized to operate as often as feasible, a dynamic that is not accounted for in the Project Tundra EA.

This dynamic can be illustrated by looking at the operations of the Milton Young plant in 2022. In 2022, the two Milton Young units emitted 4.965 million short tons of CO_2 from their stacks,[38] of which Project Tundra would theoretically be able to capture 4.745 million tons, or 13,000 short tons CO_2 (stCO_2) per day.[39] However, in most days of 2022, Milton Young emitted far more than 13,000 stCO_2/d; if the project worked flawlessly, and Milton Young continued to operate exactly like it did in 2022, Project Tundra would have captured 3.917 million stCO_2.

But it is highly unlikely that Milton Young would operate as it did in 2022 if equipped with carbon capture—rather, Milton Young can be expected to operate *more* post-CCS installation. In 2022, Milton Young had 135 days (37% of the year) where it emitted <u>less</u> than 13,000 stCO_2 per day. In each of those days, operations post-installation of carbon capture would be financially inefficient, because the project owners would collect less tax credit than is optimal. The operators would be incentivized to minimize the number of days in which less than 13,000 tons of emissions were generated (in order to capture them), which would <u>increase</u> the operations of Milton Young relative to its already high output in 2022. The operators of the coal plant would also seek to reduce any days on which either unit of Milton Young was not operating in order to ensure that there was a continuous supply of carbon dioxide to the capture unit. This kind of increase in operations would result in a gross emissions increase, to which the 73% capture rate should then be applied. Increased operations can also be expected to increase emissions of co-pollutants like nitrogen oxide, sulfur dioxide and particulate matter, effluent, and toxic coal ash wastes while also increasing water consumption. The EA fails to account for any of these increases.

8-23 In addition, the EA assumes that in baseline conditions, the operations of Milton Young will remain high enough for the entirety of the analysis period that capture at the plant offsets any increased operations. In other words, the EA's assumption of an emissions benefit only makes sense if in the baseline, Milton Young is assumed to continue to exist <u>and</u> operate at an extraordinarily high level of output even if it were not retrofitted with carbon capture.

As discussed in section III.A above, this is an unreasonable and unjustified assumption. It is more reasonable to assume that under the No Action alternative, Milton Young will be retired by

[38] US EPA, Clean Air Markets Program Database. Hourly Emissions, 2022.
[39] Draft EA at 2-2 "The project would be designed to capture up to 13,000 short tons per day (STPD) of CO_2."

13

8-23 cont'd 2042 at the latest, but more likely by 2035 (with its capacity factor reduced to 20% between 2030-2035). In comparison, the Proposed Alternative of implementing carbon capture could further result in a net increase in emissions, particularly once the incentive to increase operations from the 45Q tax credit is accounted for. This phenomenon is discussed at length in comments by energy analysts in comments on 45Q, and must be addressed by DOE in its analysis.[40]

c. The EA ignores serious design problems with Project Tundra that call into question its financial viability and therefore its feasibility as an alternative.

8-24 Given the importance of the 45Q tax credit to the viability of Project Tundra, and therefore to the project's likelihood of leading to the transport and sequestration of CO_2, it is imperative for DOE to consider whether the project would even be eligible for this tax credit under the statutory requirements of 45Q. Using government funds to advance a project that will be financially infeasible based on its design specifications today is a waste of valuable taxpayer dollars.

At present, it appears questionable whether Project Tundra would actually meet the statutory requirements for 45Q eligibility. Under 26 USC §45Q(d)(2)(B)(ii), a 'qualified facility' (i.e. a carbon capture project) at an electricity generating facility must capture at least 18,750 metric tons of CO_2 per year and be designed to capture at least **75 percent** of historic (or 'baseline') emissions at the unit for which it was designed. Specifically, the text reads that "with respect to any carbon capture equipment for the applicable electric generating unit at such facility," the unit must have "a capture design capacity of not less than 75 percent of the baseline carbon oxide production of such unit."[41]

As described in section B2 above, it is clear that the project would achieve a total capture rate that does not meet this 75% statutory minimum. On August 18, 2023, Shannon Mikula, Special Projects Counsel for Minnkota, in response to a question from the Minnesota Public Utilities Commission, stated that "on a station as a whole basis, it's about a 74% reduction of CO_2 off the baseline, is what the design indicates." This statement, issued during the design phase of Project Tundra, would indicate that the capture design capacity of Project Tundra is less than the carbon oxide production of the electrical generating units to which it is attached - i.e., Milton Young coal plant. Such a failure at the design stage provides credible doubt that the project would qualify for the 45Q tax credit, and thus likely would be financially infeasible.

The proponents appear to argue that Project Tundra is designed to capture more than the statutory minimum of one unit, thereby providing it access to the tax credit, and the option to monetize additional capture. In proceedings before the Minnesota PUC, Minnkota argued that Project Tundra was designed around just one of Milton Young's coal units, and its ability to capture more than that unit's emissions provides the option to capture from either, or both, coal

[40] Treasury Docket IRS-2022-0028-0001. December 5, 2022. Comment from Synapse Energy Economics. https://www.regulations.gov/comment/IRS-2022-0028-0027
[41] 26 USC §45Q(d)(2)(B)(ii)

14

8-24 cont'd units. The Draft EA confirms this in Table 3-2, which shows several different possible configurations of Project Tundra. In one configuration (Case 1), Project Tundra would capture "all" of the emissions of the 455 MW Unit 2, and just 25% of the emissions of the 250 MW Unit 1; under a second configuration (Case 2), the project would capture "all" of Unit 1, and just 57% of Unit 2.

It is highly questionable whether the sizing and configuration proposed by the project proponents would actually meet statutory requirements of 45Q. Under one reading, the CCS equipment was clearly designed to capture emissions from both units, and therefore fails to capture the statutory minimum. Under a second reading, the CCS equipment, designed only to capture emissions from one unit, may not qualify for the 45Q credit for emissions captured from the second unit for which it was not designed.

8-25 Providing federal funding for a project that is only designed to capture a small fraction of a flue stream (the emissions from the second unit, at either 25% or 57% capture) is simply bad policy, both for Treasury and DOE. Because 45Q offers a substantial operational subsidy, the second unit from which CO_2 is captured would be heavily incentivized to operate, even under suboptimal market conditions, in order to generate the maximum 45Q subsidy. But a unit that only achieves 25% or 57% capture while incentivizing additional output is—under a wide variety of conditions—a net contribution of emissions, rather than a reduction of emissions. Taking into account the substantial parasitic load required to operate CCS equipment and the additional operations of the second coal unit, partial capture achieves little or no climate benefit, and would also result in substantial additional emissions of sulfur dioxide, oxides of nitrogen, heat and waste effluent, and coal ash. Such a configuration should not be subsidized by DOE. The EA fails to account for the expected net increase in carbon emissions and other criteria pollutant emissions from the second unit. These emissions impacts are significant and require conducting an EIS.

C. The EA overstates the environmental impacts of the No Action Alternative.

8-26 The EA asserts that under the No Action alternative, "Consequently, the commercial-scale geologic storage complex would not be constructed, and the risks would not be reduced for future storage complexes." (2-1.) But it does not follow that the failure of one bad proposal would doom either geologic storage of carbon in North Dakota or elsewhere. If not this project, perhaps one will come later that has better design or supportive policies, but there is no proof here that the failure of this project leads to a permanent failure of this technology or its use at this location.

Further, there is no evidence in the EA or elsewhere that this project's failure would negatively impact carbon emissions in the United States. Indeed, it is irrational for the EA to state that without the Project "[t]he President's goals of 50 to 52 percent reduction in GHG emissions from 2005 levels by 2030, a carbon pollution free power sector by 2035, and achieving a net-zero

15

8-26 cont'd GHG emissions economy by 2050 would not be advanced." (2-1.) Deciding not to fund the Project makes it more likely that this uneconomic coal plant will retire sooner, which would advance the President's overall GHG goals far more than installing a partly-functional capture system on it and continuing coal combustion and carbon emissions for decades down the road at the Project site.

D. The Impacts of Project Tundra on the Missouri River are Significant and Require an EIS, Particularly in Light of Significant Environmental Justice Concerns.

8-27 The project's impacts on water availability are significant. As the EA states, "A new water appropriation of 15,000 acre-feet from the Missouri River has been approved by the North Dakota State Water Commission to supply the water needs." (2-8) This is nearly **5 billion gallons** (specifically, 4,887,771,428.6 gallons) of water being drawn from the longest river in the United States, in an arid region that is frequently impacted by drought and other natural disasters.[42] Currently, about half of North Dakota is experiencing abnormally dry to extreme drought conditions,[43] but recent years have seen drought conditions worse than the Dust Bowl with untold negative impacts on the agricultural economy and natural resources.[44] Furthermore, ongoing multi-year drought in neighboring states[45] within the Missouri River watershed necessitates a full review of how this project's large new appropriation of water will affect the regional agricultural economy and downriver natural resources.[46] This review must consider the likelihood of worsening drought conditions in the region due to climate change. Considering the importance of continued access to the Missouri for agricultural and human uses, it is arbitrary and capricious to propose removing another 4.9 billion gallons of water from the river system without fully analyzing how this will affect other users.

8-28 These significant water impacts also necessitate an environmental justice impact review. Both Bismark and Standing Rock are downriver communities on the Missouri River. The EA ignores

[42] While potentially not as frequent of a disaster as drought, North Dakota also experiences significant flooding, which will occur more frequently due to climate change and will need to be discussed in the EA as regards how this plant and the water appropriation will function under such conditions. *See* https://www.weather.gov/safety/flood-states-nd.

[43] *See* North Dakota State University. Drought webpage and report. Last updated September 7, 2023. https://www.ndsu.edu/agriculture/ag-hub/ag-topics/disasters/drought

[44] National Public Radio. October 6, 2021. A mega-drought is hammering the U.S. In North Dakota, it's worse than the Dust Bowl. https://www.npr.org/2021/10/06/1043371973/a-mega-drought-is-hammering-the-us-in-north-dakota-its-worse-than-the-dust-bowl

[45] *See e.g.* Brownfield Agricultural News. December 12, 2022. Drought Still Top of Mind for Minnesota Cow/Calf Producers. https://brownfieldagnews.com/news/drought-still-top-of-mind-for-minnesota-cow-calf-producers/

[46] Minnesota farmers are experiencing severe drought and the overall watershed will not receive as much water as needed from Minnesota as a result of the ongoing multi-year drought. *See* Minnesota Public Radio. September 14, 2023. More than 5 million Minnesotans now live in the drought zone. https://www.mprnews.org/story/2023/09/14/over-5-million-minnesotans-now-live-in-the-drought-zone

16

8-28 cont'd the Project's impacts on water availability for downstream communities. The Summit pipeline, 8-29 discussed below, is also proposed to cross the river. DOE must address the cumulative impacts of this project on the Missouri for downstream environmental justice communities.

E. The EA fails to account for the cumulative impacts from the Project's connection to the Summit Pipeline.

8-30 The EA fails to acknowledge significant impacts that would result from this project's planned connection to the Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project (Summit pipeline). The EA states that the route for the Summit pipeline has a planned connection proximate to the Project Tundra sequestration site. The Summit pipeline is expected to be used to ship carbon dioxide to North Dakota for Enhanced Oil Recovery (EOR), a type of "carbon storage" that has significant impacts on the environment — namely, producing significantly more oil than would be available without carbon dioxide injection. North Dakota officials have made clear that they will not be able to continue producing oil without additional carbon dioxide pipelines such as the Summit pipeline, and that they need nearly ten times the currently-available carbon dioxide to continue EOR as planned.[47] Moreover, Summit's representatives, speaking in a regulatory proceeding in Iowa, recently confirmed that carbon dioxide shipped through the Summit pipeline can be used for EOR because Summit is merely a common carrier and it cannot prevent its shippers from using the material they ship for EOR.[48] As a result, the EA must address the high likelihood that this project's partnership with Summit will increase EOR in the state, and fully analyze the foreseeable impacts of that oil extraction. Additionally, to the extent that Project Tundra may accept or provide carbon dioxide for the Summit pipeline, the EA must further assess the anticipated land and water impacts of that pipeline, which will be made more likely to occur as a result of the funding that the agency proposes to provide here.

8-31 Secondly, the EA incorrectly describes Summit's application status before state regulators as having one "pending application" for the Summit pipeline in North Dakota. In reality, Summit has seen all of its applications (both for the pipeline and with local authorities regarding construction at injection well sites) rejected by the relevant authorities — the company has since

[47] KFYR TV News. August 16, 2023. North Dakota Department of Mineral Resources warns more CO2 needed to sustain oil production long-term. https://www.kfyrtv.com/2023/08/16/north-dakota-department-mineral-resources-warns-more-co2-needed-sustain-oil-production-long-term/ ("State Department of Mineral Resources Director Lynn Helms . . . . said the state needs to get the gas from somewhere to help with enhanced oil recovery. The emerging technology uses CO_2 and other materials to help producers to take more oil than traditional methods. Helms said current CO_2 production only meets about 10 percent of what is needed for enhanced oil recovery.")

[48] Agweek News. September 5, 2023. Summit Carbon Solutions leaves open transporting CO_2 for oil wells https://www.agweek.com/news/policy/summit-carbon-solutions-leaves-open-transporting-co2-for-oil-wells

17

8-31 cont'd asked North Dakota's pipeline regulator to reconsider,[49] but it does not have a "pending" application at this point. It is more accurate to say that it was denied permits to operate and it is attempting to overturn those decisions.

8-32 The fact that Project Tundra's apparent back-up plan for carbon shipping or sequestration/utilization increasing seems to have no viable project in North Dakota should be discussed and assessed in the EA. To the extent that the Summit pipeline is never built, the EA should assess the potential impacts of Project Tundra capturing large amounts of carbon dioxide with nowhere to go with it. Providing tens of millions of dollars in public funding for a project with no clear end point for injection is the definition of wasteful bureaucracy, and should be avoided through full and accurate analysis of the potential failure to obtain permits that is strongly suggested by the recent history of the Summit company in North Dakota.

IV. Conclusion

For the reasons identified herein, the impacts of Project Tundra would be significant, and DOE must conduct a full EIS before moving forward.

Respectfully submitted,

/s/ Hudson Kingston
Hudson B. Kingston
Legal Director
CURE, https://curemn.org/
117 S 1st Street
Montevideo, MN 56265
(320) 269-2984
hudson@curemn.org

/s/Laurie Williams
Laurie Williams
Senior Attorney
Sierra Club
1536 Wynkoop, Suite 200
Denver, CO 80202
Tel: (303) 454-3358
laurie.williams@sierraclub.org

[49] Agweek News. August 19, 2023. Summit Carbon Solutions asks North Dakota to reconsider pipeline route denial, seeks new path around Bismarck. https://www.agweek.com/news/policy/summit-carbon-solutions-asks-north-dakota-to-reconsider-pipeline-route-denial-seeks-new-path-around-bismarck

18

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 18, 2023

Pierina Fayish
NEPA Compliance Officer
Dept. of Energy, National Technology Laboratory
626 Cochran Mill Rd.
Pittsburgh, PA 15236

Re: Project Code: DOE/EA-D2197, Project Tundra Draft Environmental Assessment in Oliver County

Dear Ms. Fayish:

The North Dakota Department of Environmental Quality has reviewed the information concerning the above-referenced project received at the department on August 21, 2023, with respect to possible environmental impacts.

9-1 1. Care is to be taken during construction activity near any water of the state to minimize adverse effects on a water body. This includes minimal disturbance of stream beds and banks to prevent excess siltation, and the replacement and revegetation of any disturbed area as soon as possible after work has been completed. Caution must also be taken to prevent spills of oil and grease that may reach the receiving water from equipment maintenance and/or the handling of fuels on the site. Guidelines for minimizing degradation to waterways during construction are attached.

9-2 2. Projects disturbing one or more acres are required to have a permit to discharge stormwater runoff until the site is stabilized by the re-establishment of vegetation or other permanent cover. Further information on the stormwater permit may be obtained from the department's website or by calling the Division of Water Quality at 701-328-5210. Also, cities may impose additional requirements and/or specific best management practices for construction affecting their storm drainage system. Check with the local officials to be sure any local stormwater management considerations are addressed.

9-3 Minnkota Power Cooperative, Inc. (Minnkota) must notify the North Dakota Pollutant Discharge Elimination System (NDPDES) Program in advance of any planned changes at Milton R. Young Station due to Project Tundra which may affect current and future NDPDES permits for the facility (ND-000370 and NDR05-0012). This includes facility expansions, production increases, and process modifications which result in new, different, or increased discharges of pollutants. In particular, Minnkota must work with the NDPDES Program to determine what effects the amine-based post-combustion carbon capture, ultra-filtration, and nano-filtration technologies will have on Nelson Lake, Square Butte Creek, and/or other receiving streams, and how changes to the Missouri River intake structure

918 East Divide Avenue | Bismarck ND 58501-1947 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 | Division of Air Quality 701-328-5188 | Division of Municipal Facilities 701-328-5211 | Division of Waste Management 701-328-5166 | Division of Water Quality 701-328-5210 | Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

Pierina Fayish 2 September 18, 2023

9-3 (cont'd.) could affect impingement and entrainment requirements. Changes which may result in a facility being designated as a "new source" as determined by 40 CFR 122.29(b) must also be reported to the NDPDES Program.

9-4 3. The construction project does not overlie a defined surficial aquifer; however, it does overlie a non-community well protection area. Care should be taken to avoid spills of any materials that may have an adverse effect on groundwater quality. All spills must be immediately reported to this Department and appropriate remedial actions performed.

9-5 4. The proposed project appears to have the potential to be a source of emissions to the air capable of causing or contributing to air pollution and may be required to have an Air Pollution Control Permit to Construct/Operate as required by Chapter 33.1-15-14 of the North Dakota Air Pollution Control Rules. The applicant should contact the department's Air Pollution Control Program at 701-328-5188 prior to commencing construction.

9-6 5. All solid waste materials must be managed and transported in accordance with the state's solid and hazardous waste rules. Appropriate efforts to reduce, reuse and/or recycle waste materials are strongly encouraged. As appropriate, segregation of inert waste from non-inert waste can generally reduce the cost of waste management. Further information on waste management and recycling is available from the department's Division of Waste Management at 701-328-5166.

9-7 6. Projects that involve construction of pipelines should select locations that minimize the potential for impacts to human health and the environment during and after construction by avoiding, when possible, source water protection areas and sensitive surface and groundwater environments. Additionally, when possible, pipeline routes should select areas with natural barriers to both surface and ground waters. Human health and the environment
9-8 should be further protected by developing a spill response plan that emphasizes rapid deployment of prepositioned assets necessary to contain spills and subsequent cleanup. Proper surveillance and monitoring for early detection of leaks should be required.

Division of Waste Management – UST Program

9-9 The department's UST Program does have historical underground storage tanks within the Tundra (Milton R. Young Station/Minnkota Power Coop) facility in Center, ND. (See attachment.)

If the construction or demolition will require the removal, installation or replacement of any UST system (tanks, piping or associated components) or the reporting of any release, it will need to follow the TECHNICAL STANDARDS AND CORRECTIVE ACTION REQUIREMENTS FOR OWNERS AND OPERATORS OF UNDERGROUND STORAGE TANKS, CHAPTER 33.1-24-08 regarding notification, installation, closure and compliance. The regulations can be found at https://www.legis.nd.gov/information/acdata/pdf/33.1-24-08.pdf

Pierina Fayish 3 September 18, 2023

9-10 These comments are based on the information provided about the project in the above-referenced submittal. The U.S. Army Corps of Engineers may require a water quality certification from this department for the project if the project is subject to their Section 404 permitting process. Any additional information which may be required by the U.S. Army Corps of Engineers under the process will be considered by this department in our determination regarding the issuance of such a certification.

The department owns no land in or adjacent to the proposed improvements, nor does it have any projects scheduled in the area. In addition, we believe the proposed activities are consistent with the State Implementation Plan for the Control of Air Pollution for the State of North Dakota.

If you have any questions regarding our comments, please feel free to contact this office.

Sincerely,

L. David Glatt, P.E., Director
North Dakota Department of Environmental Quality

LDG:ll
Attach.

Construction and Environmental Disturbance Requirements

The following are the minimum requirements of the North Dakota Department of Environmental Quality for projects that involve construction and environmental disturbance in or near waters of the State of North Dakota. They ensure that minimal environmental degradation occurs as a result of construction or related work which has the potential to affect waters of the state. All projects must be constructed to minimize the loss of soil, vegetative cover, and pollutants (chemical or biological) from a site.

9-11 **Soils**

Prevent the erosion and sediment loss using erosion and sediment controls. Fragile and sensitive areas such as wetlands, riparian zones, delicate flora, and land resources must be prohibited against compaction, vegetation loss and unnecessary damage.

9-12 **Surface Waters**

All construction must be managed to minimize impacts to aquatic systems. Follow safe storage and handling procedures to prevent the contamination of water from fuel spills, lubricants, and chemicals. Stream bank and stream bed disturbances must be contained to minimize silt movement, nutrient upsurges, plant dislocations, and any physical chemicals, or biological disruption. The use of pesticides or herbicides in or near surface waters is allowed under the department's pesticide application permit with notification to the department.

9-13 **Fill Material**

Any fill material placed below the ordinary high-water mark must be free of topsoil, decomposable materials, and persistent synthetic organic compounds, including, but not limited to, asphalt, tires, treated lumber, and construction debris. The department may require testing of fill material. All temporary fills must be removed. Debris and solid waste must be properly disposed or recycled. Impacted areas must be restored to near original condition.

Facility Form Report

Tuesday, September 5, 2023

Facility Information

Name	Minnkota Power Cooperative Inc	**ID**	46
Sub Name	Milton R Young Station	**EPA ID**	
Address	3401 24th St SW	**PTRCF ID**	447
Address 2	Box 127	**Latitude**	47.068796
City State Zip	Center ND 58530 -	**Longitude**	-101.218347
County	Oliver	**Collection Method**	Address Matching
Phone	(701) 794-8711	**Reference Point**	Entrance Point
Region	4	**Facility Directory**	46
UST Status	Inactive	**Facility Profiler ID**	3384
LUST Standing	Inactive	**Mail Delivered To**	Facility
Archived	☐	**Notification Rec**	02/26/1990
		DSR Hard Copy	☐

Type of Owner

Type	Commercial **ID** 1276
Owner	Minnkota Power Cooperative Inc
Address	5301 32nd Avenue South
City State Zip	Grand Forks ND 58201-

Indian Lands

Indian Lands ☐
Tribe Owned ☐
Tribe

Type of Facility

Describe the kind of facility Utilities
SIC Codes 4939
NAICS Codes 221

Dispenser Information:
☐ Single Hose Dispenser
☐ Credit Card/Cardtrol Only
☐ No Retail Sale
☐ Blender Pump

Comments

Financial Responsibility

Financial responsibility requirements met for less than 100 tanks / $1 million ☑

Self-Insured	☑	**State Fund**	☑
Insurance	☐	**Letter of Credit**	☐
Risk Retention Group	☐	**Trust Fund**	☐
Guarantee	☐	**Other**	☐
Surety Bond	☐	**Not Listed**	☐
Federal Governement	☐	**Railroad**	☐

Comments #447

Financial responsibility requirements met for more than 100 tanks / $2 million ☐

Self-Insured	☐		
Insurance	☐	**Letter of Credit**	☐
Risk Retention Group	☐	**Trust Fund**	☐
Guarantee	☐	**Other**	☐
Surety Bond	☐	**Not Listed**	☐
Federal Government	☐	**Railroad**	☐

FR Agency
FR Policy No
FR Exp Date
Comments

Certification

Name John T Graves **Title** Environmental Supervisor **Date** 12/17/1991

Tank

Number:	1	Tank Status:	Permanently Out of Use	Compartments:	1	Date Installed:	10/6/1984
Alt ID:	1	Total Capacity:	10000				
Material:	Fiberglass Reinforced Plastic			Secondary Material:	None		

Federally Regulated ☑ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment: 1 Capacity: 10000 Substance: Gasoline

Pipe Material: Fiberglass Reinforced Plastic - None Pipe Type: Pressurized

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☑		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☑
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☑	Not listed	☐	☐

Number: 2 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/15/1969

Alt ID: E-7 Total Capacity: 15000

Material: Asphalt Coated or Bare Steel Secondary Material: None

Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment: 1 Capacity: 15000 Substance: Heating Oil

Pipe Material: Unknown - None Pipe Type: Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 3 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/15/1969

Alt ID: E-8 Total Capacity: 15000

Material: Asphalt Coated or Bare Steel Secondary Material: None

Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment: 1 Capacity: 15000 Substance: Heating Oil

Pipe Material: Unknown - None Pipe Type: Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 4 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-2 Total Capacity: 2000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 2000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 5 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-3 Total Capacity: 6000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 6000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 6 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-4 Total Capacity: 550
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 550 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 7 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-5 Total Capacity: 1000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 1000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 8 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-6 Total Capacity: 2000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 2000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 9 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1969
Alt ID: R-9 Total Capacity: 280
Material: Asphalt Coated or Bare Steel Secondary Material: None
Federally Regulated ☑ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 280 Substance Diesel
Pipe Material Copper - None Pipe Type Safe Suction

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☑		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☑	Not listed	☐	☐

Number: 10 | Tank Status: Currently In Use | Compartments: 1 | Date Installed: 1/1/1992
Alt ID: A10 | Total Capacity: 1000
Material: Not Listed | Secondary Material: None
Federally Regulated ☐ | AST ☑ | Compartment ☐ | Manifolded ☐ | Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 | Capacity 1000 | Substance Diesel
Pipe Material Not Listed - None | Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 11 | Tank Status: Currently In Use | Compartments: 1 | Date Installed: 1/1/1992
Alt ID: A-11 | Total Capacity: 500
Material: Not Listed | Secondary Material: None
Federally Regulated ☐ | AST ☑ | Compartment ☐ | Manifolded ☐ | Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 | Capacity 500 | Substance Gasoline
Pipe Material Not Listed - None | Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 12 | Tank Status: Currently In Use | Compartments: 1 | Date Installed: 1/1/1992
Alt ID: A-12 | Total Capacity: 500
Material: Not Listed | Secondary Material: None
Federally Regulated ☐ | AST ☑ | Compartment ☐ | Manifolded ☐ | Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 | Capacity 500 | Substance Gasoline
Pipe Material Not Listed - None | Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 13 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A13 Total Capacity: 300
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 300 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 14 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-14 Total Capacity: 30000
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 30000 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 15 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-15 Total Capacity: 280
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 280 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 16 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-16 Total Capacity: 280
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 280 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line eak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Dispenser

Number	1	Status / Construction of UDC	
Alternate ID	1/2	Installation Date	
Dispenser Status	Currently In Use	Closure Date	
UDC	No	Total Capacity	0
Received Date		Material	
Comments		Secondary Material	None
		Material Comments	

Release Detection UDC — UDC
Interstit. Dbl-wall Monitor ☐
UDC Tightness Testing ☐
Release Comments

UDC Meets 2009 N.D.A.C Requirements ☐
Single Hose Dispenser ☐
Credit Card / Cardtrol Only ☐
Blender Dispenser ☐
Satellite Dispenser ☐

Contacts

Name/ Address	City State Zip/ Phone	Email/ Status	Operator	Manager	Outreach	Corrective	DSR	Location	Other
Mr. Scott C Hopfauf 3401 24 St SW	Center ND 58530- 7017947220	shopfauf@minnkota.com Active	☑	☐	☐	☐	☑	☐	☐
Tony J Aman PO Box127	Center ND 58530- 7017947237	taman@minnkota.com Active	☑	☐	☐	☐	☐	☐	☐
Kevin Thomas 3401 24th St SW	Center ND 58530- 7017947278	kthomas@minnkota.com Inactive	☐	☐	☐	☐	☐	☐	☑ Plant Super
Mr Mike A Tietz 3401 24th St SW	Center ND 58530- 7017947266	MTietz@minnkota.com Inactive	☐	☐	☐	☐	☐	☐	☑ Permitting & Compliance En

Testing

	Test Type	Date	Company	Docs Received	Result
Tank: 1 Comp: 1	Tightness	09/29/2009		☑	Pass
	Tightness	09/29/2009		☑	Pass
	Tightness	10/11/2012	Valley Electric & Petroleum Equip	☑	Pass
	Tightness	10/11/2012	Valley Electric & Petroleum Equip	☑	Pass

Tightness	10/16/2013		☑	Pass
Tightness	10/16/2013		☑	Pass
Tightness	10/19/2015	Valley Electric & Petroleum Equip	☑	Pass
Tightness	10/19/2015	Valley Electric & Petroleum Equip	☑	Pass
Tightness	10/18/2016	Valley Electric & Petroleum Equip	☑	Pass
Tightness	10/18/2016	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/27/2017	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/27/2017	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/17/2020	Tanknology	☑	Pass
LLD	09/17/2020	Tanknology	☑	Pass
LLD	09/17/2020	Tanknology	☑	Pass
Tightness	09/17/2020	Tanknology	☑	Pass

LUST

Date	Current Status	How Found	Reporting Party	Inspector	Comment
12/17/1991	Site Cleanup Complet		David J Swillick	David Swlick	Contaminated Soil was Removed; Amount = 5; City = Center; Land Farm;

Fuel Sample

Correspondence

Type Date	Compliance	Fuel Sample	Inspection	LUST	DSR	Staff Contact	RE File	Dept Initiated	Description
Reports 05/20/2021	☐	☐	☑	☐	☐	LeonVetter Stephanie	UST 46 Inspection Report UST 46 20210518 Closure Inspection.pdf	☑	Filed Inspection Report
EMail 01/01/2021	☐	☐	☐	☐	☐	System COC Contact	Testing Reminder Email UST 46 20210406 Reminder Email.pdf	☑	ram Region #4– UST system testing OVERDUE – Enforc
QuickNote 11/18/2020	☐	☐	☐	☐	☐	LeonVetter Leon Vetter	UST 46 20201118 QuickNote UST 46 20201118 QuickNote.pdf	☐	Water in tank
EMail 10/01/2020	☐	☐	☐	☐	☐	System COC Contact	Testing Reminder Email UST 46 20201016 Reminder Email.pdf	☑	ram Region #4– UST system testing OVERDUE
Email 07/08/2020	☐	☐	☐	☐	☐	LeonVetter Tony J Aman	UST 46 UST 46 20200708 Compliance Inspection Email.pdf	☐	Sent Compliance Inspection Request Email
Email 05/21/2020	☐	☐	☐	☐	☐	LeonVetter Scott C Hopfauf	UST 46 UST 46 20200521 Compliance Inspection Email.pdf	☐	Sent Compliance Inspection Request Email
DSR 02/27/2020	☐	☐	☐	☐	☐	LeonVetter Kevin Thomas	UST 46 UST 46 20200227 COC Doc1.pdf	☐	Received 2019 COC Supporting Documents
DSR 02/27/2020	☐	☐	☐	☐	☑	LeonVetter Kevin Thomas	UST 46 UST 46 20200227 COC Certificate.pdf	☐	Sent 2019 COC Certificate
Letter 01/17/2020	☐	☐	☐	☐	☑	LeonVetter Kevin Thomas	COC Questionnaire - 2019	☑	Sent COC Form (System) 2019
EMail 11/01/2019	☐	☐	☐	☐	☐	System COC Contact	Testing Reminder Email UST 46 20191105 Reminder Email.pdf	☑	ram Region #4– UST system testing OVERDUE

Reports 11/01/2019	☐ ☐ ☐ ☐ ☐	Robin A Schiermeister Thomas Mortrud	UST 46 20191101 2019 MLLD And ELL UST 46 20191101 2019 MLLD And ELLD Test 74715.pdf	☐ 2019 MLLD And ELLD Test
EMail 10/01/2019	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20191002 Reminder Email.pdf	☑ UST system testing OVERDUE
EMail 07/01/2019	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20190703 Reminder Email.pdf	☑ UST system testing DUE
DSR 02/12/2019	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20190212 COC Doc1.pdf	☐ Received 2018 COC Supporting Documents
DSR 02/12/2019	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20190212 COC Certificate.pdf	☐ Sent 2018 COC Certificate
Letter 01/14/2019	☐ ☐ ☐ ☐ ☑	LeonVetter Scott C Hopfauf	COC Questionnaire - 2018	☑ Sent COC Form (System) 2018
EMail 01/01/2019	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20190102 Reminder Email.pdf	☑ UST system testing DUE
Reports 09/26/2018	☐ ☐ ☐ ☐ ☐	Carl E Ness	UST 46 20180926 Line Tightness and UST 46 20180926 Line Tightness and MLD tests 65102.pdf	☐ Line Tightness and MLD tests
Email 07/19/2018	☐ ☐ ☐ ☐ ☐	DaveCameron Scott Hopfauf	Approve Operator Updates	☑ Sent Approve Operator Updates Email
DSR 03/15/2018	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20180315 COC Certificate.pdf	☐ Sent 2017 COC Certificate
EMail 02/01/2018	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20180201 Reminder Email.pdf	☑ UST system testing OVERDUE – Enforcement action
Letter 01/26/2018	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	COC Questionnaire - 2017	☑ Sent COC Form (System) 2017
EMail 11/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20171101 Reminder Email.pdf	☑ UST system testing OVERDUE
EMail 10/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20171002 Reminder Email.pdf	☑ UST system testing DUE
Complnc Test 09/27/2017	☐ ☐ ☐ ☐ ☐	LeonVetter	UST 46 20170927 LTT and ALLD tests UST 46 20170927 LTT and ALLD tests 52368.pdf	☐ LTT and ALLD tests
Complnc Test 09/25/2017	☐ ☐ ☐ ☐ ☐	LeonVetter	UST 46 20170925 LTT results 50893.p UST 46 20170925 LTT results 50893.pdf	☐ LTT results
EMail 09/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20170901 Reminder Email.pdf	☑ UST system testing DUE
EMail 08/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20170801 Reminder Email.pdf	☑ UST system testing DUE
DSR 02/21/2017	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20170221 COC Doc1.pdf	☐ Received 2016 COC Supporting Documents
DSR 02/21/2017	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20170221 COC Certificate.pdf	☐ Sent 2016 COC Certificate
Letter 02/03/2017	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	COC Questionnaire - 2016	☑ Sent 2016 COC Form (System)
Complnc Test 10/18/2016	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 20161018 ltt and atg resutls.pdf	☐ ltt and atg resutls
EMail 10/01/2016	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20161005 Reminder Email.pdf	☑ UST system testing DUE
EMail 09/01/2016	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20160907 Reminder Email.pdf	☑ UST system testing DUE

EMail 08/01/2016	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20160907 Reminder Email.pdf	☑ UST system testing DUE
DSR 02/19/2016	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20160219 COC Doc1.pdf	☐ Received 2015 COC Supporting Documents
DSR 02/19/2016	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20160219 COC Certificate.pdf	☐ Sent 2015 COC Certificate
Letter 02/03/2016	☐ ☐ ☐ ☐ ☑	dohustowner Kevin Thomas	COC Questionnaire - 2015	☑ Sent COC Form (System) 2015
Email 08/20/2015	☐ ☐ ☐ ☐ ☐	LeonVetter Mike Tietz	Approve New Operator	☑ Sent Approve New Operator Email
DSR 03/16/2015	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20150316 COC Doc1.pdf	☐ Received 2014 COC Supporting Documents
DSR 03/16/2015	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20150316 COC Certificate.pdf	☐ Sent 2014 COC Certificate
Letter 03/02/2015	☐ ☐ ☐ ☐ ☑	DOHUSTowner Kevin Thomas	COC Questionnaire - 2014	☑ Sent COC Form (System) - 2014
DSR 08/25/2014	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20140825 COC Doc1.pdf	☐ Received 2013 COC Supporting Documents
DSR 08/25/2014	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20140825 COC Doc2.pdf	☐ Received 2013 COC Supporting Documents
Letter 08/06/2014	☐ ☐ ☐ ☐ ☑	CarlNess Craig Bleth	COC Questionnaire - 2013	☑ Sent COC Form (System) 2013
Maps 04/19/2013	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 20130419 site map google earth.jpg	☐ site map google earth
Other 03/08/2013	☐ ☐ ☐ ☐ ☑	Leon J Vetter	UST 46 UST 46 20130308 2012 COC.pdf	☐ 2012 COC
Letter 02/22/2013	☐ ☐ ☐ ☐ ☑	DOHUSTOwner Craig Bleth	COC Questionnaire - 2012	☑ Sent 2012 COC Form (System)
Email 07/11/2012	☐ ☐ ☐ ☐ ☐	LeonVetter Tony Aman	Approve New Operator	☑ Sent Approve New Operator Email
Email 07/11/2012	☐ ☐ ☐ ☐ ☐	LeonVetter Scott Hopfauf	Approve New Operator	☑ Sent Approve New Operator Email
Other 06/27/2012	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 20120627 2011 COC and documents.pdf	☐ 2011 COC and documentation
Letter 07/29/2011	☐ ☐ ☐ ☑ ☐	Leon J Vetter	UST 46 UST 46 20110729 ltr.pdf	☐ petroleum contaminated soil
Other 02/08/2011	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 20110208 Various documents UST 46 20110208 Various documents 1984 -2011 87418.pdf	☐ Various documents 1984 -2011
Reports 09/20/1994	☐ ☐ ☐ ☐ ☐	Alison Harries	UST 46 19940920 WQ Release Summa UST 46 19940920 WQ Release Summary Report 84470.pdf	☐ WQ Release Summary Report
Other 08/03/1994	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 19940803 suspected release.pdf	☐ UST suspected release
Reports 12/17/1991	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 19911217 UST removal report with associated documents.pdf	☐ UST removal report and associated documents
Notification 12/17/1991	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 19911217 SFN 10980 Notification Form.pdf	☐ SFN 10980 Notification Form

Inspections

Date	Type	Inspector	Contact	Comment

05/18/2021	Closure	Leon Vetter	Stephanie	
07/16/2020	Routine	Leon Vetter		Had all LD records. Spill/overfill good. CP good. They are thinking of removing tank.
09/27/2016	Routine	Leon Vetter	Scott Hopfauf	Have flapper valve in drop tube.
09/25/2013	Routine	Leon Vetter	Scott Hopfauf	Had all records. Pump in uncontained sump.
05/24/2010	Routine	Carl Ness	Scott Hopfauf	
06/22/2006	Routine	Carl Ness	Not Entered	Inp Carl

Compliance

History

Date From Date To	Facility Name Facility Location	Description
03/23/2011	(1276) Minnkota Power Cooperative Inc - (46) Minnkota Power Cooperative Inc 3401 24th Street SW, Center ND 58530	System Conversion

LUST Form Report

Tuesday, September 5, 2023

Facility Name Minnkota Power Cooperative Inc
Address 3401 24th St SW
City State Zip Center, ND 58530-
Phone (701) 794-8711 **Facility ID** 46
Comments Contaminated Soil was Removed; Amount = 5; City = Center; Land Farm;

LUST ID 46
LUST Standing Inactive
Date 12/17/1991
Status Site Cleanup Completed
Staff Lead David Swlick
Lead Party RP-Lead
AST or Exempt ☐

Status

Date	Status/Lead Party	Priority	Comments
12/18/1991	Site Cleanup Completed RP-Lead	50	Approximately 5 yards of contaminated sand fill removed.
12/17/1991	Tank Release Under Control RP-Lead	29	Contamination confined to sandfill..
12/17/1991	LUST Cleanup Initiated: Petroleum RP-Lead	27	Contaminated sand backfill removed.
12/17/1991	Confirmed Release RP-Lead	19	Petroleum contamination detected during ust removal.
12/17/1991	Routine Removal : Petroleum RP-Lead	18	280 gallon diesel ust removed.

Reporting Party

Party Type: State Official
Title: Env. Engineer
Name: David J Switlick
Company:
Address: 918 E Divide Avenue
City State Zip: Bismarck ND 58502 -
Phone:)

How was release first discovered?

Comments
Contamination discovered removal

Responsible Party

Release Information

Tank Number 0001 Alt Tank ID 1 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments
This record was added after conversion.

Tank Number 0002 Alt Tank ID E-7 Tank Status Currently In Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991
Company 0
Comments
This record was added after conversion.

Tank Number 0003 Alt Tank ID E-8 Tank Status Currently In Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991
Company 0
Comments
This record was added after conversion.

Tank Number 0004 Alt Tank ID R-2 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991
Company 0
Comments
This record was added after conversion.

Tank Number 0005 Alt Tank ID R-3 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991
Company 0
Comments
This record was added after conversion.

Tank Number 0006 Alt Tank ID R-4 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991
Company 0
Comments
This record was added after conversion.

Tank Number 0007 Alt Tank ID R-5 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments
This record was added after conversion.

Tank Number 0008 Alt Tank ID R-6 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments
This record was added after conversion.

Tank Number 0009 Alt Tank ID R-9 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments
STAINING OBSERVED NEAR THE FILL PIPE, POSSIBLE OVERFILLS.; ROUTINE UST REMOVAL.

Receptor Information

Date	Offsite Receptor	Contaminant	Impact	Mitigated Date	Comment
12/17/1991	Tank Basin	Diesel	Unlikely	12/18/1991	Sand backfill in basin.

From: Susan Richman <susan7richman@gmail.com>
Sent: Tuesday, September 26, 2023 9:15:25 PM (UTC-02:00) Mid-Atlantic - Old
To: askNEPA <asknepa@hq.doe.gov>
Subject: [EXTERNAL] Draft EA for North Dakota CarbonSAFE: Project Tundra (DOE/EA-2197)

To NEPA:

Please accept my comments, in opposition to:

the draft EA for *North Dakota CarbonSAFE: Project Tundra* (DOE/EA-2197), which assesses the potential environmental impacts of DOE providing cost-sharing financial assistance to Minnkota Power Cooperative, Inc. (Minnkota) for the project.

10-1 I have read, in ***Energy and Policy Institute*** dated Sept 14, 2023, https://energyandpolicy.org/department-of-energy-analysis-says-coal-carbon-capture-project-would-emit-more-greenhouse-gases-than-it-stores/

"There is an expected 3.23 kg of CO2e emitted per kg of CO2 stored."

Since carbon emissions are expected to exceed stored carbon, more than three times over, there is no reason for this project to go forward.

10-2 However, the article uncovered an even more disturbing fact:

"A Government Accountability Office report in 2021 documented problems with DOE's carbon capture program, including that 'DOE's process for selecting coal projects and negotiating funding agreements increased the risks that DOE would fund projects unlikely to succeed.' The GAO report specifically noted: 'According to DOE documentation and officials, senior leadership directed actions to support projects even though they were not meeting required key milestones.' "

It appears that the DOE is ensuring a project goes forward that does NOT meet their own requirements. That project will further spew

10-2 (cont'd.) carbon emissions into the atmosphere. Public safety and US climate goals are being sacrificed for a business opportunity. It is terrifying to think this is how our US government operates.

Please ensure a safe future on a livable planet, and a government body that abides by its own rules. A carbon capture project should create negative emissions. This project should not be funded. The DOE should be held to its own standards.

APPENDIX L – REVISED DRAFT ENVIRONMENTAL ASSESSMENT COMMENT RESPONSE DOCUMENT

U.S. Department of Energy

DOE/EA-2197

North Dakota CarbonSAFE: Project Tundra

Environmental Assessment

APPENDIX L
REVISED DRAFT ENVIRONMENTAL ASSESSMENT COMMENT RESPONSE DOCUMENT

INTENTIONALLY LEFT BLANK

Table of Contents

ACRONYMS AND ABBREVIATIONS

Acronym	**Definition**
BIL	Bipartisan Infrastructure Law
BSER	best system of emission reduction
CCS	carbon capture and storage
CCUS	Carbon Capture, Utilization, and Storage
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CO_2	carbon dioxide
DAC	disadvantaged community
DOE	U.S. Department of Energy
EA	Environmental Assessment
EGU Rule	New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule
EIS	Environmental Impact Statement
EJ	Environmental Justice
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FOA	Funding Opportunity Announcement
FONSI	Finding of No Significant Impact
GHG	greenhouse gas
IEN	Indigenous Environmental Network
IWG	Interagency Working Group
MRY	Milton R. Young Station
NEPA	National Environmental Policy Act
NGO	non-governmental organization
Project Tundra	North Dakota CarbonSAFE: Project Tundra
ROD	Record of Decision
SC-GHG	social cost of greenhouse gas
SIP	State Implementation Plan
Summit Pipeline	Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project
THPO	Tribal Historic Preservation Officer
WHEJAC	White House Environmental Justice Advisory Council's

APPENDIX L REVISED DRAFT ENVIRONMENTAL ASSESSMENT COMMENT RESPONSE DOCUMENT

L.1 1INTRODUCTION

The U.S. Department of Energy (DOE) prepared the Environmental Assessment (EA) for "North Dakota CarbonSAFE: Project Tundra" (Project Tundra) to evaluate the potential environmental, cultural, and socioeconomic impacts of partially funding a proposed project to design, construct, and operate an amine-based post-combustion carbon dioxide (CO_2) capture technology to treat flue gas from a separate but adjacent coal-fired power plant. This EA was released for public review and comment after publication of the Notice of Availability in the Bismarck Tribune on August 19, 2023. DOE received many comments on the Draft EA. Due to the increased level of public interest and number of comments received, DOE prepared a Comment Response document and reissued the Draft EA for public review and comment after publication of a second Notice of Availability in the Bismarck Tribune on April 13, 2024. An additional 30-day comment period, from April 13 to May 13, 2024, allowed interested parties to review the comments and responses, as well as any edits to the Draft EA.

DOE received five comment letters during the 30-day comment period for the Revised Draft EA, including one from the general public, one from a federal agency, and three from non-governmental organizations (NGOs). The five letters were sent from:

- Luis Vale Gomez, Carbono Capture at FIOR Processo
- U.S. Army Corps of Engineers
- Carbon Utilization Research Council
- Indigenous Environmental Network (IEN)
- Sierra Club, CURE, and Dakota Resource Council (joint)

This document summarizes the comments received and includes our responses to the comments. The appendix is organized into the following sections:

- Section L.2 provides DOE's responses to the comments received.
- Section L.3 provides copies of the comment letters received.

Upon receipt, all written comment documents were assigned a unique number for tracking during the comment response process. In processing the comment documents, each document was analyzed to identify individual comments and DOE prepared responses to the applicable comment themes.

In preparing this Final EA, DOE reviewed all comments received as part of the public comment period. The public comment period closed on May 13, 2024, but DOE considered late comments in preparation of the Final EA. Comments that DOE determined to be outside the scope of the Project Tundra EA are acknowledged as such in this appendix. Policy experts, subject matter experts, and National Environmental Policy Act (NEPA) specialists responded to the remaining substantive comments, as appropriate. This approach served to focus the revision process and ensure consistency throughout the final document. The comments were considered in determining whether the alternatives and analyses presented in the Revised Draft EA should be modified or augmented, whether information presented in the Revised Draft EA needed to be corrected or updated, and generally whether additional clarification was appropriate to facilitate clearer communication of information. Change bars in the margins of pages indicate where substantive changes were made and where text was added or deleted in the EA. Editorial changes are not marked.

Subsequent to the close of comments, DOE directed all Departmental Elements to include the U.S. Environmental Protection Agency's (EPA) 2023 social cost of greenhouse gas (SC-GHG) estimates in final documents to the extent that it is practical. DOE used the 2023 Interagency Working Group (IWG) SC-GHG estimates for the Revised Draft and has included both the IWG and EPA estimates in Section 3.17 of the Final EA.

L.2 RESPONSES TO COMMENTS RECEIVED

Comment Letter No. 1: Luis Vale Gomez, Carbono Capture at FIOR Processo

Comment 1-1, Carbon Capture Technology:

[The] "Benfield Solution " (CO3k2/CO3HK) IS MUCH BETTER, (Accordino my Experience) to CO_2 CAPTURE ,INSTEAD OF Amino Capture System . To Explain To you Better ,Contact me

Response to Comment 1-1:

Comment noted. DOE maintains a diverse portfolio of technologies and welcomes applications to our carbon capture funding opportunity announcements.

Comment Letter No. 2: U.S. Army Corps of Engineers

Comment 2-1, Clean Water Act Section 404 Permit:

U.S. Army Corps of Engineers Regulatory Offices administer Section 404 of the Clean Water Act (Section 404). A Section 404 permit would be required for the discharge of dredge or fill material (temporarily or permanently) in waters of the United States. Waters of the United States may include, but are not limited to, rivers, streams, ditches, coulees, lakes, ponds, and their adjacent wetlands. Fill material includes, but is not limited to, rock, sand, soil, clay, plastics, construction debris, wood chips, overburden from mines or other excavation activities and materials used to create any structure or infrastructure in waters of the United States.

Based on the information provided, the Corps has determined that your proposed project may need a Clean Water Act Section 404 permit if there is a discharge of dredge or fill material into any types of waters listed in the paragraph above. If the applicant decides to submit a permit application, the permit application and instructions for completing the application are enclosed and may also be found at: http://www.usace.army.mil/Missions/Civil-Works/Regulatory-Program-and- Permits/Obtain-a-Permit. Be sure to accurately describe all proposed work and construction methodology. Once the application is complete, mail it to the letterhead address or to the email address (preferred) below.

Response to Comment 2-1:

The Project is not expected to affect any Waters of the United States, and no Section 404 permit is required at this time. The Project will retain the permitting information in case of unexpected changes.

Comment Letter No. 3: Carbon Utilization Research Council

Comment 3-1, Project Support:

CURC [Carbon Utilization Research Council] agrees that Project Tundra's success will encourage the growth of a widespread industry for secure geologic CO_2 storage by reducing risks and costs for future projects and bringing more storage resources into commercial readiness… CURC commends DOE for its thorough analyses and extensive consultations with federal, state, and local agencies; Tribal governments; and non-governmental organizations in preparation of this EA. DOE is charged to advance the commercial readiness of CCUS [Carbon Capture, Utilization, and Storage] and the Bipartisan Infrastructure Law [BIL] appropriated funds under both the CarbonSAFE Initiative and the Carbon Capture Demonstration Projects Program to further the development, deployment, and commercialization of technologies to capture and geologically store CO_2 emissions securely in the subsurface. CURC will continue to work with DOE for successful implementation of projects to encourage the rapid growth of a vibrant, geographically widespread CCUS industry.

Response to Comment 3-1:

Comment noted.

Comment Letter No. 4: Indigenous Environmental Network (IEN)

Comment 4-1, No-Action Alternative:

IEN appreciates the DOE's efforts in responding and providing additional information to the comments submitted by stakeholders. At the same time, we must express our concern and frustration regarding DOE's approach to addressing stakeholder concerns, particularly in its dismissal of genuine risks raised in the submitted inputs. Instead of incorporating concerns to enhance the Draft EA's analysis, the comment response document (Annex K) simply justifies DOE's current decisions and statements, determining in a biased manner which factors and scenarios are deemed foreseeable and which are not. This approach fails to provide and ensure the transparency, accountability, and inclusivity necessary for the public to engage in meaningful decision-making, particularly when it comes to the purpose and alternatives of the project.

In light of this, IEN reiterates its original request to the DOE to abandon Project Tundra and move forward with a no-action alternative. However, should the DOE choose to persist with the project despite its devastating environmental, economic, social, cultural, and climate impacts, we implore the DOE to reassess the scope of the analysis and conduct a thorough Environmental Impact Assessment (EIA) that addresses all the pertinent concerns raised by rightsholders

Response to Comment 4-1:

As required by NEPA and its supporting regulations, DOE prepares an EA for a proposed DOE action that is described in the classes of actions listed in Title 10 of the Code of Federal Regulations (CFR) Part 1021, Subpart D, Appendix C and for a proposed DOE action that is not described in any of the classes of actions listed in Appendices A, B, or D to subpart D. An EA may result in a Finding of No Significant Impact (FONSI) or a determination to prepare an Environmental Impact Statement (EIS), if significant impacts are present that are not mitigated. At this time, DOE has found no significant impacts in the analysis of Project Tundra's environmental effects, and the preparation of an EIS is not warranted.

It is important to note that the conclusion of a NEPA document with a FONSI or a Record of Decision (ROD) does not constitute any decision on the part of DOE to proceed with the subject project. A NEPA document is intended to analyze the environmental impacts of the project and draw conclusions about the severity of those environmental impacts. Any CarbonSAFE Phase III projects analyzed under NEPA in this and related documents are required to apply for competitive consideration under Funding Opportunity Announcement (FOA) DE-FOA-0002711 to receive further funding under the CarbonSAFE program. Projects selected under the Office of Clean Energy Demonstrations (OCED) Carbon Capture Demonstration Projects Program FOA (DE-FOA-0002962) are in preliminary design phases with rigorous interim criteria and are subject to step-wise decisions to proceed into any future phases. DOE's decision to fund or not fund any project is subject to technical, financial, and environmental reviews.

Comment 4-2, Project Funding and Purpose and Need:

While Congress has appropriated funds for the CarbonSafe initiative for the development of commercial-scale [CCUS] projects and that the DOE does not have the authority to utilize these funds for any other purposes, it is important to recognize that this does not require the DOE to adopt such a narrow scope of purpose and need.

Response to Comment 4-2:

The purpose and need for DOE action is to advance the commercial readiness of carbon capture and storage (CCS) by supporting the construction of a commercial-scale geologic storage complex and associated CO_2 transport infrastructure. Successful implementation of Project Tundra would potentially contribute to the rapid growth of a geographically and geologically diverse industry for secure geologic carbon storage by reducing risks and costs for future projects and by advancing additional carbon storage resources into commercial classifications.

Please see the discussion of the CarbonSAFE Initiative's complete background and legislative history in Section 1.1 of the Revised Draft EA. In accordance with Congressional direction from both the Energy Policy Act and the Bipartisan Infrastructure Law (BIL), DOE does not have the authority to utilize these funds for any purpose other than commercial-scale CCS projects.

Through BIL, Congress appropriated funds under both the CarbonSAFE Initiative and the Carbon Capture Demonstration Projects Program to further the development, deployment, and commercialization of technologies to capture and geologically store CO_2 emissions securely in the subsurface. In alignment with Congressional direction, DOE issued DE-FOA-0002711 entitled "Storage Validation and Testing (Section 40305): Carbon Storage Assurance Facility Enterprise (CarbonSAFE)" and DE-FOA-0002962, "Carbon Capture Demonstration Projects Program."

Comment 4-3, Alternatives, Milton R. Young (MRY) Lifespan:

[This] does not absolve the DOE of its responsibility to conduct a thorough and holistic EA that communicates all relevant information needed for the public to understand and assess the risks and benefits of the proposed project. The need for a holistic view of the proposed project requires due consideration of the contextual factors of the project itself, which include but are not limited to the age and existing conditions of the MRY facility. This consideration is not "speculative" nor outside the scope of the study, but rather a crucial aspect of an EA's transparency and integrity which is central to the public's ability to have a complete picture of the potential environmental consequences, as well as understanding the possible range of better or more just alternatives.

Response to Comments 4-3:

See the responses to comments 4-5 and 5-1 below.

Comment 4-4, Alternatives:

IEN would like to highlight and reiterate the comment raised by the EPA in its submission, where they correctly pointed out that the analysis on the preferred alternative and the no-action alternative in the original and revised EA is discordant with the 2022 NEPA Implementing Regulations Revisions by the Council on Environmental Quality. The revisions noted that there may be times when an agency identifies a reasonable range of alternatives that include alternatives that are beyond the goals of the applicant or outside the agency's jurisdiction because the agency concludes that they are useful for the agency decision-maker and the public to make an informed decision.

Response to Comment 4-4:

The proposed action is for DOE to fund the project as designed and in the location proposed. The only no-action alternative is not funding the project. DOE either elects to fund the project and the technologies as designed by the applicant or the project does not get funded. The DOE FOA process is a competitive process and DOE is not permitted to make changes to the project application under Federal acquisition regulations. DOE can select a different project that fulfills the objectives of the FOA. Other projects that may apply for funding under DE-FOA-0002711 are the subjects of additional NEPA documents and will not be further analyzed here. Because DOE is directed to use appropriated funding by Congress to fund CCS projects, other technology alternatives are outside of the scope of the EA. Please see question 5-1 below for a further discussion of DOE's assumptions regarding the results of the no-action alternative.

Comment 4-5, MRY Lifespan and Cumulative Impacts:

This response also mentioned that projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. IEN implores the DOE to explore the aforementioned range of assumptions, as they are very much of interest to stakeholders, particularly Indigenous Peoples impacted by this project.

Additionally, a question remains unanswered: why is the assertion that the "storage reservoir developed under Project Tundra could be used to permanently sequester other anthropogenic CO_2, such as the geographically proximate proposed Summit Pipeline [Summit Carbon Solutions' Midwest Carbon Express CO2 Pipeline Project], in the future" considered an appropriate "reasonably foreseeable case" but not the inevitability of MRY being decommissioned if the proposed project is no longer pursued, especially with the wealth of research, expertise, and historical data supporting that claim? What are the DOE's criteria to determine a "reasonably foreseeable case"?

Response to Comment 4-5:

DOE does not speculate on the future of proposed regulations, the life-cycle decisions of a plant operator, or any other future decisions outside of its delegated statutory authority. The operational lifespan and future retirement of MRY Unit 1 and Unit 2 are based on many factors outside of DOE's purview and the scope of this EA. Projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. It is not reasonably foreseeable to identify a specific lifespan limit for MRY.

Cumulative impacts are defined as "the impact on the environment resulting from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions," including "actions by federal, non-federal and private parties." [40 CFR 1508.1 (i)(3)] DOE identifies cumulative impacts during scoping for NEPA documents, by contacting local officials and other parties to identify planned activities. Cumulative impacts are assessed to determine if the combined effect of the incremental activities creates a larger impact than the project alone. DOE complies with the NEPA regulations regarding reasonably foreseeable future work but does not assert that any of the possible future work will actually occur.

Comment 4-6, Tribal Consultation:

Consultation processes, as outlined by President Biden's memorandum on the uniform standards for Tribal consultation, must entail a two-way dialogue that respects Tribal sovereignty, acknowledges and respects Traditional Indigenous Knowledge, and seeks to meaningfully engage Tribal Nations in decision-making processes. While the DOE stated that it made outreach efforts to the federally recognized Tribal Nations in the project area, outreach alone does not constitute consultation and most certainly not consent. Sending out letters in no way guarantees that tribes actually receive the notices.

Tribal Nations may face various challenges to participating effectively in consultation processes including limited resources, time constraints, and historical distrust of federal agencies. IEN would like to urge the DOE to proactively anticipate and address these potential challenges by extending beyond outreach to ensure Indigenous Peoples' voices are accounted for. These actions might include but are not limited to, ensuring and documenting that the Tribal Nations received the documents sent, providing additional capacity and technical support, setting up in person meeting with Tribal Members, and offering longer deadlines to submit comments to allow for sufficient time to review and respond to the proposed project. When doing so, IEN urges the DOE to ensure that the consultation process is culturally sensitive, linguistically accessible, and respects the unique decision-making structures within Tribal Nations.

More importantly than this, consultation is not consent. No amount or type of consultation can substitute consent. The free prior informed consent of any and all Indigenous Peoples affected by a potential project is the bare minimum for a project like this to move forward, and in the absence of explicit consent, consent cannot and must not be assumed. We urge the DOE to recognize the rights of Indigenous Peoples and inherent jurisprudence to provide or withhold consent, as articulated in the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), and caution against moving forward without doing so.

Response to Comment 4-6:

As part of the NEPA process, DOE also complies with Section 106 of the Historic Preservation Act, which requires consultation with applicable Federally recognized Tribal Nations in certain circumstances. As part of this compliance, DOE mails letters to Tribal Nations using certified mail. Because our office uses an online application for mailing services, we no longer receive the paper delivery receipts for publication in the EA. Letters were mailed to the Tribal Nations on July 24, 2023 and April 9, 2024, and delivery was confirmed. One letter came back as "undeliverable" to the addresses supplied by the Tribal Directory Assessment Tool, and a copy of the letter was sent to an alternate address identified via an online search. Hardcopies of the Draft EA and Revised Draft EA were also mailed to the Tribal Leader and Tribal Historic Preservation Officer (THPO) of each of the Federally recognized Tribal Nations.

While agency consultations are subject to a 30-day time limit, there are no time limits on consultations with Tribal Nations. DOE respectfully requests 30 days so that the NEPA process can proceed and conclude within the statutory time limits, but DOE continues to receive and incorporate comments from Tribal Nations at any time after initiating consultation.

Consultation with the Federally recognized Tribal Nations was initiated by letter in July 2023 and continued in August 2023 with the hardcopy Draft EA, and with both a second consultation letter and the Revised Draft (mailed separately) in April 2024. DOE has contacted the Federally recognized Tribal Nations four times and has received no responses to date.

Comment 4-7, Environmental Justice (EJ):

There are significant areas where further improvement is crucial and necessary to ensure equitable outcomes for impacted communities, especially disadvantaged, marginalized, and EJ communities already burdened with the existing environmental hazards and pollution from the MRY facility.

The DOE's response highlighted the potential for clean energy job creation as a direct benefit to disadvantaged communities. However, it fails to outline any hiring policies or other mechanisms to ensure equitable access to these jobs, especially for higher wage positions such as those in architecture, engineering, and project management that were mentioned for this project. Without targeted interventions to address disparities in access to the education and training opportunities for these jobs, there is a risk that the benefits of job creation will not go to members of disadvantaged communities. This in turn would compound existing environmental inequalities created by the MRY facility and would undermine any attempts at ensuring environmental justice.

The response also emphasized "energy democracy" as a Justice principle that the project can deliver. However, CCS development contradicts other key policy principles outlined for the DOE's implementation of Justice40, such as "decrease[ing] environmental exposure and burdens for DACs [disadvantaged communities]" and "increase[ing] energy resiliency in DACs," in which the latter includes the diversification and adoption of renewable energy sources like wind and solar. Given these contradictions, in combination with White House Environmental Justice Advisory Council's (WHEJAC) explicit statement that CCS is an example of the type of project that will not benefit communities nor serve environmental justice purposes, Project Tundra cannot be considered to serve environmental justice aims. Beyond policy or legalistic measures of environmental justice, CCS technologies pose significant negative health risks in a very material and concrete way. Key health risks pertaining to Project Tundra include potential water contamination, asphyxiation from a CO_2 leak, and the exposure to nitrogen oxides (NO_x), sulfur dioxide (SO_2), and/or particulate matter.

IEN implores the DOE to further expand its analysis of EJ considerations beyond the narrow scope of access to energy. The DOE must recognize that EJ encompasses a broader spectrum of social, economic, cultural, and environmental considerations. This expansion might include but is not limited to, potential risks to public health, social cohesion, risks of accidents and leaks, and procedural justice in decision-making, particularly in Tribal Nations, Indigenous populations, communities of color, and low-income neighborhoods.

Response to Comment 4-7:

There are no disadvantaged, marginalized, or EJ communities in the vicinity of the MRY station. A public meeting was held in Center, North Dakota, the nearest community to MRY, to hear comments on the air permit for MRY from any affected persons or communities. The meeting resulted in one positive comment and no negative remarks or concerns from the affected community. Please refer to the robust discussion and analysis of EJ and the communities served by MRY located at page 3-55 of the Revised Draft EA and at page K-15 of Appendix K.

Concerns about education and training opportunities are best addressed within a Community Benefits Plan. The project's Community Benefits Plan is not in the scope of an EA.

Comment 4-8, General Opposition:

[1] In light of the continued disregard towards the risks posed to the rights of Indigenous Peoples, sovereignty, and jurisprudence displayed in the DOE's comment response document (Annex K), IEN reiterates our strong denouncement of Project Tundra and CCS more generally as a false solution to climate change. [2] The key dangers of Project Tundra lie in its significant public health risks, egregious environmental justice impacts, and stark disregard for Indigenous Peoples' sovereignty, rights, and jurisprudence in its consultation process. Project Tundra will open the floodgates for dubious and dangerous projects that continue to harm Indigenous Peoples as well as perpetuate the climate crisis. [3] If the DOE continues to consider this project, it must take into account the need for a full Environmental Impact Assessment as mandated by [NEPA] to fully account for the risks and potential impacts of the proposed project. IEN implores the DOE to reject this project.

Response to Comments 4-8:

(1) DOE asserts that there is not a single "solution" to climate change and maintains a diverse portfolio of projects which cumulatively have a goal of "support[ing] efforts to build a clean and equitable energy economy that achieves zero-carbon electricity by 2035 and puts 'the United States on a path to achieve net-zero emissions, economy-wide, by no later than 2050' to benefit all Americans" (DOE 2023a). The capture of anthropogenic CO_2 from power plants, industrial process, and ambient air and subsequent sequestration of captured CO_2 through permanent storage or beneficial reuse are important tools in continuing to reduce greenhouse gases (GHGs) in the atmosphere. (2) The EA identified no significant health risks or EJ impacts. DOE completed a robust campaign to contact all Federally recognized Tribal Nations with interests in the area of Project Tundra in accordance with Section 106 of the National Historic Preservation Act, and has received no comments to date. See the response to comment 4-6 for more detail on Tribal consultation. (3) See the response to comment 4-1 for more detail on the preparation of an EA versus an EIS, and clarification of the purpose of NEPA review in decision-making.

Comment Letter No. 5: Sierra Club, CURE, and Dakota Resource Council

Comment 5-1, Alternatives and GHG Rule:

I. The Project Tundra Revised Draft [EA] incorporates an erroneous "no-action" alternative - DOE persists in using as its "no action" alternative a plan of operation for the Milton Young plant that is illegal under EPA regulations. Without Project Tundra, Milton Young must retire in 2032 or reduce its emissions significantly beginning in 2030 and retire in 2039, but DOE assumed under a "no action" scenario Milton Young would continue to emit [GHGs] at current levels for the proposed lifespan of the Project Tundra facility.

Response to Comment 5-1:

The commenter is referencing 40 CFR Part 60, Subpart UUUUb. Pursuant to Clean Air Act section 111, 42 U.S.C. § 7411 ("CAA § 111"), the EPA published its "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("EGU Rule") in the Federal Register on May 9, 2024, four days prior to the close of the comment period for the Revised Draft EA. The rule was not in place during the preparation of the Draft EA or the Revised Draft EA.

The purpose of this new rule is to reduce GHG emissions from fossil fuel-fired electric generating units. To do so, EPA is requiring these sources to reduce their emissions so that they are either equal to the reductions achievable by the best system of emission reduction (BSER) identified by EPA and/or in compliance with a state's State Implementation Plan (SIP). SIP requirements will not be published for 24 to 36 months from the effective date of the final rule of July 8, 2024, and currently, North Dakota has not issued a SIP implementing the EGU Rule's emissions guidelines for MRY and other existing facilities.

First, the commenter is incorrectly stating that, due to promulgation of the EGU Rule, MRY would be required to reduce GHG emissions by complying with EPA-issued standards and "either have to commit to cessation of operations by 2032, or fire 40% methane gas by 2030." The new rule allows MRY to achieve the necessary emissions reductions by compliance with either the newly published EPA-issued standards or with North Dakota's SIP. Therefore, MRY has a variety of options available to it to comply with the newly issued rule beyond the options the commenter provided.

Second, the commenter is incorrect by contending that DOE's no-action alternative must evaluate a situation in which MRY potentially ceases operations due to the impact of the EGU Rule. For project proposals, the Council on Environmental Quality (CEQ) has stated, and Federal courts have held, that during an agency's no-action alternative analysis, the current level of activity is used as the benchmark and should be considered. No-action alternatives are not meant to be speculative in nature and are not to reflect hypothetical future situations, such as MRY's potential cessation of operations. The alternatives analysis is subject to a rule of reason and is bound by some notion of feasibility.

DOE does not speculate on the life-cycle decisions of a plant operator or any other future decisions outside of its delegated statutory authority. The operational life span and future retirement of MRY Unit 1 and Unit 2 are based on many factors outside and beyond the scope of the project. Projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, technology, market conditions, fuel cost, future demand, and regulatory requirements. It is not reasonably foreseeable to identify a specific lifespan limit for MRY in the alternatives for this EA regardless of the promulgation of the EGU Rule. Therefore, DOE is correct in conducting its no-action alternative analysis with MRY continuing to operate as it is now, and presuming a future cessation is not appropriate for purposes of NEPA.

Lastly, the commenter's case law is not analogous to the current situation. The cited cases involved agency action that was contradictory to the agency's mandate. Here, DOE's no action alternative does not directly contradict the agency's mandate and instead reflects existing conditions consistent with NEPA. It is consistent with DOE's objectives and mandate as defined by the FOA, which is for carbon capture projects.

<u>Comments 5-2 and 5-3, 45Q Tax Credits:</u>

II. The Project Tundra Revised Draft [EA] continues to rely on a carbon capture configuration that is economically infeasible and legally tenuous under the Clean Air Act - The project as designed will not meet the 75% minimum capture threshold to qualify for 45Q tax credits. The Project's proponents have designed what appears to be an attempted end-run around this requirement by claiming it will capture 95% of emissions from Unit 2 as its "unit of design."

II.1 The [Revised Draft EA] fails to assess if Project Tundra will meet the minimum eligibility requirements of the critical 45Q tax credits, where a failure to procure full credits would render it economically infeasible - The proponents, and the [Revised Draft EA], erroneously assume the operator will also earn 45Q credits for carbon captured from Unit 1 (of which the proposed project is only designed to capture 20% of carbon dioxide emissions). If the proponents are somehow successful in qualifying for tax credits for carbon *dioxide captured from Unit 1, [Revised Draft EA] has failed to assess how increased operation of Unit 1 to obtain the economic benefit of those credits will nullify or outweigh any environmental benefits of the capture that does take place.*

Response to Comments 5-2 and 5-3:

Congress creates tax credits like 45Q to encourage the deployment of new technologies. DOE does not have any jurisdiction over power plant operation or the 45Q tax credit program. The 45Q program is not an environmental impact and is therefore not part of DOE's NEPA analysis. However, DOE anticipates that some applicants to its FOAs may choose to take advantage of such programs if they are eligible.

Comment 5-4, GHG Rule/111(d):

II.2 The [Revised Draft EA] fails to assess if Project Tundra will meet the minimum requirements of the final Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, or 111(d).

Response to Comment 5-4:

See the response to comment 5-1 above.

Comment 5-5, Energy Source(s):

III.1 The [Revised Draft EA] assumes that the massive energy consumption at the proposed capture plant is associated with energy from Minnkota's generating system, rather than coal or gas at the Milton Young station, which is inconsistent with DOE's FEED study for the facility.

Response to Comment 5-5:

DOE correctly attributed the electrical power to run the CCS project. The CCS project, which includes the capture unit, storage facility, and associated interconnections, will receive flue gas and purchase steam directly from MRY. Because the CCS project is owned by a separate entity, the electricity required to operate the CCS project will be purchased from the grid, similar to any large customer such as a gas separation facility or server farm. MRY generates electricity and sends it to a substation where electricity generated from other sources (including renewable sources) is also received. The carbon footprint of that substation is calculated to include all sources of power with their relative input percentages.

Comment 5-6, Effect on Coal Plant Operations:

III.2 The [Revised Draft EA] assumes that the capture unit will not impact the operations or dispatch of the underlying coal unit, inconsistent with economics of the 45Q tax credit and EPA's assumptions.

Response to Comment 5-6:

The CCS unit is structured physically and commercially to have no impact on the operation or dispatch of the MRY. Because the dispatch of the power plant is forecasted based on its market position, and because the project sponsors have structured the CCS project to not impact power plant economics, including impacts due to available tax credits, then in both the "no build" and the "build" cases, the dispatch should be the same.

Comment 5-7, Summit Pipeline and Enhanced Oil Recovery:

IV. Summit Carbon Solutions Carbon Express pipeline network - The [Revised Draft EA's] response to commenters' initial comments optimistically states that this project, if connected to a pipeline network, would only accept carbon dioxide from the proposed Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project (Summit Pipeline). Without any information on how this could be designed to be a one-way pipeline, the response to initial comments merely states that using the captured MRY carbon dioxide would not meet the "objective" of this funding and therefore wouldn't be consistent with the funding. This argument is tautological and merely wishful thinking. Indeed, the [Revised Draft EA] in no way describes any assurance, build specifications, legal limitations, or other enforceable controls that would stop this project from sending captured carbon dioxide to serve enhanced oil recovery (EOR) once it is connected to the Summit Pipeline.

Response to Comment 5-7:

There is no EOR associated with this project now and no possibility to conduct EOR in the future. The target formations in the well location do not contain any hydrocarbons. The NEPA standard for cumulative effects is "reasonably foreseeable future impacts." It is reasonably foreseeable that geographically proximate anthropogenic CO_2 from other sources will also be permanently sequestered in the storage complex. There is no connection to the Summit Pipeline other than the fact that it would be geographically proximate if built.

Comment 5-8, Water Use:

V. Water Use - The [Revised Draft EA's] conclusion that surface water impacts will not be significant despite the massive water usage required by the proposed project rests on a meaningless comparison, i.e. between the project's water usage and the flow of the entire Missouri River. When compared to, e.g., total industrial usage in the state of North Dakota, however, it is clear that the impact of the Project's water usage will be significant.

Responses to Comment 5-8:

The method of analysis for water usage is appropriate. The commenter suggests that DOE should only include impacts of industrial users on the surface water resources, and not include municipal or other users. Comparing impacts among a subcategory of other users is inconsistent with NEPA. DOE analyzes the severity of a project's impact on a resource as a whole.

INTENTIONALLY LEFT BLANK

L.3 PUBLIC COMMENT LETTERS

From: Luis Vale Gomes <lvalegomes@gmail.com>
Sent: Friday, April 12, 2024 10:12 PM
To: Fayish, Pierina M. <Pierina.Fayish@NETL.DOE.GOV>
Subject: [EXTERNAL]

Dear Lady Pierina
1-1 I guest the "Benfield Solution " (CO3k2/CO3HK)
IS MUCH BETTER ,(Accordino my Experience)
To CO2 CAPTURE ,INSTEAD OF Amino Capture System .
To Explain To you Better ,Contact me
Luis Filipe Vale Gomes ,
(Carbono Capture at FIOR Processo)
Technical Superintent

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, OMAHA DISTRICT
NORTH DAKOTA REGULATORY OFFICE
3319 UNIVERSITY DRIVE
BISMARCK, NORTH DAKOTA 58504-7565

May 3, 2024

NWO-2023-01368-BIS

Department of Energy
National Energy Technology Laboratory
Attn: Ms. Pierina Fayish
626 Cachran Mill Rd
Pittsburgh, Pennsylvania 15236

Dear Ms Fayish:

This is in response to information received on April 12, 2024 regarding the Draft Environmental Assessment for the proposed Minnkota Power, North Dakota CarbonSAFE: Project Tundra (DOE/EA-D2197) at the existing Milton R. Young coal power plant facility. The project is located in Sections 4 and 5, Township 141 North, Range 83 West, Oliver County, North Dakota.

U. S. Army Corps of Engineers Regulatory Offices administer Section 404 of the
2-1 Clean Water Act (Section 404). A Section 404 permit would be required for the discharge of dredge or fill material (temporarily or permanently) in waters of the United States. Waters of the United States may include, but are not limited to, rivers, streams, ditches, coulees, lakes, ponds, and their adjacent wetlands. Fill material includes, but is not limited to, rock, sand, soil, clay, plastics, construction debris, wood chips, overburden from mines or other excavation activities and materials used to create any structure or infrastructure in waters of the United States.

Based on the information provided, the Corps has determined that your proposed project may need a Clean Water Act Section 404 permit if there is a discharge of dredge or fill material into any types of waters listed in the paragraph above. If the applicant decides to submit a permit application, the permit application and instructions for completing the application are enclosed and may also be found at: http://www.usace.army.mil/Missions/Civil-Works/Regulatory-Program-and-Permits/Obtain-a-Permit. Be sure to accurately describe all proposed work and construction methodology. Once the application is complete, mail it to the letterhead address or to the email address (preferred) below.

The North Dakota Regulatory office prefers that all submissions are sent electronically to the following email address: CENWO-OD-RND@usace.army.mil instead of a hard copy by mail. Please split large attachments (>25 MB) into multiple emails if needed.

Please refer to identification number NWO-2023-01368-BIS in any correspondence concerning this project. If you have any questions, please contact Jeremy Nygard at U.S. Army Corps of Engineers, North Dakota Regulatory Office, 3319 University Drive, Bismarck, North Dakota 58504-7565, by email at *Jeremy.S.Nygard@usace.army.mil*, or telephone at (701) 255-0015 X 2006. For more information regarding our program, please visit our website at *http://www.nwo.usace.army.mil/Missions/RegulatoryProgram/NorthDakota.aspx*.

Sincerely,

Benjamin D. Reile

For Benjamin N. Soiseth
Chief, North Dakota Section

Enclosure

CURC CARBON UTILIZATION RESEARCH COUNCIL
ADVANCING FOSSIL ENERGY SOLUTIONS

May 13, 2024

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236

Submitted via email

Re: CURC Comments on DOE/EA-2197D Revised Draft Environmental Assessment for North Dakota CarbonSAFE: Project Tundra April 2024

The Carbon Utilization Research Council (CURC) appreciates the opportunity to submit these comments on the Revised Draft Environmental Assessment for North Dakota CarbonSAFE: Project Tundra. CURC is a membership coalition focused on technology solutions for the responsible and sustainable use of our fossil energy resources, including carbon capture, utilization, and storage (CCUS). CURC has a broad membership reflective of the full and diverse CCUS ecosystem, including natural gas and coal power plant owners, equipment manufacturers, technology innovators, national associations that represent the power sector, labor unions, fossil fuel producers, non-governmental entities, and state, university, and technology research organizations that are all leading innovators in the development and deployment of CCUS technology.

The revised draft environmental assessment (EA) considers the potential impacts of the Federal government (specifically, the Department of Energy (DOE)) partially funding Minnkota Power Cooperative, Inc. (Minnkota) for the proposed North Dakota CarbonSAFE: Project Tundra. Project Tundra would include the infrastructure and equipment for the capture and geologic storage of carbon dioxide (CO_2) generated by the currently operating Milton R. Young Station (MRY) in Center, North Dakota, utilizing an amine-based post-combustion CO_2 capture technology.

3-1 CURC agrees that Project Tundra's success will encourage the growth of a widespread industry for secure geologic CO_2 storage by reducing risks and costs for future projects and bringing more storage resources into commercial readiness.

DOE's Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative is designed to research the safe, efficient, and effective characterization and permitting of commercial-scale CO_2 Capture Utilization and Storage (CCUS) projects. "North Dakota CarbonSAFE: Project Tundra" was selected under CarbonSAFE Phase III and must complete the National Environmental Policy Act (NEPA) process for a potential Phase IV project award.

NEPA and its implementing regulations require that DOE, as a federal agency, to:

- Assess the environmental impacts of its proposed action;

2000 Pennsylvania Avenue, NW • Suite 6000 • Washington, DC 20006 • www.curc.net

CURC CARBON UTILIZATION RESEARCH COUNCIL
ADVANCING FOSSIL ENERGY SOLUTIONS

3-1 (cont'd)

- Identify any adverse environmental effects that cannot be avoided, should the proposed action be implemented;
- Evaluate alternatives to the proposed action, including a no-action alternative; and
- Describe the cumulative impacts of the proposed action together with other past, present, and reasonably foreseeable future actions.

DOE's Proposed Action is to provide cost-shared financial assistance to the proposed Project Tundra CarbonSAFE Phase IV. Under the No-Action Alternative, DOE would not provide cost-shared funding to the proposed project. The project would be delayed if other funding sources were pursued or, alternatively, Project Tundra may not be constructed. Regarding alternatives to the Proposed Action, Congress instructed DOE on how to utilize this funding and DOE does not have the authority to utilize these funds for any purpose other than commercial-scale CO_2 capture and sequestration projects. DOE can only choose to fund or not fund any of the projects applying under a competitive FOA. DOE's consideration of reasonable alternatives to Project Tundra under NEPA is therefore limited to the No-Action Alternative.

CURC agrees with DOE's assumption that, for the purposes of a NEPA evaluation of the impacts of a No-Action-Alternative (i.e., not funding the project), that the recipient would not pursue the project.

As analyzed in this EA, the project would be sized for capture and saline formation geologic storage of an annualized average of 4.0 million metric tons per year (Mmt/yr) of CO_2, with a design specification of at least 95 percent CO_2 capture from the flue gas from MRY Unit 1 (250 MW) and Unit 2 (455 MW) with Unit 2 as the principal unit of design. The CO_2 would be compressed and transported through a new 0.5-mile-long CO_2 pipeline to an injection site for permanent deep geologic storage.

Included in the EA is a life cycle analysis (LCA) study, Project Tundra Initial Life Cycle Analysis (Burns & McDonnell 2023), that was prepared to quantify the potential life cycle greenhouse gas (GHG) emissions which would result from implementation of the Project Tundra. The LCA study was conducted in accordance with Chapter 2 Proposed Action and Alternatives Project Tundra DOE/EA-2197D Revised Draft EA 2-11.

The LCA considered the CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6) emissions from upstream, the proposed project, and downstream processes. Upstream emissions were split into three categories: fuel extraction, fuel transportation, and MRY direct emissions. The downstream analysis included emissions from the transportation of CO_2 via pipeline from the proposed CO_2 capture facility to the injection site of the permanent geologic storage site. The combined emissions from upstream and electricity transportation account for a large majority of emissions contributing to the CO_2 intensity and these two sources of emissions are already in operation and will occur regardless of whether Project Tundra is constructed.

CURC highlights that the LCA finds the No-Action alternative results in emissions of 1170 kg CO_2e/MWh and the Proposed Action results in 455 kg CO_2e/MWh. This is a significant reduction in greenhouse gas emissions. CURC endorses DOE's inclusion of the greenhouse gas intensity metric of kg CO_2e/MWh (in addition to kg CO_2e emitted/kg CO_2 sequestered).

2

CARBON UTILIZATION RESEARCH COUNCIL
ADVANCING FOSSIL ENERGY SOLUTIONS

3-1 (cont'd) CURC commends DOE for its thorough analyses and extensive consultations with federal, state, and local agencies; Tribal governments; and non-governmental organizations in preparation of this EA. DOE is charged to advance the commercial readiness of CCUS and the Bi-partisan Infrastructure Law appropriated funds under both the CarbonSAFE Initiative and the Carbon Capture Demonstration Projects Program to further the development, deployment, and commercialization of technologies to capture and geologically store CO_2 emissions securely in the subsurface. CURC will continue to work with DOE for successful implementation of projects to encourage the rapid growth of a vibrant, geographically widespread CCUS industry.

Respectfully submitted,

Shannon Angielski

Shannon Angielski, Executive Director
Carbon Utilization Research Council

3

Indigenous Environmental Network
PO Box 485
Bemidji, MN 56619

May 13, 2024

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236
412.386.5428

Re: Comments on the Revised Draft Environmental Assessment (EA) for the proposed North Dakota CarbonSAFE: Project Tundra (DOE/EA-D2197).

To: The Department of Energy and the Office of National Energy Technology Laboratory,

The Indigenous Environmental Network (IEN) submits this document in response to the call for comments on the Revised Draft Environmental Assessment (EA) for the proposed North Dakota Carbon SAFE: Project Tundra (DOE/EA-D2197). IEN is a non-profit 501(c)3 Indigenous-led organization based in Minnesota, United States with remote offices throughout North America, Turtle Island. IEN is an alliance of Indigenous Peoples whose mission it is to protect the sacredness of Mother Earth from contamination and exploitation by strengthening, maintaining, and respecting Indigenous teachings and natural laws.

4-1 IEN appreciates the DOE's efforts in responding and providing additional information to the comments submitted by stakeholders. At the same time, we must express our concern and frustration regarding DOE's approach to addressing stakeholder concerns, particularly in its dismissal of genuine risks raised in the submitted inputs. Instead of incorporating concerns to enhance the draft EA's analysis, the comment response document (Annex K) simply justifies DOE's current decisions and statements, determining in a biased manner which factors and scenarios are deemed foreseeable and which are not. This approach fails to provide and ensure the transparency, accountability, and inclusivity necessary for the public to engage in meaningful decision-making, particularly when it comes to the purpose and alternatives of the project.

In light of this, IEN reiterates its original request to the DOE to abandon Project Tundra and move forward with a no-action alternative. However, should the DOE choose to persist with the project despite its devastating environmental, economic, social, cultural, and climate impacts, we implore the DOE to reassess the scope of the analysis and conduct a thorough Environmental Impact Assessment (EIA) that addresses all the pertinent concerns raised by rightsholders.

<u>On No-Action Alternatives and Connected Actions:</u>

4-2 While Congress has appropriated funds for the CarbonSafe initiative for the development of commercial-scale CCS projects and that the DOE does not have the authority to utilize these funds for any other purposes, it is important to recognize that this does not require the DOE to adopt such a narrow scope of purpose and need. Moreover, this does not absolve the DOE of its responsibility to conduct a
4-3 thorough and holistic EA that communicates all relevant information needed for the public to understand and assess the risks and benefits of the proposed project. The need for a holistic view of the proposed project requires due consideration of the contextual factors of the project itself, which include but are not limited to the age and existing conditions of the MRY facility. This consideration is not "speculative" nor outside the scope of the study, but rather a crucial aspect of an EA's transparency and integrity which is central to the public's ability to have a complete picture of the potential environmental consequences, as well as understanding the possible range of better or more just alternatives.

4-4 IEN would like to highlight and reiterate the comment raised by the EPA in its submission, where they correctly pointed out that the analysis on the preferred alternative and the no-action alternative in the original and revised EA is discordant with the 2022 NEPA Implementing Regulations Revisions by the Council on Environmental Quality.[1] The revisions noted that there may be times when an agency identifies a reasonable range of alternatives that include alternatives that are beyond the goals of the applicant or outside the agency's jurisdiction because the agency concludes that they are useful for the agency decision-maker and the public to make an informed decision. This response also mentioned that
4-5 projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. IEN implores the DOE to explore the aforementioned range of assumptions, as they are very much of interest to stakeholders, particularly Indigenous Peoples impacted by this project.

Additionally, a question remains unanswered: why is the assertion that the "storage reservoir developed under Project Tundra could be used to permanently sequester other anthropogenic CO2, such as the geographically proximate proposed Summit Pipeline, in the future"[2] considered an appropriate "reasonably foreseeable case" but not the inevitability of MRY being decommissioned if the proposed project is no longer pursued, especially with the wealth of research, expertise, and historical data supporting that claim? What are the DOE's criteria to determine a "reasonably foreseeable case"?

<u>On Tribal Nation Consultation:</u>

4-6 Consultation processes, as outlined by President Biden's memorandum on the uniform standards for Tribal consultation, must entail a two-way dialogue that respects Tribal sovereignty, acknowledges and respects Traditional Indigenous Knowledge, and seeks to meaningfully engage Tribal Nations in decision-making processes.[3] While the DOE stated that it made outreach efforts to the federally recognized Tribal Nations in the project area, outreach alone does not constitute consultation and most certainly not consent. Sending out letters in no way guarantees that tribes actually receive the notices,

---

1 https://www.govinfo.gov/content/pkg/FR-2022-04-20/pdf/2022-08288.pdf
2 Comment Response Document, K-7.
3 https://www.whitehouse.gov/briefing-room/presidential-actions/2022/11/30/memorandum-on-uniform-standards-for-tribal-consultation/

4-6 (cont'd) have adequate time and capacity to review the materials and formulate meaningful responses, or that responses will be taken into account.

Tribal Nations may face various challenges to participating effectively in consultation processes including limited resources, time constraints, and historical distrust of federal agencies. IEN would like to urge the DOE to proactively anticipate and address these potential challenges by extending beyond outreach to ensure Indigenous Peoples' voices are accounted for. These actions might include but are not limited to, ensuring and documenting that the Tribal Nations received the documents sent, providing additional capacity and technical support, setting up in person meeting with Tribal Members, and offering longer deadlines to submit comments to allow for sufficient time to review and respond to the proposed project. When doing so, IEN urges the DOE to ensure that the consultation process is culturally sensitive, linguistically accessible, and respects the unique decision-making structures within Tribal Nations.

More importantly than this, consultation is not consent. No amount or type of consultation can substitute consent. The free prior informed consent of any and all Indigenous Peoples affected by a potential project is the bare minimum for a project like this to move forward, and in the absence of explicit consent, consent cannot and must not be assumed. We urge the DOE to recognize the rights of Indigenous Peoples and inherent jurisprudence to provide or withhold consent, as articulated in the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), and caution against moving forward without doing so.

On Environmental Justice (EJ):

4-7 There are significant areas where further improvement is crucial and necessary to ensure equitable outcomes for impacted communities, especially disadvantaged, marginalized, and EJ communities already burdened with the existing environmental hazards and pollution from the MRY facility.

The DOE's response highlighted the potential for clean energy job creation as a direct benefit to disadvantaged communities. However, it fails to outline any hiring policies or other mechanisms to ensure equitable access to these jobs, especially for higher wage positions such as those in architecture, engineering, and project management that were mentioned for this project. Without targeted interventions to address disparities in access to the education and training opportunities for these jobs, there is a risk that the benefits of job creation will not go to members of disadvantaged communities.[4] This in turn would compound existing environmental inequalities created by the MRY facility and would undermine any attempts at ensuring environmental justice.

The response also emphasized "energy democracy" as a Justice40 principle that the project can deliver. However, CCS development contradicts other key policy principles outlined for the DOE's implementation of Justice40, such as "decreas[ing] environmental exposure and burdens for DACs" and "increas[ing] energy resiliency in DACs," in which the latter includes the diversification and adoption of renewable energy sources like wind and solar.[5] Given these contradictions, in combination with White

[4] https://www.co2captureproject.org/xt457PuN/report/stakeholder_issues_report_March_2012.pdf
[5] https://www.energy.gov/justice/justice40-initiative

4-7 (cont'd) House Environmental Justice Advisory Council's (WHEJAC)[6] explicit statement that CCS is an example of the type of project that will not benefit communities nor serve environmental justice purposes, Project Tundra cannot be considered to serve environmental justice aims. Beyond policy or legalistic measures of environmental justice, CCS technologies pose significant negative health risks in a very material and concrete way. Key health risks pertaining to Project Tundra include potential water contamination, asphyxiation from a CO2 leak, and the exposure to nitrogen oxides (NOx), sulfur dioxide (SO2), and/or particulate matter.[7][8]

IEN implores the DOE to further expand its analysis of EJ considerations beyond the narrow scope of access to energy. The DOE must recognize that EJ encompasses a broader spectrum of social, economic, cultural, and environmental considerations. This expansion might include but is not limited to, potential risks to public health, social cohesion, risks of accidents and leaks, and procedural justice in decision-making, particularly in Tribal Nations, Indigenous populations, communities of color, and low-income neighborhoods.

<u>Conclusion:</u>

4-8 In light of the continued disregard towards the risks posed to the rights of Indigenous Peoples, sovereignty, and jurisprudence displayed in the DOE's comment response document (Annex K), IEN reiterates our strong denouncement of Project Tundra and CCS more generally as a false solution to climate change. The key dangers of Project Tundra lie in its significant public health risks, egregious environmental justice impacts, and stark disregard for Indigenous Peoples' sovereignty, rights, and jurisprudence in its consultation process. Project Tundra will open the floodgates for dubious and dangerous projects that continue to harm Indigenous Peoples as well as perpetuate the climate crisis. If the DOE continues to consider this project, it must take into account the need for a full Environmental Impact Assessment as mandated by the National Environmental Policy Act (NEPA) to fully account for the risks and potential impacts of the proposed project. IEN implores the DOE to reject this project

Sincerely,

Tom Goldtooth

Tom BK Goldtooth
Executive Director
Indigenous Environmental Network
PO Box 485
Bemidji, MN 56619
(218) 751-4967

[6] https://legacy-assets.eenews.net/open_files/assets/2021/05/17/document_ew_01.pdf
[7] https://shalegas-bg.eu/download/ccs/100106-Health-Risks-CCS.pdf
[8] https://www.oaklandinstitute.org/sites/oaklandinstitute.org/files/pdfpreview/carbon_capture_health_risks_1_page.pdf

May 13, 2024

VIA EMAIL

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236
Pierina.Fayish@netl.doe.gov

RE: Comments on the Revised Draft Environmental Assessment for Project Tundra on Behalf of Sierra Club, CURE, and Dakota Resource Council

Dear Ms. Fayish:

Sierra Club, CURE, and Dakota Resource Council submit these comments on the Revised Draft Environmental Assessment (RDEA) for DOE/EA-2197: North Dakota CarbonSAFE: Project Tundra, dated April 2024.

Sierra Club and CURE previously identified numerous concerns with both Project Tundra itself and the Department of Energy ("DOE")'s inadequate analysis of its environmental consequences in their Comments on the Draft Environmental Assessment of September 19, 2023. Sierra Club, CURE, and Dakota Resource Council incorporate those previous comments by reference.

Unfortunately, despite the DOE's revisions, the RDEA for what "would be the world's largest post-combustion CO2 capture and geologic storage project"[1] still falls short of legal standards under the National Environmental Policy Act ("NEPA") and its implementing regulations. DOE's conclusion that funding Project Tundra will have no significant adverse environmental impacts is unfounded and incorrect.

First, DOE persists in using as its "no action" alternative a plan of operation for the Milton Young plant that is *illegal* under EPA regulations. Without Project Tundra, Milton Young must retire in 2032 or reduce its emissions significantly beginning in 2030 and retire in 2039, but DOE assumed under a "no action" scenario Milton Young would continue to emit greenhouse gasses at current levels for the proposed lifespan of the Project Tundra facility.

Second, the project as designed will not meet the 75% minimum capture threshold to qualify for 45Q tax credits. The Project's proponents have designed what appears to be an attempted end-run around this requirement by claiming it will capture 95% of emissions from Unit 2 as its "unit of design." But the proponents, and the RDEA, erroneously assume the operator will *also* earn 45Q credits for carbon captured from Unit 1 (of which the proposed project is only designed to capture

[1] U.S. DOE, DOE/EA-2197D Project Tundra Revised Draft Environmental Assessment for North Dakota, CarbonSAFE: Project Tundra, (Apr. 13, 2024), *available at* https://www.energy.gov/nepa/articles/doeea-2197-revised-draft-environmental-assessment-april-2024 (hereinafter "RDEA"), at § 2.5, 2-2.

1

20% of carbon dioxide emissions). If the proponents are somehow successful in qualifying for tax credits for carbon dioxide captured from Unit 1, RDEA has failed to assess how increased operation of Unit 1 to obtain the economic benefit of those credits will nullify or outweigh any environmental benefits of the capture that does take place.

Third, in calculating the lifecycle carbon emissions associated with the Project, the RDEA improperly assumes the large quantity of electricity used to operate the capture technology will come from the MISO market, rather than Milton Young itself, significantly undercounting the greenhouse gas and other air pollution emissions associated with the Project's electricity usage.

Fourth, the RDEA ignores the adverse environmental impacts associated with the use of captured carbon dioxide for enhanced oil recovery ("EOR"), even though there are no legal or physical limits on the use of carbon dioxide captured from Milton Young for EOR once the gas is inserted into the Summit Carbon Solutions Carbon Express pipeline, and evidence that linking the capture project at Milton Young to the Summit pipeline will directly or indirectly promote the use of carbon dioxide in EOR.

Fifth, the RDEA's conclusion that surface water impacts will not be significant despite the massive water usage required by the proposed project rests on a meaningless comparison, *i.e.* between the project's water usage and *the flow of the entire Missouri River*. When compared to, *e.g.*, total industrial usage in the state of North Dakota, however, it is clear that the impact of the Project's water usage will be significant.

The DOE's putative finding of no significant impact is premised on a faulty and legally inadequate environmental assessment and must be reversed. Sierra Club, CURE, and Dakota Resource Council urge the DOE to address these errors, find the impact of the Project will be significant, and complete a full Environmental Impact Statement process, as NEPA requires.

5-1

I. The Project Tundra Revised Draft Environmental Assessment incorporates an erroneous "no-action" alternative

The RDEA assumes that without project funding, *i.e.* in the "no-action alternative," Project Tundra would not be constructed.[2] The RDEA then compares rate of carbon dioxide emissions per MWh produced in the "no-action" and Project Tundra alternatives, and concludes that under the no-action alternative, the life-cycle carbon emissions associated with a single MWh of electricity would be equal to 1,170kg, as compared to 455kg if Project Tundra were constructed and operated as described.[3] This comparison assumes that the plant will operate in the same manner it currently does for the lifespan of the proposed project (20 years). Similarly, for purposes of calculating the social cost of carbon emissions as part of its cumulative impacts analysis in the no-build and build scenarios, the RDEA assumes Milton Young will continue burning coal through 2048.[4]

[2] RDA at § 2.3, 2-1.
[3] RDEA at Table 3-10, 3-14.
[4] *Id.* at § 3.17, 3-58-3-59.

2

5-1 (cont'd)

This "no action" alternative is unlawful and unreasonable. NEPA requires that agencies consider "a reasonable range of alternatives to the proposed agency action, including . . . a no action alternative, that are technically and economically feasible."[5] In conducting such an analysis, the agency's evaluation of alternatives "must be bounded by some notion of feasibility.[6]

Under current federal emission standards, 40 C.F.R. Part 60, Subpart UUUUb, if not retrofitted with carbon capture, Milton Young will either have to (a) commit to cease operations by 2039 and co-fire with 40% natural gas by January 1, 2030; *or* (b) cease operation by January 1, 2032. The RDEA ignores these federal requirements entirely, and assumes, under the no-action alternative, Milton Young will continue to emit carbon dioxide (as well as produce greenhouse gas emissions from upstream procurement of coal and other fuels) at the same rate as it currently does for the 20-year lifespan of Project Tundra. But under a "no action" alternative in which Project Tundra is *not* constructed, Milton Young will either be required to significantly reduce its greenhouse gas emissions from 2030-2039, followed by retirement (and thus no emissions) for nine years within the 20 years of Project Tundra analysis *or* will cease emitting greenhouse gasses altogether by 2032. The RDEA assumes a baseline for "no action" that will only be relevant for the first four years of Project Tundra's lifespan (at most), after which the build scenario will entail *greater* greenhouse gas emissions than the retirement scenario.

In other words, instead of evaluating a true "no action" alternative where Milton Young is required to comply with now-final greenhouse gas emission limitations, DOE compares its preferred alternative of retrofitting the facility with CCS to an illegal "no action" alternative in which Milton Young operates without pollution controls until 2048. But that purported "no action" alternative is, "in fact no alternative at all" because "actions that would violate [applicable law] cannot be reasonable alternatives to consider."[7]

This error renders the RDEA's Finding of No Significant Impact invalid. To determine whether the construction of Project Tundra will have a significant adverse environmental impact as a result of increased greenhouse gas emissions, the Department of Energy must re-do its life-cycle carbon emissions and social cost of greenhouse gas analyses with two "no-action" alternatives: one in which Milton Young is retired in 2032, and another in which it co-fires natural gas as required under 40 C.F.R. Part 60, Subpart UUUUb from January 1, 2030 through 2039, followed by retirement. Sierra Club's calculations suggest that such an analysis shows a significant adverse impact due to the construction of Project Tundra, as continuing to operate the plant with partial greenhouse gas capture will result in 8.7 million tons of additional greenhouse gas emissions from the plant itself (*i.e.* not including upstream or lifecycle emissions) relative to a "no-action" alternative in which Project Tundra is not built and Milton Young ceases operation by January 1, 2032, in compliance with federal Clean Air Act standards.

[5] 42 U.S.C. § 4332(C)(iii).

[6] *Vermont Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc.*, 435 U.S. 519, 551 (1978).

[7] *Flaherty v. Bryson*, 850 F. Supp. 2d 38, 72–73 (D.D.C. 2012); *see also Am. Oceans Campaign v. Daley*, 183 F. Supp. 2d 1, 20 (D.D.C. 2000) (holding that the agency failed to consider reasonable alternatives where EAs did "not even consider any alternatives besides the status quo (which would violate the [law]).").

3

5-1 (cont'd) Moreover, as discussed in greater detail below, it is not at all clear that Project Tundra, as designed, will enable Milton Young to comply with 40 C.F.R. Part 60 as a "long term" unit. That is, the Project's design is at odds with federal emission rules for coal-fired electrical generating units, a fact the RDEA also fails to address.

5-2

II. The Project Tundra Revised Draft Environmental Assessment continues to rely on a carbon capture configuration that is economically infeasible and legally tenuous under the Clean Air Act

The RDEA suffers from at least two major additional flaws stemming from the Project's multi-unit design: First, the RDEA fails to acknowledge the likely conflict between the project's design, as proposed to be funded, and federal policy. Second, it fails to properly analyze and document economic considerations associated with the project and closely interrelated with its emission impacts because it assumes–incorrectly–that the project will be economically viable on the basis of claimed tax credits for which it is not eligible. This mistake leads the RDEA to drastically understate the economic impacts of the project for Minnkota ratepayers and potentially overstate the amount of carbon capture and thus the purported net economic benefits of the project's operation.

Specifically, the proposed action would fund a project that is constructed to capture only a small fraction of the carbon oxide emissions from Milton Young Unit 1, but which (according to the Project's proponents) would nevertheless claim 45Q revenue for these emissions, in conflict with federal tax policy regarding 45Q credits. This basic error gives rise to at least two conflicts between the proposed action (funding of Project Tundra, as designed) and other federal policies, neither of which are discussed in the RDEA: first, the RDEA assumes that in order to be economically feasible, Project Tundra's operator must be eligible for and receive revenue from the 45Q tax credit for carbon oxide sequestration.[8] Second, the proposed configuration in the RDEA will not meet EPA's finalized New Source Performance Standards for greenhouse gasses, meaning the construction of Project Tundra as designed will lead to the forced retirement of Unit 1 in 2032, but this fact is nowhere discussed in the RDEA. DOE should not fund Project Tundra on the basis of an EA that fails to grapple with the implications of the project's design for both tax and Clean Air Act policy, or which mistakenly assumes the project design is compatible with these other federal requirements..

5-3

1. The RDEA fails to assess if Project Tundra will meet the minimum eligibility requirements of the critical 45Q tax credits, where a failure to procure full credits would render it economically infeasible

As noted in our comments on the Draft EA, it is imperative that DOE assess whether Project Tundra is consistent with federal tax policy under section 45Q. A NEPA evaluation is only meaningful if the recipient could actually pursue the project. Without the assurance of the 45Q

[8] Minnkota Power Cooperative, "Project Tundra Frequently Asked Questions," (2023), *available at* https://www.projecttundrand.com/faq ("The vast majority of capital and operating costs will be funded through the federal 45Q tax credit, which works similarly to the kinds of tax credits that wind and solar projects have utilized for decades. The tax credit provides $85 per ton of CO_2 that is permanently stored underground over a 12-year period").

4

5-3 (cont'd) tax credit, the recipients could not finance, and would not pursue Project Tundra. Conversely, if the project proponents proceed to construct and operate a CCS project (potentially at significant expense to ratepayers) notwithstanding this ineligibility, DOE must knowingly decide to commit taxpayer funds to such an endeavor. And the "no action" alternative (which assumes without funding the project will not proceed) is only meaningful *if* the proposed action makes Project Tundra economically feasible.

According to the proponents, "[t]he $1.45 billion project will primarily be funded through federal 45Q tax credits,"[9] and this assumption remains true in the RDEA. To be eligible for the tax credit under 26 U.S.C. § 45Q(d)(2)(B)(ii), a "qualified facility" (*i.e.* a carbon capture project) at an electricity generating facility must capture at least 18,750 metric tons of CO_2 per year and be designed to capture at least 75 percent of historic (or "baseline") emissions at the unit for which it was designed.[10] Project Tundra fails to meet this minimum criteria.

Project Tundra is sized to capture more emissions than Unit 2 alone, but fewer emissions than would be required if it were sized for both Units 1 and 2. The RDEA states, in response to comments:

> The design of this CCS system to simultaneously accept and process flue gas from Unit 1 and Unit 2 permits the system to capture much more CO_2 than capture systems that are paired with a single generating unit. The CCS is designed and sized to process 100% flue gas from Unit 2 (the larger of the two units at the site) **plus an estimated 20% of the flue gas from Unit 1**…[11]

Despite this acknowledgement, elsewhere the RDEA claims that Project Tundra would have a "design specification of at least 95 percent CO_2 capture from the processed MRY [Milton Young] Unit 1 (250 megawatts gross [MWg] owned by Minnkota) and Unit 2 (455 MWg owned by Square Butte Electric) flue gas, [where] Unit 2 is the principal unit of design."[12]

This is factually incorrect. Project Tundra has a design specification of just 61.4 percent CO_2 capture from MRY Unit 1 and 2. According to the RDEA, "the project would be designed to capture up to 13,000 short tons per day (STPD) of CO_2,"[13] while the maximum daily emissions of Milton Young 1 and 2 are 21,150 short tons per day.[14]

---

[9] Minnkota Power Cooperative, "Project Tundra receives $100 million loan from state of North Dakota," (May 23, 2022), *available at* https://www.projecttundrand.com/post/project-tundra-receives-100-million-loan-from-state-of-north-dakota.

[10] 26 U.S.C. § 45Q(d)(2)(B)(ii) ("with respect to any carbon capture equipment for the applicable electric generating unit at such facility," the unit must have "a capture design capacity of not less than 75 percent of the baseline carbon oxide production of such unit").

[11] RDEA at Appendix K, K-10 (emphasis added).

[12] *Id.* at § 2.5, 2-2.

[13] *Id.* at § 2.5, 2-3.

[14] *Id.* at Appendix E, E-17, Table 1-2 ("No-Build Scenario" showing emissions from "Coal Electricity Plant" at 1,134 kg CO_2/MWh, or 1.25 short tons CO_2/MWh. At a total capacity of 705 MW, Milton Young has the potential to generate 16,920 MWh, or 21,150 short tons CO_2/day).

5

5-3 (cont'd)

Despite the eligibility of the tax credit only to Unit 2, the RDEA assumes that the entire project will be applicable to both stacks of the Milton Young plant for purposes of 45Q credit eligibility.[15] This assessment is in error.

Section 45Q(d)(2)(B)(ii) requires that a carbon capture facility demonstrate that the carbon capture equipment for the applicable generating unit has a capture design capacity of not less than 75 percent of the baseline carbon oxide production of the unit. The purpose of the statutory guardrail requiring "not less than 75 percent of baseline carbon oxide production" is to ensure that tax credits are only distributed to projects that actually have an emissions reduction value. The electricity and steam consumption of carbon capture projects are substantial; in this case, up to 27 percent of Milton Young's energy production, and more than 40 percent of Unit 2's energy production.[16] Unless a very high percentage of carbon oxide emissions from a unit are captured and sequestered, the increase in emissions associated with the additional electrical generation to power the carbon capture mechanism will outweigh the reduction in emissions due to capture from the flue stream. The 75 percent requirement is thus a guardrail designed to ensure that projects do not propose partial capture and subsidize the generation of high emissions power while providing little or no emissions benefit. The statute does not contemplate that a CCS project be constructed to process flue gas streams from multiple units but "apply" only to emissions from a single unit, because *powering* the CCS project to the degree necessary to apply to multiple units without *capturing* the emissions from both units would result in increased net emissions.

The 45Q statute lays out that the baseline for an existing generating unit is calculated as the average of the three highest emissions years in the last twelve years. The statute does not establish if for carbon capture units that apply to multiple units if the emissions from the multiple units are to be aggregated and then averaged, or averaged independently, and then aggregated. If the project goes online in 2028, using just 2016-2023 emissions, the baseline for an aggregated Milton Young is 6.1 million short tons, and the baseline for a disaggregated plant is 6.3 million tons. The 75 percent threshold for these baselines are 4.5 million short tons and 4.8 million short tons, respectively.

[15] *See id.* at § 3.2.2, 3-4, Table 3-3 (which shows several different possible configurations of Project Tundra, including "all" of Unit 2 and partial capture at Unit 1, all of Unit 1 and partial capture at Unit 2, Unit 1 alone, or Unit 2 alone). *See also id.* at § 3.2.2, 3-4 ("The project would have the consequential benefit of reducing further the emissions of CO_2, SO_2, and particulate matter from the existing MRY Unit 1 and Unit 2 flue gas streams"). *See also*, *id.* at Appendix K, K-10 ("The CCS is designed and sized to process 100% flue gas from Unit 2 (the larger of the two units at the site) plus an estimated 20% of the flue gas from Unit 1 when both generating units are operating at their <u>full capacities</u> including flexible operational mode variations" (emphasis original)).

[16] *See id.* at § 3.3.2, 3-9 ("Energy Consumption at the proposed capture plant has been incorporated as a plant direct emission. The capture plant will require both electricity and steam to operate. Engineering estimates for the capture plant estimate an approximate requirement of 1,848 megawatts [hours] [*sic*] per day of electricity and 2,640 megawatts [hours] [*sic*] electric (MWe) per day of thermal (steam) energy," for a total of 4,488 MWh of gross energy production (electricity and steam, combined). At full output, Milton Young plant would be expected to produce 16,920 MWh before auxiliary loads, and Unit 2 (the "principle unit of design") would produce 10,920 MWh. 4,488 MWh is 27 percent of the total output, and 41 percent of Unit 2's output).

6

5-3 (cont'd) The RDEA proposes that Project Tundra will capture "an annual average of 4.0 million [metric] tons of CO_2"[17] or 4.4 million short tons, and the life cycle assessment suggests that the unit could capture a maximum of 4.7 million short tons per year,[18] or the maximum capture of the project if it operated *every day of the year*. Assuming the entire plant is considered the applicable unit, Project Tundra's capture would have to exceed 75 percent of the baseline. Taken as a whole, Project Tundra is not scoped to capture the minimum 75 percent of baseline emissions as required under 45Q, except in the narrowest of readings.

As noted in our initial comments, the RDEA assumes that Project Tundra's 45Q eligibility will not be calculated on the basis of emissions from the stacks of both Milton Young Units 1 and 2. Pending guidance from the IRS, this interpretation could be critically incorrect, rendering this RDEA moot. To be eligible for a 45Q tax credit, Project Tundra must be sized to capture the minimum emissions from both Units 1 and 2, or applied to just Unit 2 alone. Project Tundra is either ineligible for the tax credit, or oversized relative to its applicable generating unit. If the project is ineligible for the 45Q tax credit, it will either fail to secure financing and not be built, or fail to recoup its capital and operating costs, and be shuttered (potentially at significant cost to rural member-owners with limited ability to shoulder this huge loss). If the project is built as scoped and is only eligible for emissions captured from Unit 2, the proponents will have spent substantially more capital to build an oversized unit, and fail to secure the full extent of the tax credits that appear to underlay the financing proposal.[19] Under both circumstances, Project Tundra would fail to achieve financial viability, rendering the proposed action infeasible, and the RDEA moot. DOE must account for the potential that federal guidance renders the project as proposed ineligible for 45Q. And in any case, the RDEA's failure to address this conflict with federal law renders its RDEA inadequate under NEPA.

5-4

2. The RDEA fails to assess if Project Tundra will meet the minimum requirements of the final Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, or 111(d).

On April 25, 2024, EPA finalized Emission Guidelines for Greenhouse Gases from Existing Electric Generating Units under Section 111(d) of the Clean Air Act. The rule establishes different requirements for subcategories of fossil-fired EGU. Under the final rule, existing coal-fired EGU that intend to operate on or after January 1, 2039 must have an emissions rate comparable to the application of carbon capture with 90% capture, and that rate must be met by January 1, 2032.

---

[17] *Id.* at § 3.3.2, 3-6.

[18] *Id.* at Appendix E, E-25 (Assumptions and Data).

[19] At the proposed capture rate of 4 million metric tons per year, the (uninflated) 45Q tax credit would theoretically yield $4.08 billion over the 12 year application period, or up to $4.39 billion if Project Tundra operated at its maximum utilization every day for 12 years (13,000 short tons per day). However, according to the Project Tundra FEED study, DOE estimates that the levelized cost of capture (including capital and operating costs) is $78.46/metric ton, which implies an all-in estimated cost of $4.05 billion for Project Tundra. However, if Project Tundra is only able to recoup 45Q for the operations of Unit 2, even assuming 90% capture and a 90% capacity factor for Milton Young Unit 2, it would only yield $3.73 billion. It is unreasonable to assume that the project could be successful with this lower than required yield.

7

5-4 (cont'd) Project Tundra's proposed carbon capture facility is, on paper, theoretically capable of 90% capture–but only for the stack of either Milton Young Unit 1 *or* Unit 2, not both.[20] The RDEA itself assesses that Project Tundra would capture just 77% of 2021 / 2022 emissions.[21] According to both the technical specifications in the FEED Study as well as the RDEA, Project Tundra would not be compatible with the final GHG emissions requirements. With an expected online date of 2028 or 2029, the project would only be 3 years old at the time the more stringent requirements come into effect in 2032.

For compliance with this rule (not 45Q), the RDEA could assess a scenario where the project is built as specified, but reverts to capture only at Milton Young Unit 2 on January 1, 2032. However, the RDEA would then also have to make an explicit assumption about the fate of the other unit (Milton Young Unit 1, in this case), because under the final rule, such units would either have to commit to cessation of operations by 2032, or fire 40% methane gas by 2030, as discussed above. Both of these options have significant ramifications for emissions and/or leakage, new construction, and the economics of Project Tundra.

Under the condition that Project Tundra is only applied to Unit 2 (as required under the final rule and 45Q), it would be substantially oversized,[22] and potentially fail to recover sufficient 45Q tax credits to make the project viable.

The RDEA states that "DOE does not speculate on the future of proposed 111(b) and 111(d) regulations, the life-cycle decisions of a plant operator, or any other future decisions outside of its delegated statutory authority."[23] Speculation is no longer necessary. 111(d) is no longer a proposed regulation, but final, and in force. The RDEA must account for it and assess a legally viable Proposed Action.

III. The Project Tundra Revised Draft Environmental Assessment still contains substantial errors, impacting emissions assumptions

The initial EA for Project Tundra contained substantial errors in estimating the lifecycle emissions of the proposed action,[24] as discussed below.

[20] *See* RDEA at § 3.3.2, 3-6 ("Note that a 95 percent unit-wide capture indicates that a 95 percent capture efficiency is occurring at U1 *or* U2 at MRY" (emphasis added)).

[21] *See id.* ("Between 2021 and 2022, the MRY plant emitted flue gas with an average of 5,187,363 tons of CO_2. Electricity generation at MRY and the associated emissions processes are already in operation and would occur with or without construction and operation of the project. The proposed project would not capture and treat 100 percent of the CO_2 produced by the MRY coal plant, however, over the lifetime of the carbon capture facility it is projected to capture an annual average of 4.0 million tons of CO_2").

[22] *Id.* at Appendix K, K-10 ("The design of this CCS system to simultaneously accept and process flue gas from Unit 1 and Unit 2 permits the system to capture *much more CO_2 than capture systems that are paired with a single generating unit.* The CCS is designed and sized to process 100% flue gas from Unit 2 (the larger of the two units at the site) plus an estimated 20% of the flue gas from Unit 1 when both generating units are operating at their full capacities including flexible operational mode variations" (italics added, emphasis original)).

[23] *Id.* at Appendix K, K-9.

[24] RDEA Table 3-7: Proposed Action, Initial Life Cycle Analysis Results (kg of emissions / MWh)

8

5-5

1. The RDEA assumes that the massive energy consumption at the proposed capture plant is associated with energy from Minnkota's generating system, rather than coal or gas at the Milton Young station, which is inconsistent with DOE's FEED study for the facility

Unlike the previous Draft EA, the RDEA now assesses the impact of energy consumption occurring at the carbon capture facility. However, the RDEA miscalculates the substantial emissions associated with energy consumption from the carbon capture equipment by allocating that energy to "purchased electricity" rather than the plant itself or a supplemental boiler, which would be the source of electricity to operate the equipment according to the proposed configurations of Project Tundra.

The RDEA acknowledges that the capture plant will require both substantial electricity and steam to operate, stating

> Energy Consumption at the proposed capture plant has been incorporated as a plant direct emission. The capture plant will require both electricity and steam to operate. Engineering estimates for the capture plant estimate an approximate requirement of 1,848 megawatts per day of electricity and 2,640 megawatts electric (MWe) per day of thermal (steam) energy. The project would be expected to source electricity and thermal energy from the Minnkota generating system. Emissions from energy consumption were calculated following methodology adapted from EPA's Greenhouse Gas Inventory Guidance: Indirect Emissions from Purchased Electricity (EPA 2023b).[25]

The resulting 4,488 MWh electric equivalent[26] per day is roughly one third of the forecast generation of Milton Young–a huge portion of the energy (and emissions) of the power plant. This is not a marginal calculation, but rather core to the emissions estimates of this project. There are at least two inconsistencies in the RDEA that render it incorrect: first, the likely marginal generation resource for of energy consumption at the capture facility is Milton Young itself; and second, even assuming the capture facility will be run on marginal market-based energy generations, the RDEA's estimation of emission rates associated with that energy is incorrect. We address these in reverse order, below.

a) <u>The RDEA's market-based emissions rate appears to be incorrectly calculated or rely on an incorrect set of assumptions</u>

According to the RDEA Life Cycle Analysis (Appendix F), the CO_2 emissions rate associated with electricity consumption and steam consumption at Project Tundra are 265 kg/MWh and 285 kg/MWh, respectively, and states that it is based off of the "historic Minnkota System."[27] This emissions rate of approximately 0.3 tCO_2/MWh is commensurate with a system that is largely low emissions–*i.e.* not that of Minnkota. According to Minnkota's 2023 annual report, the

[25] RDEA at 3-9.
[26] Assuming that DOE meant that these units should be megawatt-hours (MWh) and units of energy output per day, rather than capacity (MW).
[27] RDEA at Appendix E, E-13.

9

5-5 (cont'd) utility's generation portfolio is 57% coal, 34% wind, 7% hydroelectricity, and 2% "other."[28] With an uncontrolled CO_2 emissions rate of 1,134 kg CO_2/MWh (or 1.25 tCO_2/MWh) at Milton Young,[29] Minnkota's system likely has an aggregate emissions rate of 646.4 kg CO_2/MWh (or 0.71 tCO_2/MWh). As a first matter, the RDEA should have calculated that *Minnkota's system emissions rate is 244% greater* than the factors used in the life cycle assessment.

However, even the erroneously lower emissions rate used by the RDEA is then factored incorrectly or incomplete. According to the final RDEA, electricity consumption associated with the CCS unit accounts for just 49.90 kg CO_2/MWh.[30] However, according to the life cycle analysis appendix, the total emissions from electricity and steam consumption (which may not have been accounted for) amount to a total of 453 million kg per year,[31] spread over approximately 5 million MWh per year,[32] or an emissions rate of 90 kg/MWh. The RDEA total emissions estimate *incorrectly assumes that only electricity requirements produce additional emissions*, and does not include the steam requirements, which are also parasitic on Milton Young and will increase energy inputs and corresponding emissions.

According to the RDEA's response to comments, "although steam is expected to be sourced directly from MRY, the heat rate at the plant will remain unchanged regardless of the operation (or lack of operation) of the CCS."[33] This is an inaccurate portrayal of the operations of CCS. Harnessing steam from a coal boiler deprives the steam turbine of its energy source, which substantially decreases the amount of energy that can be harnessed at the turbine. Keeping the fuel input (MMBtu) the same and decreasing the amount of resulting energy (MWh) mathematically increases the heat rate (in MMBtu/MWh) and decreases the efficiency of the unit overall. Harnessing steam from the coal unit would require that the total output of the plant decreases. Even if the CCS island is considered a separate customer, the coal unit would not be able to sell the same amount of electricity when a substantial amount of steam is pulled from the boiler.

Taking both the parasitic electricity and steam consumption requirements of the carbon capture equipment into account and using Minnkota's actual generation portfolio and average emissions, the resulting energy consumption emissions should be closer to 211 kg/MWh, making the total CO_2 emissions in Table 3-7 closer to 573 kg/MWh, or more than half of the CO_2 emissions of the Milton Young Plant in the "No Action" scenario. This is a substantially different emissions factor than used in the RDEA.

[28] Minnkota Power Cooperative, Minnkota Power Cooperative: Powerful Voices 2023 Annual Report, (2023), *available at* https://assets.website-files.com/5ef212e2cdca1e094063db4e/6616d1b16d247b52a3ca29dc_MPC-2023%20Annual%20Report-Web.pdf, at 47 (PDF 24).
[29] RDEA at Table 3-9: No Action, Initial Life Cycle Analysis Results (kg of emissions / MWh), 3-13.
[30] *Id.* at Table 3-7: Proposed Action, Initial Life Cycle Analysis Results (kg of emissions / MWh), 3-11.
[31] *Id.* at Appendix E, E-13, addition of 178.8 million kg and 274.4 million kg in electricity and steam consumption tables.
[32] *See id.* at Appendix E, E-11, YOUNG Boiler 1 and Boiler 2 in 2028, for example.
[33] *Id.* at Appendix K, K-28.

10

5-5 (cont'd)

b) The RDEA uses emissions from market-based energy sources whereas energy consumption at Project Tundra will largely be from the high-emissions coal plant itself.

The technical specifications of Project Tundra as presented in both Minnkota's public materials as well as the FEED study conducted by DOE both assess that the electricity *and* the steam load required to run Project Tundra will be sourced from either the coal plant itself or a purpose-built gas power plant and boiler, not market energy. The ramifications of these alternatives are higher emissions than characterized in the RDEA.

According to the RDEA's response to comments,

> Energy use associated with the CCS has been incorporated in the revised Initial LCA project scope (Summary Comment 20) and has been incorporated as a new emission category. As an independent operation, the CCS system owners have chosen to purchase the electric and steam energy needed from Minnkota's electricity system. The steam and electricity offering to the CCS system is on terms and conditions similar to other large, unique loads on their system (e.g., computing and server centers). For the Initial LCA analysis, it is assumed that steam will be sourced directly from MRY following terms as agreed upon by the CCS system owners and Minnkota. Similarly, it is assumed that the CCS system will receive electricity from the Minnkota electricity system (*i.e.,* grid) that includes multiple generation sources.[34]

As a first matter, the RDEA inappropriately seeks to dismiss the impact of steam load required to operate the CCS. The steam load sourced at the coal unit must be characterized as an emissions source for its degradation of the coal unit's output. According to DOE's FEED study, the thermal load (*i.e.* steam) was scoped as sourced from either a separate methane gas boiler,[35] or directly from steam at Unit 2.[36] In both cases, the extraction of energy from steam results in a fuel cost and resulting emissions. This could either be characterized as a net decrease in the generation of Milton Young (decreasing the MWh in Table 3-7, and increasing the commensurate emissions) or in a more complicated manner attempting to account for the emissions of that steam separately.

As a second matter, the assumption that "the CCS system will receive electricity from the Minnkota electricity system (*i.e.* grid)..." and then characterization of resulting emissions as market-based is a misrepresentation, or a shell game. The CCS equipment of Project Tundra

---

[34] *Id.* at Appendix K, K-28.

[35] *See* Project Tundra, "Front-End Engineering & Design: Project Tundra Carbon Capture System," (May 22, 2023), *available at* https://netl.doe.gov/projects/files/Front-End%20Engineering%20and%20Design%20Project%20Tundra%20Carbon%20Capture%20System.pdf at 12 ("Process 100% of flue gas from Young 2 and natural gas-fired boilers"), 15, 18, 19 (enclosures, including "[b]oiler enclosure" and "gas boilers" away from coal plant), 21 (thermal load in MMBtu/day, "natural gas input"), 25 "Pre-FEED selection of natural gas-fired package boilers… Required three 33% boilers," and "Larger CCS to handle flue gas from package boilers") (hereinafter "Project Tundra FEED Presentation").

[36] *Id.* at 26 ("FEED Steam Source Selection Design/Cost from Two Supply Options").

11

5-5 (cont'd) requires a substantial amount of electricity to operate. The idea that Project Tundra, part of an electrical generator, would assume that electricity required to operate a part of the plant comes from off-system–and therefore allocate emissions off-system–is absurd.[37] In standard utility practice, electricity used at a generation facility–for pumps, fans, lights, and emissions controls–are considered "auxiliary loads," as is the case in Project Tundra's FEED study.[38] Those loads are considered to be part of the operations of the plant itself, and therefore reduce net plant output.[39]

This NEPA assessment seeks to review emissions as a function of delivered electricity,[40] and thus it is critical to characterize delivered electricity appropriately. As a system, Project Tundra and Milton Young produce less delivered electricity due to the extraction of steam and use electricity to operate the CCS unit. Therefore, the emissions on a per MWh produced must be higher, due to the lower denominator.

RDEA Tables 3-9 and 3-7 show at-site CO_2 emissions from Project Tundra as 1,134 $kgCO_2$/MWh without CCS and 410.8 $kgCO_2$/MWh[41] with CCS, respectively. Accounting for auxiliary load, the CCS proposed action should show at least 754 $kgCO_2$/MWh net, or nearly twice the CO_2 emissions rate shown here.[42]

5-6

2. The RDEA assumes that the capture unit will not impact the operations or dispatch of the underlying coal unit, inconsistent with economics of the 45Q tax credit and EPA's assumptions

In multiple instances, the RDEA states that Project Tundra will have no impact on the operation or dispatch of Milton Young,[43] a statement which is demonstrably false. If the CCS unit causes the power plant to operate more often, then the emissions benefit of the CCS would be

---

[37] An equivalent absurd scenario might be if the proposed action was the construction of a new, uncontrolled power plant, with an assumption that the utility would also contract for an equal amount of renewable energy, and assess that the proposed action only had half the emissions rate of a coal-fired power plant because of the assumed emissions free energy. The proposed action has no bearing on if Minnkota also buys a commensurate amount of grid-based energy to offset the energy lost at Project Tundra to auxiliary load, and is therefore inappropriate as an assumption.

[38] Project Tundra Feed Presentation at Table 17, 20. ("Total thermal and electrical auxiliary loads").

[39] *See, e.g.* National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," (Oct. 14, 2022), *available at* https://www.osti.gov/servlets/purl/1893822/, at 30 ("...the capture cases have a higher auxiliary load requirement than non-capture cases, which serves to further reduce net plant output") (hereinafter "NETL Baseline Vol 1").

[40] RDEA at § 3.3.2.1, 3-7 ("The Initial LCA has been defined as kilograms (kg) of CO_2 stored and as megawatt-hours (MWh) delivered to the grid").

[41] MRY coal plant + CO_2 capture plant + electricity consumption.

[42] In 2032, MRY is projected to produce 5.02 million MWh and 6.28 million short tons CO_2 without carbon capture (at 1,134 kg/MWh). If the project captures 4 million tons per year, it would emit 2.28 million tons CO_2. According to RDEA Appendix E-13, the project would consume an estimated 0.675 million MWh in electricity and 0.964 million MWh equivalent of steam load, reducing net output to 2.74 million MWh. The resulting emissions rate is 0.83 tCO_2/MWh net, or 754 kg CO_2/MWh net.

[43] RDEA at Appendix K, K-11, Summary Comment 11 ("The CCS unit is structured physically and commercially to have no impact on the operation or dispatch of the MRY (see response to summary comment 9). Because the dispatch of the power plant is forecasted based on its market position, and because the project sponsors have structured the CCS project to not impact power plant economics, including impacts due to available tax credits, then in both the "no build" and the "build" cases under the LCA, the dispatch should be the same").

12

5-6 (cont'd) diminished. And this is, in fact, the likely outcome of installing CCS due to the nature of the 45Q tax credit.

Under today's conditions, Milton Young has a marginal operating cost between $27-31/MWh,[44] which means that in 2023 it would have ideally operated at around a 44% capacity factor to minimize losses during low market price conditions (*i.e.* "to accommodate [zero marginal cost] wind power in the region"[45]). In other words, rather than having generated nearly 5 million MWh (gross) and 5.5 million tons CO_2 in 2023,[46] it should have generated around 3 million MWh–and just 3.3 million tons CO_2.

However, as previously noted, the 45Q tax credit acts as a production tax credit and a substantial subsidy for operations. Indeed at $85/ton CO_2, the 45Q tax credit represents a marginal cost subsidy of over $100/MWh. Even accounting for the parasitic or auxiliary load of CCS and the costs of operating the CCS unit, this tax credit reduces the marginal cost of operations to a *negative* value. Simply put, once a CCS unit is installed, the value proposition of burning the next unit of coal in order to sequester some of the carbon and earn a tax credit is far too valuable to not operate. It is highly likely that CCS-retrofit power plants will operate as often as feasible.

At Milton Young / Project Tundra, the CCS unit will incentivize the operations of the power plant and likely result in around-the clock production.[47] The FEED study for Project Tundra assumes an 85% capacity factor, which in effect means operating as often as feasible, but for outages. Even if Project Tundra captured 4 million tons per year, Milton Young would still emit 2.4 million tons CO_2. If this project were to have been in operation in 2023, and Milton Young operated cost effectively in both conditions, it would emit 3.3 million tons CO_2 in the base case, and 2.4 million tons in the CCS case, or just a 28% reduction relative to the baseline.

5-7 **IV. Summit Carbon Solutions Carbon Express pipeline network**

The RDEA's response to commenters' initial comments optimistically states that this project, if connected to a pipeline network, would only *accept* carbon dioxide from the proposed Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project (Summit Pipeline).[48] Without any information on how this could be designed to be a one-way pipeline, the response to initial comments merely states that using the captured MRY carbon dioxide would not meet the "objective" of this funding and therefore wouldn't be consistent with the funding.[49] This argument is tautological and merely wishful thinking. Indeed, the RDEA in no way describes any assurance, build specifications, legal limitations, or other enforceable controls that would stop

---

[44] Based on a 2023 delivered coal cost of $1.95/MMBtu (EIA Form 923), heat rate of ~12 MMBtu/MWh (EIA Form 923) and assumed variable operating cost of between $3.5-$7.7/MWh (*see* NETL Baseline Vol 1, at Case B12A, 483).

[45] RDEA at Appendix K, K-10.

[46] U.S. EPA, Clean Air Markets Program Database, (Q4 2023), *available at* https://campd.epa.gov/.

[47] Knight, P. and J. Smith,"Clearing the Air on Coal CCS: New tax credits make partial CO_2 capture viable, potentially increasing emissions," (Oct. 21, 2022), *available at* https://www.reginfo.gov/public/do/eoDownloadDocument?pubId=&eodoc=true&documentID=218396.

[48] RDEA at Appendix K, K-7.

[49] *Id.*

13

5-7 (cont'd) this project from sending captured carbon dioxide to serve enhanced oil recovery (EOR) once it is connected to the Summit Pipeline.

Recent reporting and statements, under oath, by Summit's representatives indicate that its project will be used for EOR. In written testimony to the North Dakota Public Service Commission, Dan Pickering, a consultant providing financial and economic expertise to Summit, assured the regulators that the project would serve EOR and extend the environmental impacts of oil extraction in North Dakota. In response to a question about how the Summit Pipeline will serve state energy needs, Mr. Pickering testified:

> It is likely that more CO_2 will enter North Dakota over time. This CO_2 can support Enhanced Oil Recovery projects (EOR) in the Bakken Shale and conventional fields to generate higher recovery/production volumes and extend the life of these fields. This should result in sustaining or enhancing the benefits currently being generated for the state/population by the energy industry.[50]

In live testimony, and under penalty of perjury, Mr. Pickering suggested that the figures he provided in his written testimony should "be considered minimums" and that the actual impact of the Summit Pipeline would likely be much larger than he had initially estimated.[51] His most explicit example of this was that instead of consuming four million dollars of electricity annually, the project would now consume fourteen million dollars worth of electricity.[52] In addition to landowners receiving payoffs for injection under their ground, and electrical use, Mr. Pickering testified further on the opportunities presented by the Summit Pipeline, stating again that additional carbon in the Summit Pipeline will mean additional EOR in North Dakota.[53]

Mr. Pickering's testimony is consistent with Summit's statements to potential clients that its system will be used both for carbon injection without EOR, and for EOR when a customer wants to transport its carbon for that purpose.[54]

Even if DOE had committed to an actual enforceable limit on using Milton Young / Project Tundra's carbon dioxide for EOR, the connection of this project to the Summit Pipeline has the cumulative effect of promoting EOR in North Dakota for decades to come. This is because DOE

---

[50] North Dakota Public Service Commission, *In the Matter of the Application of SCS Carbon Transport LLC for a Certificate of Corridor Compatibility and Route Permit for the Midwest Carbon Express Project in Burleigh, Cass, Dickey, Emmons, Logan, McIntosh, Morton, Oliver, Richland and Sargent Counties, North Dakota*, Direct Testimony of Dan Pickering, (Apr. 22, 2024), ***available at*** https://www.psc.nd.gov/database/documents/22-0391/528-010.pdf, at 6:4-6:8.

[51] North Dakota Public Service Commission, PU-22-391.535 Electronic Recording of 22 April 2024 Formal Hearing, (Apr. 22, 2024), ***available at*** https://apps.psc.nd.gov/webapps/cases/psdocketdetail?getId=22&getId2=391&getId3=535, at time stamp 22:40.

[52] *Id.* at time stamp 22:47.

[53] *Id.* at time stamp 30:35.

[54] Leah Douglas, "US carbon pipeline company pledges no oil recovery, but Bakken drillers want it," (Mar. 11, 2024), ***available at*** https://www.reuters.com/markets/carbon/us-carbon-pipeline-company-pledges-no-oil-recovery-bakken-drillers-want-it-2024-03-11/ ("But Summit has a different message for prospective clients, including North Dakota's oil sector, according to a Reuters review of state regulatory filings and recordings of public appearances by company executives: if you want to use our project for enhanced oil recovery (EOR), where gas is pumped into oil fields to increase production, just write a check").

14

5-7 (cont'd) funding will help to make both projects viable, and by connecting to the Summit Pipeline this project will provide certainty (not to mention valuable pressure in the line) to the Summit Pipeline, allowing more barrels of carbon dioxide to be transported to the oil fields. It is naive to assume that this project will never provide carbon dioxide for EOR when the pipeline literally takes captured CO_2 from Project Tundra the short remaining distance to the oil fields of the state, while it is the avowed public policy of North Dakota to use any carbon dioxide it can get for EOR.[55] Even if that naivete were justified by actual controls on the fungible product Project Tundra will be able to put in the Summit Pipeline, the significant public funding and financial certainty that DOE is providing to this project will accrue to the Summit Pipeline as well.

As a result, a full EIS should be prepared to account for the additional climate, land, and localized air pollution impacts that will be caused by the cumulative impacts of this funding extending EOR and oil production in North Dakota, and oil use throughout the country.

5-8 **V. Water Use**

The RDEA is accompanied by responses to initial comments that states "The 15,000 acre-feet of water requested for the project is 0.10 percent of the mean annual discharge recorded at Garrison Dam and the requested withdrawal rate of 13,480 gallons per minute, or 30.0 cubic feet per second, is 0.14 percent of the mean daily discharge rate." The response goes on to conclude that "the proposed project does not represent a significant change to daily flow or annual discharge."[56] The RDEA similarly suggests that this amount of water is not significant compared with the entire flow of the Missouri River. This conclusion and comparison are absurd when looked at objectively.[57]

The RDEA's logic would suggest that any water usage that is not sufficient to permanently change the *annual* flow of one of the *largest* rivers in the United States is somehow inherently insignificant. This conclusion ignores the fact that rivers are not perfectly uniform all year long and that the project's water usage will likely not be uniform while running the carbon capture system. Water stress in this region can be the worst in the summer months when agricultural needs are greatest.[58] This has been the case in several of the past years,[59] suggesting that using annual average numbers to understate potential impacts and their significance is overly simplistic.

[55] Dave Thompson, "Helms: ND will need more CO2 for enhanced oil recovery," (Aug. 17, 2023), *available at* https://news.prairiepublic.org/local-news/2023-08-17/helms-nd-will-need-more-co-for-enhanced-oil-recovery.

[56] RDEA at Appendix K, K-13.

[57] *Id.* at 3-34.

[58] U.S. NOAA, National Centers for Environmental Information, Annual 2023 Drought Report, (Jan. 12, 2024), *available at* https://www.ncei.noaa.gov/access/monitoring/monthly-report/drought/202313 (In 2023 "Nationwide, July was driest with more than a fifth of the [continental United States] very dry." The Midwest experienced significant drought variability as well, and was reportedly "dry May-June, September, and November, with parts dry in July-August and December; wet in parts January-March, April, July, October, and December").

[59] In both 2021 and 2023 the Minnesota authorities were forced to restrict surface water appropriations with official Drought Restrictive Phase announcements for certain rivers. *See* Minnesota DNR, Brief Summary of State Drought Task Force Meeting, (Aug. 19, 2021), *available at* https://content.govdelivery.com/accounts/MNDNR/bulletins/2ef378e; Minnesota DNR, News release: Drought continues to deepen in Minnesota, (Sept. 8, 2023), *available at* https://www.dnr.state.mn.us/news/2023/09/08/drought-continues-deepen-minnesota.

15

5-8 (cont'd) The RDEA's discussion of water impacts fails to take a hard look at the foreseeable impacts of this large new water use on existing river water users in the months of most stress on the hydrological system.

Additionally, comparing this project's usage to the entire river flow is a false comparison akin to saying no air pollution source can have climate impacts because the atmosphere is so large, or that no water pollution discharge can impact ocean life because oceans are vast. The Ninth Circuit has previously found an Environmental Assessment inadequate when it purported to dismiss impacts as insignificant by juxtaposing them with a global total, characterizing such a comparison as "opaque."[60]

Commenters do not dispute the fact that the Missouri River is very large, but that is not the point. The point is that this project would newly appropriate 15,000 acre-feet of water for industrial use in a state that recently only permitted 60,494 acre-feet of industrial surface water use.[61] This is an increase of 24.8 percent over historic industrial surface water use for the *entire state* of North Dakota. As already stated by commenters, this is an increase of 4,887,771,428.6 gallons appropriated from the Missouri River every year. That means that, according to EPA figures, this project would use the same amount of water as 163,307 average Americans.[62] That is more than the entire population of Fargo, not to mention every other city in the state of North Dakota.[63] It is absurd to say that one project with the impact of a city larger than any in the state where the project is proposed would have an insignificant impact on water availability. The foreseeable water need of this project necessitates an EIS.

VI. Commenters

The Sierra Club is a national nonprofit organization with 67 chapters, including chapters in North Dakota and Minnesota, and more than 832,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. In North Dakota, we have nearly 3,000 members and supporters; in Minnesota, we have nearly 57,000. Our goals include restoring clean air and water, providing affordable clean energy, supporting family-sustaining jobs, and addressing inequities in our response to climate

60 *350 Montana v. Haaland*, 50 F.4th 1254, 1269 (9th Cir. 2022); *see also* 40 C.F.R. § 1508.27 ("[T]he significance of an action must be analyzed in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality").

61 North Dakota Water Resources, Biennial Report: July 1, 2019 - June 30, 2021, (Mar. 28, 2022), *available at* https://www.swc.nd.gov/info_edu/reports_and_publications/biennial_reports/pdfs/2019-2021.pdf, at 36 (showing 60,494 acre-feet of approvals from 2019 to 2021).

62 U.S. EPA, WaterSense, Statistics and Facts, (Apr. 2, 2024), *available at* https://www.epa.gov/watersense/statistics-and-facts (an average American uses 82 gallons per day, multiplied by 365 equals 29,930 gallons, and 4,887,771,428.6 divided by 29,930 is 163,306.7634012696–commenters have rounded this figure up slightly, to avoid positing a partial American).

63 North Dakota Demographics, North Dakota Cities by Population, (Dec. 7, 2023), *available at* https://www.northdakota-demographics.com/cities_by_population (Fargo's population: 127,319); World Population Review, North Dakota Cities by Population, (2024), *available at* https://worldpopulationreview.com/states/cities/north-dakota (Fargo's population in 2024 estimated at 136,909).

disruptions. A key component of meeting this goal is achieving 80% carbon pollution-free electricity by 2030.

CURE is rural-based, with staff across Minnesota. CURE knows rural people, lands, and ecosystems are vital to helping solve some of the biggest problems faced by Minnesota and the nation. We help to tell the story of a vibrant rural future, lift-up people to lead, and work for policies and laws to make a better future possible for everyone. CURE's work includes a long term focus on rural electric cooperative governance and evolution to advance a clean, healthy, and sustainable energy future. Minnkota Power Cooperative serves member co-ops in North Dakota and Minnesota, providing electricity to the rural Minnesotans that CURE hears from and works with on a regular basis. It is of paramount importance to CURE that the Department of Energy not shortchange these Americans with an inadequate environmental review.

Dakota Resource Council was founded in 1978 in order to protect North Dakota farms and ranches from widespread energy development. DRC's mission is to promote sustainable use of North Dakota's natural resources and family-owned and operated agriculture. To do this DRC builds member-led local groups that empower people to influence the decision-making processes that affect their lives and communities and protects the environment.

* * *

For the reasons identified herein, the RDEA continues to be in error, and the impacts of Project Tundra continue to be significant. DOE must correct the substantial errors in its analysis and conduct a full EIS before moving forward.

Respectfully submitted,

/s/ Hudson Kingston
Hudson B. Kingston
Legal Director
CURE, https://curemn.org/
117 S 1st Street
Montevideo, MN 56265
(320) 269-2984
hudson@curemn.org

/s/ Jeremy Fisher
Jeremy I. Fisher
Principal Advisor, Climate and Energy
Megan Wachspress
Staff Attorney
Sierra Club, https://www.sierraclub.org/
2101 Webster St., Suite 1300
Oakland, CA 94612

(415) 977-5536
jeremy.fisher@sierraclub.org
megan.wachspress@sierraclub.org

/s/Scott Skokos
Scott Skokos
Executive Director
Dakota Resource Council
(406) 850-9755
scott@drcinfo.com