# BNI Coal Ltd.

# Tract 1 Federal Coal Lease-by-Application

# Serial Number: NDM-102083

# Environmental Assessment

# June 2020

**US Department of the Interior**

**Office of Surface Mining Reclamation and Enforcement**

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## Acronyms

| Acronym | Definition |
|---|---|
| $\mu g/m^2/yr$ | micrograms per square meter per year |
| AAQM | Ambient Air Quality Monitoring |
| AQRV | air quality-related values |
| ASLM | Assistant Secretary for Land and Minerals Management |
| BLM | Bureau of Land Management |
| BNI | BNI Coal Ltd. |
| C.F.R. | Code of Federal Regulations |
| CAA | Clean Air Act |
| $CH_4$ | methane |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2e$ | $CO_2$ equivalent |
| DEQ | Department of Environmental Quality |
| DOI | Department of the Interior |
| dv | deciviews |
| EA | Environmental Assessment |
| EIS | Environmental Impact Statement |
| ESA | Endangered Species Act |
| FLIGHT | Greenhouse Gasses Tool |
| FONSI | Finding of No Significant Impact |
| ft | feet |
| GHG | greenhouse gases |
| $H_2S$ | hydrogen sulfide |
| HAPs | hazardous air pollutants |
| IAMs | Integrated Assessment Models |
| IMPROVE | Interagency Monitoring of Protected Visual Environments |
| IPCC | Intergovernmental Panel on Climate Change |
| km | kilometers |
| lb/yr | pounds per year |
| LBA | lease by application |
| m | meters |
| MACT | maximum available control technology |
| MeHg | methylmercury |
| Minnkota | Minnkota Power Cooperative, Inc. |
| MLA | Mineral Leasing Act |
| MMT | million metric tons |
| MPDD | mining plan decision document |
| $N_2O$ | nitrous oxide |
| NAAQS | National Ambient Air Quality Standards |
| NADP | National Atmospheric Deposition Program |
| NDAC | North Dakota Administrative Code |
| NEI | National Emission Inventory |
| NEPA | National Environmental Policy Act |
| NHPA | National Historic Preservation Act |
| $NO_2$ | nitrogen dioxide |
| $NO_X$ | nitrogen oxide |

| Acronym | Definition |
|---|---|
| NPS | National Park Service |
| $O_3$ | ozone |
| OMB | Office of Management and Budget |
| OSMRE | Office of Surface Mining Reclamation and Enforcement |
| Pb | lead |
| $PM_{10}$ | particulate pollution |
| $PM_{2.5}$ | particulate pollution |
| PSC | Public Service Commission |
| PSD | Prevention of Significant Deterioration |
| R2P2 | Resource Recovery and Protection Plan |
| RCP | representative concentration pathways |
| RHR | Regional Haze Rule |
| SCC | *social cost of carbon* |
| SIP | state implementation plan |
| SMCRA | Surface Mining Control and Reclamation Act |
| $SO_2$ | sulfur dioxide |
| U.S.C. | United States Code |
| US | United States |
| USEPA | US Environmental Protection Agency |
| USGCRP | US Global Change Research Program |
| USGS | U.S. Geological Survey |
| VOC | volatile organic compounds |

# Chapter 1
# Introduction

## 1.1 Introduction

BNI Coal Ltd. (BNI), operator of the Center Mine in North Dakota, proposed lease by application (LBA) for federal coal resources underlying private surface lands within the permit area of the Center Mine in Oliver County, North Dakota. The lease area, known as Tract 1 (serial number NDM-102083; Figure 1-1), is composed of private surface lands and federal minerals managed by the Bureau of Land Management (BLM). BNI's final LBA was submitted to BLM on November 6, 2014. The application area (i.e., Tract 1 [NDM-102083]) is located within the permit area of the Center Mine (BNI mining permit boundary in Figure 1-1), which was approved in 2014 by the North Dakota Public Service Commission (PSC) (Permit BNCR-1101).

Pursuant to Section 503 of the Surface Mining Control and Reclamation Act (SMCRA), which grants states the right to assume jurisdiction over the regulation of surface coal mining of non-federal coal, the North Dakota PSC developed a permanent regulatory program. In August 1983, pursuant to § 523(c) of SMCRA, the PSC entered into a cooperative agreement with the Secretary of the Interior to assume that jurisdiction. The PSC maintains primacy to enforce performance standards and permit requirements and has authority during environmental emergencies, while the Office of Surface Mining Reclamation and Enforcement (OSMRE) retains oversight of this enforcement. OSMRE is the agency responsible for making a recommendation to the United States (US) Department of the Interior (DOI) Assistant Secretary for Land and Minerals Management (ASLM) to approve, disapprove, or approve with conditions the proposed mining plan.

The BLM North Dakota Field Office completed an Environmental Assessment (EA) in June 2018 that analyzed the environmental impacts of a federal coal lease proposed by BNI located in the northeast ¼ of Section 8, Township 141 North, Range 83 West, Oliver County, North Dakota (Figure 1-1). The USDOI, OSMRE, Western Region Office and PSC cooperated in the preparation of the EA (Refence (1)). As a federal agency, OSMRE is subject to the National Environmental Policy Act of 1969 (NEPA), and therefore must conduct an environmental review, in the form of either adoption of a prior NEPA document for the same project, supplementing a prior NEPA document for the same project, or creation of a new NEPA analysis, before proceeding the federal action of making a recommendation to ASLM regarding the mining plan. OSMRE determined that the Proposed Action of mining a new federal coal lease constitutes a mining plan decision requiring approval by ASLM. OSMRE's decision was based upon consideration of the federal regulations at 30 Code of Federal Regulations [Code of Federal Regulations (C.F.R.)] Parts 740 and 746. OSMRE will begin developing a mining plan decision document (MPDD) recommendation which will be based on compliance with:

- NEPA;
- BLM's Resource Recovery and Protection Plan (R2P2) documentation;
- the LBA;

- the PSC permit findings; and
- and any documentation ensuring compliance with applicable requirements of other federal laws, regulations, and executive orders including consultation with the US Fish and Wildlife Service, and consultation on cultural resources.

The analyses regarding the affected environment, environmental impacts and mitigation, and cumulative effects for the following elements were addressed in BLM's 2018 EA (reference (1)):

- Cultural or Historical Values
- Geology and Minerals
- Noise and Vibration
- Socioeconomics
- Soils
- Vegetation Resources
- Water Resources (groundwater, surface water, water rights)
- Wetlands
- Wildlife, including migratory birds, raptors, and other special-status species

OSMRE incorporates by reference these analyses from BLM's 2018 EA, and they are not discussed further in this EA, in accordance with 40 C.F.R. 46.135. OSMRE prepared this EA based on new information provided by the Operator in order to further assess potential direct, indirect, and cumulative air quality and climate impacts associated with the approval of the federal mining plan.

OSMRE's review has been conducted in accordance with NEPA, as amended, and the President's Council on Environmental Quality regulations for implementing NEPA (40 (C.F.R.) 1500-1508); DOI regulations for implementation of NEPA (43 C.F.R. Part 46); DOI Departmental Manual Part 516; and OSMRE guidance on implementing NEPA, including the OSMRE Handbook on Procedures for Implementing the National Environmental Policy Act (Reference (2)).

NEPA requires federal agencies to consider the potential environmental impacts of proposed federal actions and to make a determination as to whether the analyzed actions would significantly impact the environment. The term "significantly" is defined in 40 C.F.R. 1508.27. If OSMRE determines that the project would have significant impacts following the analysis in the EA, then an Environmental Impact Statement (EIS) would be prepared. If OSMRE determines that the potential impacts would not be significant, OSMRE would prepare a "Finding of No Significant Impact" (FONSI) to document this finding, and, accordingly, would not prepare an EIS.

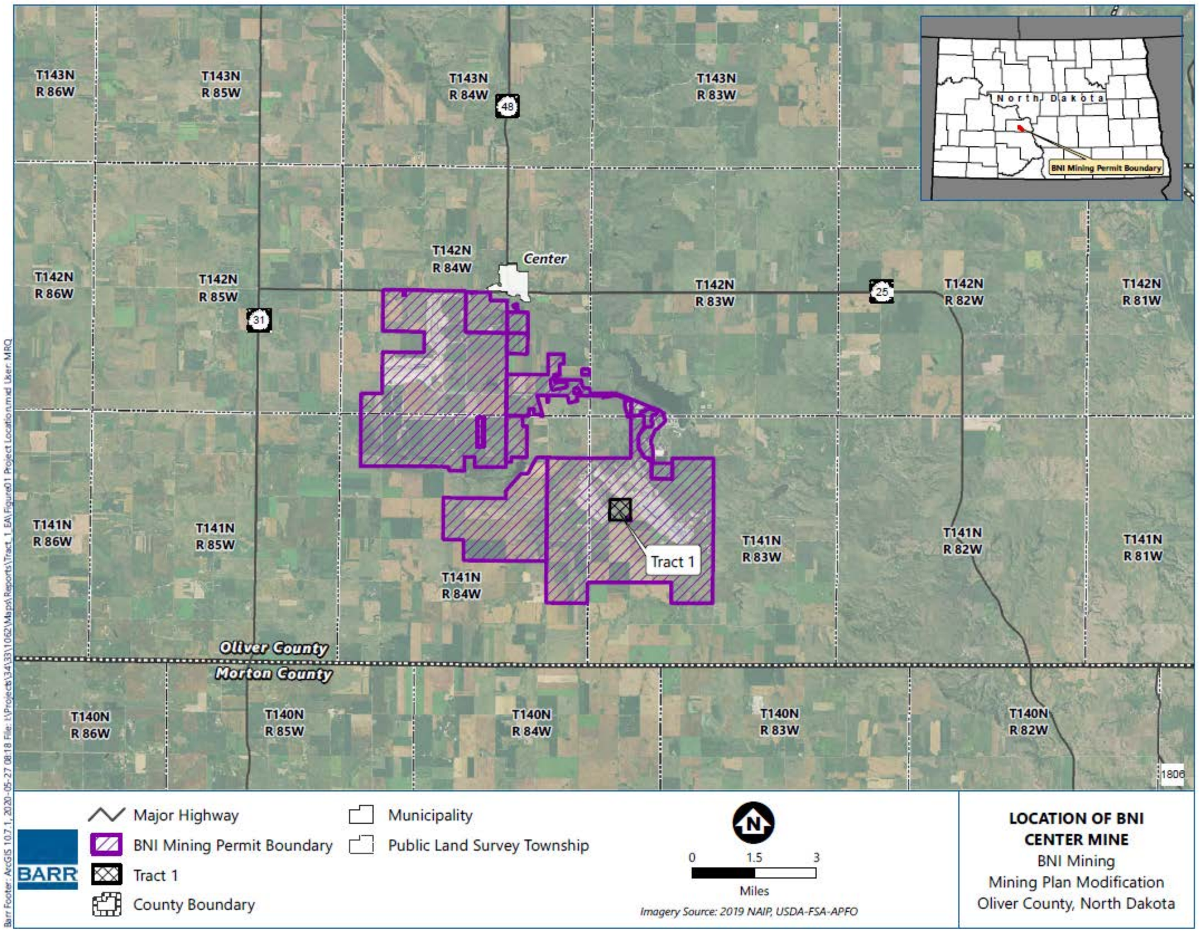



**Figure 1-1 Location of BNI Center Mine**

## 1.2 Background

BNI is the owner and operator of the Center Mine. BNI has been mining coal at the Center Mine since 1970, and the mine typically produces 4.0 to 4.6 million tons of lignite coal per year. Virtually all coal from the Center Mine is supplied to the Milton R. Young Station coal-fired power plant located adjacent to the northeast corner of the permit area. Minnkota Power Cooperative, Inc. (Minnkota) owns and operates the Milton R. Young Station that consists of two generating units. BNI is under contract to supply coal to the Milton R. Young Station through 2037. In addition, BNI supplies approximately 60,000 tons of coal to Center Coal Co. which is also located adjacent to the mine offices. Center Coal Co. is a supplier of stoker and lump coal to customers in North Dakota, South Dakota, Minnesota, and Canada (reference (3)).

The Center Mine is currently producing coal from two federal leases (NDM-97633 and NDM-95104) within mining permit BNCR-9702. Since 1970, lower stripping ratios have facilitated the economic recovery of coal at the mine. However, the ratios have steadily increased and currently in areas exceed 10:1. With increasing stripping ratios, coal quality constraints, and the amount of coal needed to fulfill the existing contract, BNI determined that a second mining area (permit BNCR-1101, an 8,360.72-acre area that includes Tract 1 [NDM-102083]) was necessary. Mining may continue in the current area (BNCR-9702) through 2025, pending other federal lease applications, and through 2037 in the new mining area (BNCR-1101). In June 2014, BNI began construction of infrastructure in the BNCR-1101 mining area, including haul roads, access corridors, sediment ponds and diversions, and power distribution. Mining of private reserves was initiated in this area in early 2015.

On November 6, 2014, BNI submitted the LBA to BLM for the leasing of federal coal resources in Oliver County, North Dakota. The application area (i.e., Tract 1 [NDM-102083]) is located within the permit area of the Center Mine (Figure 1-1), which was approved in 2014 by the PSC (Permit BNCR-1101). The BLM issued a federal coal lease for Tract 1 (NDM-102083) on January 1, 2019.

BNI estimates that there are approximately 2.43 million tons of minable coal in Tract 1 (NDM-102083). BNI's estimate that approximately 1.69 million tons of coal is recoverable is based upon its recent experience mining in the BNCR-1101 permit area. If this 1.69 million tons is mined in a continuous manner, it would represent approximately five months of coal production at the Center Mine at a mining rate of 4.0 million tons per year. However, the mine sequence of Tract 1 (NDM-102083) would take place in small tonnages over a 7-year period. The projected mine life and operating plans of the Center Mine, whether the ASLM approves the federal mining plan for Tract 1 (NDM-102083) or not, are anticipated to extend through the year 2037.

BNI has the appropriate surface leases to conduct surface activities (including surface disturbance and overburden removal) on the privately-owned surface overlying Tract 1 (NDM-102083) and, to the extent necessary for conducting mining operations, on the adjoining parcels where the surface and coal is privately owned. However, before coal removal can occur on Tract 1 (NDM-102083), the ASLM must approve the federal mining plan covering Tract 1 (NDM-102083), as required by 30 C.F.R. 746.11. BNI has an access agreement with the private landowner that has allowed BNI to conduct surface-disturbing preparatory work on the private lands overlying Tract 1 (NDM-102083), and PSC has permitted these surface-disturbing activities as well. The northwest portion of Tract 1 (NDM-102083) has already been disturbed with a stockpile and a mobile equipment building to support mining of private coal in the adjoining sections. A substation and drainage control feature are located in the northeast portion of Tract 1 (NDM-102083), and an existing farmstead site on the land overlying Tract 1 (NDM-102083) is being used for associated mining operations because BNI owns the buildings.

### 1.2.1 Milton R. Young Station

The OSMRE Handbook on Procedures Implementing NEPA defines connected actions as follows:

> Connected actions are those actions that are "closely related' and should be analyzed in the same NEPA document (40 C.F.R. 1508.25(a)(1)). Actions are connected if they automatically trigger other actions that may require an EIS; cannot or will not proceed unless other actions are taken previously or simultaneously; or if the actions are interdependent parts of a larger action and depend upon the larger action for their justification. (Reference (2))

The Milton R. Young Station is not considered a connected action to this Proposed Action because (1) it would not automatically trigger any action at the Milton R. Young Station that would require an EIS; (2) OSMRE can process approval without any changes (previous or simultaneous actions) at the Milton R. Young Station; and (3) OSMRE approval is not an interdependent part of a larger action at the Milton R. Young Station and does not depend on the plant for its justification because the coal could be sold elsewhere. However, if the coal is not sold to the Milton R. Young Station, BNI would need to find a new buyer for the approximately 1.69 million tons of coal proposed to be mined from Tract 1 (NDM-102083). If the coal were to be sold elsewhere, the potential buyer would depend upon market conditions at the time of the sale, which cannot be predicted at this time. Therefore, this option was not analyzed as a separate alternative.

The Proposed Action would not change production levels at the Milton R. Young Station or require changes to its current regulatory permits. If the mining plan is rejected, the Milton R. Young Station would continue to operate and be supplied with coal from other Center Mine production areas. The Milton R. Young Station would operate as needed and independent of the coal in Tract 1 (NDM-102083). Although the Milton R. Young Station is not considered a connected action, operating and emissions data from the power plant are included in this EA to provide context and to assist with analysis of the indirect effects of combustion of coal sourced from Tract 1 (NDM-102083).

## 1.3 Regulatory Framework and Necessary Authorizations

The following key laws, as amended, establish the primary authorities, responsibilities, and requirements for developing federal coal resources:

- Mineral Leasing Act of 1920 (MLA);
- National Historic Preservation Act of 1966;
- National Environmental Policy Act of 1969 (NEPA);
- Clean Air Act of 1970 (CAA);
- Clean Water Act of 1972;
- Endangered Species Act of 1973; and
- Surface Mining Control and Reclamation Act of 1977 (SMCRA).

SMCRA provides the legal framework for the federal government to regulate coal mining by balancing the need for continued domestic coal production with protection of the environment and society while also ensuring the mined land is returned to beneficial use when mining is finished. OSMRE implements its responsibilities for MLA and SMCRA under regulations at C.F.R. Title 30 - Mineral Resources, Chapter VII - OSMRE, DOI, Subchapters A-T, Parts 700-955.

SMCRA provides OSMRE primary responsibility for administering programs that regulate surface coal mining operations in the United States. Pursuant to Section 503 of SMCRA, 30 United States Code (U.S.C.) 1253, the PSC developed, and the Secretary of the Interior approved, North Dakota's permanent regulatory program authorizing PSC to regulate surface coal mining operations on private and state lands within North Dakota. Pursuant to Section 523 of SMCRA, 30 U.S.C. 1273, and 30 C.F.R. 934.30, PSC entered into a cooperative agreement with the Secretary of the Interior authorizing PSC to regulate surface coal mining operations on federal lands within the state.

Pursuant with this cooperative agreement, a federal coal leaseholder must submit a permit application package, which includes the R2P2 and State Mining Permit application, to OSMRE and PSC for any proposed coal mining and reclamation operations on federal lands located in the state. Federal lands include surface ownership and mineral interests, owned by the federal government. If the permit application complies with the relevant laws and plan, the PSC issues a permit to the applicant to conduct coal-mining operations.

OSMRE will prepare a mining plan decision document in support of its recommendation to ASLM, who will decide whether or not to approve the mining plan and whether or not additional conditions are needed. Pursuant to 30 C.F.R. 746.13, OSMRE's recommendation will be based on:

- the permit application package, including the R2P2;
- information prepared in compliance with NEPA, including this EA;
- documentation assuring compliance with the applicable requirements of federal laws, regulations, and executive orders other than NEPA;
- comments and recommendations or concurrence of other federal agencies and the public;
- findings and recommendations of BLM with respect to the R2P2, federal lease requirements, and MLA;
- findings and recommendations of PSC with respect to the permit application and the state program; and
- the findings and recommendations of OSMRE regarding additional requirements of 30 C.F.R. Chapter VII, Subchapter D.

## 1.4 Purpose and Need for the Proposed Action

The purpose of the action (to make a recommendation to the ASLM to approve, disapprove, or approve with conditions the proposed mining plan) is established by MLA and SMCRA, which requires the evaluation of BNI's application before they may conduct mining and reclamation operations to develop Tract 1 (NDM-102083) under 30 C.F.R. Part 746: 30, U.S.C. 208(c). OSMRE is the agency responsible for making a recommendation to the ASLM to approve, disapprove, or approve with conditions, the proposed mining plan. As approved in MLA, ASLM will decide whether the mining plan is approved, disapproved, or approved with conditions. The need for the action is to allow BNI the opportunity to exercise its valid rights granted for Tract 1(NDM-102083) to extract coal from its federal lease issued by BLM pursuant to MLA.

## 1.5 Outreach and Issues Identification

OSMRE developed a project website, which provided additional notice, information, and comment opportunities: http://osmtest/lrg/projects.shtm. The website was activated on June 25, 2020 and is updated periodically as additional information becomes available.

OSMRE released the EA and unsigned FONSI for a 15-day public comment period. OSMRE notified the public of this comment period through a newspaper notice published in the Bismarck Tribune and the Center Republican, mailed public outreach letters, as well as mailed tribal consultation letters to 18 tribal leaders.

# Chapter 2
# Proposed Action and Alternatives

## 2.1 Introduction

This chapter incorporates Chapter 2.0 of the BLM EA by reference and only provides supplemental information regarding air quality where relevant to the analysis presented in this document. Chapter 2.0 of the BLM EA describes the alternatives considered and analyzed in detail; the Proposed Action and the No Action. In addition, the BLM EA identifies the current operations, and continuation of activities under the Proposed Action and under the No Action. This section presents a description of the Proposed Action for which air quality is analyzed along with a description of the No Action alternative.

### 2.1.1 Proposed Action

Tract 1 (NDM-102083) is located in the northeast ¼ of Section 8, Township 141 North, Range 83 West, Oliver County, North Dakota and contained within BNI's permit (BNCR-1101), issued by the PSC for mining activities; however, no actual mining of the federal coal tract can occur until the mining plan is approved by the ASLM. BNI estimates that there are approximately 2.43 million tons of minable federal coal located in Tract 1 (NDM-102083), of which 1.69 million tons of coal is recoverable from the tract. Thus, the Proposed Action assumes the recovery of 1.69 million tons of coal (Table 2-1). If the 1.69 million tons are mined in a continuous manner, it would represent approximately five months of coal production at the Center Mine at a mining rate of 4.0 million tons per year. However, the plan recovery sequence for Tract 1 (NDM-102083) would take place over a 7-year period. The projected mine life and operating plans of the Center Mine, whether Tract 1 (NDM-102083) is mined or not, are anticipated to extend through the year 2037. The Proposed Action is for OSMRE to submit a MPDD making a recommendation to ASLM to approve the MPDD.

### 2.1.2 No Action

Under the No Action alternative, OSMRE would not recommend approval of the MPDD to ASLM. Without ASLM approval, the PSC's permit would revert to the previous permit. Under the previous permit, the federal coal reserves in Tract 1 (NDM-102083) would not be recovered and mining would continue until available coal reserves are mined out. Under the No Action alternative, additional soil removal and spoil stripping would occur on this tract under the state permit in order to support the mining of the adjoining private coal reserves, as well as, additional soil stockpiles would be required in support of mining on this tract. Beyond additional physical disturbances, a No Action alternative would also delay reclamation of the surrounding private lands.

**Table 2-1 Summary Comparison of Coal Production, Surface Disturbance, and Mine Life for the No Action Alternative and Proposed Action, as of December 31, 2019**

| Item | No Action Alternative | Federal Mining Plan Approval of the Proposed Action |
|---|---|---|
| Remaining Mineable Federal Coal | 5.1 Mt | 7.53 Mt<br>(2.43 Mt added) |
| Remaining Recoverable Federal Coal | 3.84 Mt | 5.53 Mt<br>(1.69 Mt added) |
| PSC Permit Area (Permit BNCR-1101) | 8,360.72 acres | 8,360.72 acres<br>(no change) |
| Currently Approved Federal Mine Plan Area | 0 acres | 160 acres<br>(160 acres added) |
| PSC Acres to Be Disturbed (Permit BNCR-1101) | 8,360.72 acres | 8,360.72 acres<br>(no change) |
| Average Annual Coal Production | 4.0 Mt | 4.0 Mt<br>(no change) |
| LOM Year (Permit BNCR-1101) | 2037 | 2037<br>(no change) |

### 2.1.3 Air Quality

BNI operates the Center Mine under a minor source air permit number O79004 (NDAC 33-15-14-03) from the North Dakota Department of Environmental Quality (DEQ). In accordance with its air permit, among other standards, BNI is required to comply with fugitive dust controls that include the following (Reference (4)):

1. *Control fugitive particulates from land clearing, topsoil and overburden removal, and other material-handling operations using strategies such as watering, revegetation, delay of topsoil disturbance until necessary, surface compaction, and sealing unless natural moisture is sufficient to control emissions.*
2. *Use fugitive dust preventative measures such as watering, covering, shielding, or enclosing stockpiles, both active and inactive, as necessary to control emissions unless natural moisture is sufficient to control emissions.*
3. *Fugitive dust preventative measures such as frequent watering, addition of dust palliatives, detouring, paving, closure, speed control, or surface treatment shall be used for on-site haul roads unless natural moisture is sufficient to control emissions.*
4. *Construct, protect, or treat all conveyors, transfer point, crushers, screens, and dryers to minimize particulate matter emissions.*

These requirements would apply to the BNI Center Mine in both the Proposed Action and the No Action.

# Chapter 3
# Affected Environment – Air Quality and Climate Change

## 3.1 Introduction

This chapter describes the existing condition of resources regarding air quality and climate change that could be affected by implementation of the alternatives described in Chapter 2.0, as they relate to the MPDD for BNI Center Mine. This chapter incorporates Chapter 3.0 of the BLM EA by reference and only provides supplemental information regarding air quality where relevant to the analysis presented in this document.

## 3.2 Air Quality and Climate Change

### 3.2.1 Criteria Pollutants and Air Quality Standards

The CAA requires the US Environmental Protection Agency (USEPA) to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. Primary standards provide public health protection including sensitive populations such as children, chronically ill, and elderly, while secondary standards provide public welfare protection (visibility, damage to crops, danger to animals, etc.). USEPA has set NAAQS for six principle pollutants, called criteria pollutants including carbon monoxide (CO), lead (Pb), nitrogen dioxide ($NO_2$), ozone ($O_3$), particulate pollution ($PM_{2.5}$ and $PM_{10}$), and sulfur dioxide ($SO_2$). Ozone is not emitted directly but is formed through atmospheric chemical reactions. Nitrogen oxides ($NO_x$) and volatile organic compounds (VOC) contribute to $O_3$ formation in the atmosphere and are regulated through equipment standards and emissions limits.

Geographic areas that do not comply with primary NAAQS requirements for criteria pollutants are considered nonattainment areas. A particular geographic region may be designated an attainment area for some pollutants and a nonattainment area for other pollutants. All counties in the state of North Dakota, including Oliver County, are currently in attainment with NAAQS (Reference (5)). As a result, the General Conformity Rule, which ensures that actions taken by federal agencies in nonattainment and maintenance areas are consistent with a state’s plans to meet NAAQS, does not apply to the Proposed Action. (The General Conformity Rule [CAA Section 176(c)] [42 U.S.C. 7506].)

North Dakota Administrative Code (NDAC) also sets ambient air quality standards, which are closely aligned with NAAQS (NDAC 33-15-02-04). In addition to the pollutants covered by NAAQS, North Dakota also sets standards for hydrogen sulfide ($H_2S$). Both NAAQS and North Dakota standards are summarized in Table 3-1.

**Table 3-1 National Ambient Air Quality Standards and North Dakota Administrative Code Ambient Air Quality Standards**

| Pollutant | Type | Averaging Time | Federal Standard | ND Standard | Form |
|---|---|---|---|---|---|
| CO | primary | 8-hour | 9 ppm | 9 ppm | Not to be exceeded more than once per year |
| CO | primary | 1-hour | 35 ppm | 35 ppm | Not to be exceeded more than once per year |
| Pb | primary and secondary | Rolling 3-month average | 0.15 $\mu g/m^3$ | 0.15 $\mu g/m^3$ | Not to be exceeded |
| $NO_2$ | Primary | 1-hour | 100 ppb | 100 ppb | $98^{th}$ percentile of 1-hour daily max. concentrations averaged over 3 years |
| $NO_2$ | primary and secondary | annual | 53 ppb | 53 ppb | Annual mean |
| $O_3$ | primary and secondary | 8-hour | 70 ppb | 70 ppb | Annual $4^{th}$-highest daily max. 8-hour concentration, averaged over 3 years |
| $PM_{2.5}$ | primary | annual | 12 $\mu/m^3$ | 12 $\mu/m^3$ | Annual mean, averaged over 3 years |
| $PM_{2.5}$ | secondary | annual | 15 $\mu/m^3$ | n/a | Annual mean, averaged over 3 years |
| $PM_{2.5}$ | primary and secondary | 24-hour | 35 $\mu/m^3$ | 35 $\mu/m^3$ | $98^{th}$ percentile, averaged over 3 years |
| $PM_{10}$ | primary and secondary | 24-hour | 150 $\mu/m^3$ | 150 $\mu/m^3$ | Not to be exceeded more than once per year on average over 3 years |
| $SO_2$ | primary | 1-hour | 75 ppb | 75 ppb | $99^{th}$ percentile of 1-hour daily maximum concentrations, averaged over 3 years |
| $SO_2$ | secondary | 3-hour | 500 ppb | 500 ppb | Not to be exceeded more than once per year |
| $H_2S$ | primary | instantaneous | None | 10 ppm | Not to be exceeded |
| $H_2S$ | primary | 1-hour | None | 0.2 ppm | Not to be exceeded more than once per month |
| $H_2S$ | primary | 24-hour | None | 0.2 ppm | Not to be exceeded more than once per year |
| $H_2S$ | primary | 3 months | None | 0.02 ppm | Maximum mean averaged over 3 months |

### 3.2.2 Ambient Air Quality and Monitoring

USEPA has delegated responsibility for many provisions of the CAA to the State of North Dakota, including demonstrating compliance with NAAQS. The North Dakota DEQ is responsible for monitoring the levels of criteria pollutants to demonstrate compliance with NAAQS in the state of North Dakota. DEQ – Division of Air Quality maintains and operates a network of ten Ambient Air Quality Monitoring (AAQM) sites. Nine of these sites are operated directly by DEQ and one additional site is operated in partnership with the National Park Service in the Theodore Roosevelt National Park South Unit at Painted Canyon. In addition, there are two monitors in Williams County that are operated by industry and overseen by DEQ. The closest ambient air monitor to the BNI Center Mine is the Hanover station, which is approximately 6 miles west of the mining area. The Hanover station provides continuous monitoring and is designated as a source impact site to monitor the impact of significant sources of criteria pollutants, including the Milton R. Young Station. Refer to Figure 3-1 for the relative locations of monitoring sites in relation to the BNI Center Mine.

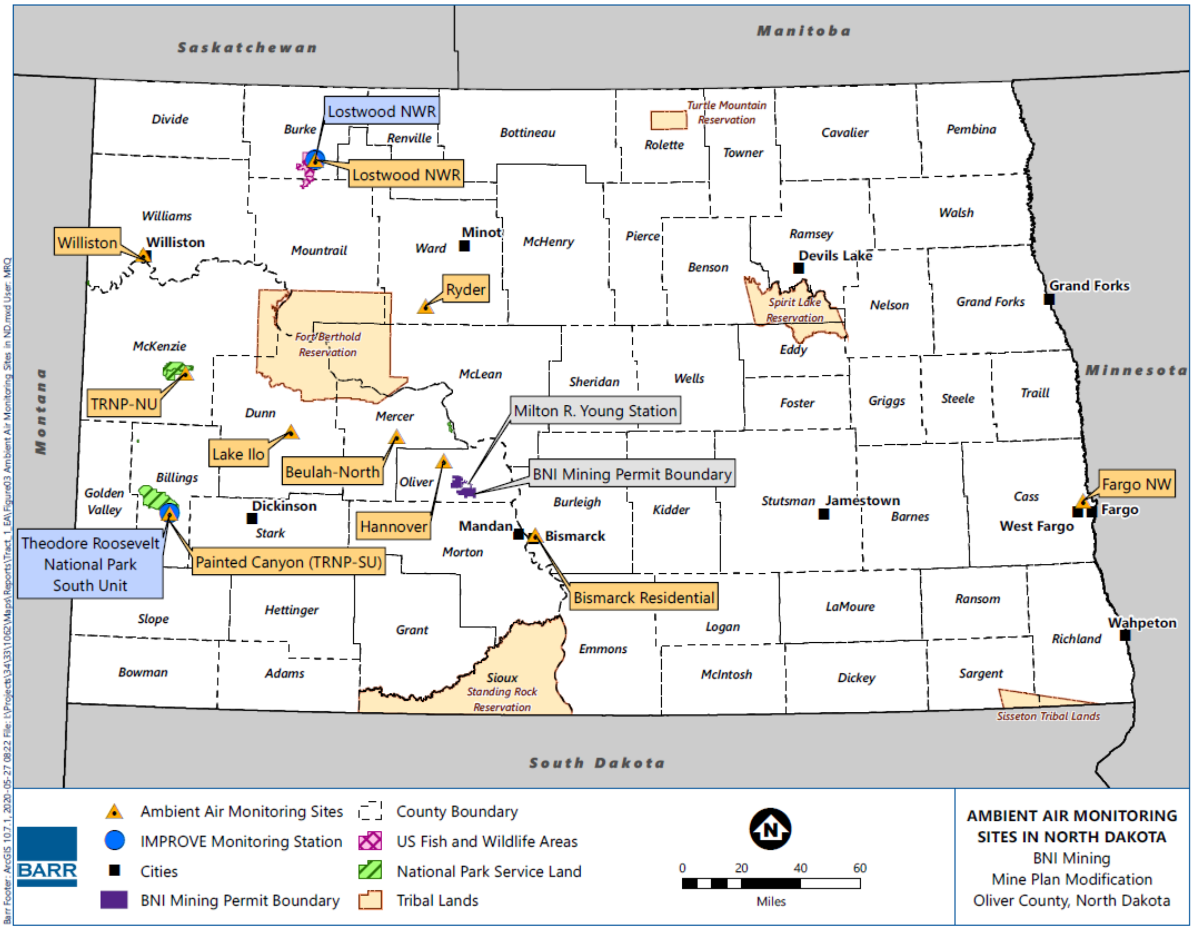



**Figure 3-1 Ambient Air Monitoring Sites in North Dakota**

Table 3-2 lists NAAQS and recorded levels of pollutants at the Hanover monitoring site as reported in the annual North Dakota AAQM Program Network Plan with Data Summary for the past five years (references (6), (7), (8), (9), (10)). Statewide monitoring for CO in ND has been suspended based on a five-year study concluded in 1994, which indicated ambient concentrations were far below NAAQS. Trace level monitoring at the Bismarck station is currently the only CO monitoring in ND with levels in 2018 of 0.82 ppm using a 1-hour averaging time and 0.4 ppm using an 8-hour averaging time, both of which are well below NAAQS values (reference (10)). Monitoring for Pb was suspended in 1984 in ND because DEQ has determined that the state has low ambient Pb concentrations and no significant sources of Pb (reference (10)). There is no statewide monitoring for $H_2S$ in ND because emissions are almost entirely associated with legacy sources (reference (10)). Note that DEQ annual reports do not include reporting for the 3-hour secondary $SO_2$ standard because the monitored concentrations are already well below the much more stringent 1-hour primary standard.

**Table 3-2 NAAQS Standard and Monitored Concentrations at Hanover**

| Pollutant | Type | Averaging Time | Federal Standard | Form | 2018 | 2017 | 2016 | 2015 | 2014 |
|---|---|---|---|---|---|---|---|---|---|
| CO | primary | 8-hour | 9 ppm | Not to be exceeded more than once per year | not reported | not reported | not reported | not reported | not reported |
| CO | primary | 1-hour | 35 ppm | Not to be exceeded more than once per year | not reported | not reported | not reported | not reported | not reported |
| Pb | primary and secondary | Rolling 3-month average | 0.15 µg/m$^3$ | Not to be exceeded | not reported | not reported | not reported | not reported | not reported |
| $NO_2$ | Primary | 1-hour | 100 ppb | 98$^{th}$ percentile of 1-hour daily max. concentrations averaged over 3 years | 14 ppb | 13 ppb | 14 ppb | 16 ppb | 16 ppb |
| $NO_2$ | primary and secondary | annual | 53 ppb | Annual mean | 2.24 ppb | 2.09 ppb | 2.09 ppb | 2.18 ppb | 2.17 ppb |
| $O_3$ | primary and secondary | 8-hour | 70 ppb | Annual 4$^{th}$-highest daily max. 8-hour concentration, averaged over 3 years | 59 ppb | 60 ppb | 59 ppb | 61 ppb | 59 ppb |
| $PM_{2.5}$ | primary | annual | 12 µ/m$^3$ | Annual mean, averaged over 3 years | 5.3 µ/m$^3$ | 4.9 µ/m$^3$ | 4.3 µ/m$^3$ | 4.9 µ/m$^3$ | 5.2 µ/m$^3$ |
| $PM_{2.5}$ | secondary | annual | 15 µ/m$^3$ | Annual mean, averaged over 3 years | 5.3 µ/m$^3$ | 4.9 µ/m$^3$ | 4.3 µ/m$^3$ | 4.9 µ/m$^3$ | 5.2 µ/m$^3$ |
| $PM_{2.5}$ | primary and secondary | 24-hour | 35 µ/m$^3$ | 98$^{th}$ percentile, averaged over 3 years | 16 µ/m$^3$ | 18 µ/m$^3$ | 18 µ/m$^3$ | 19 µ/m$^3$ | 16 µ/m$^3$ |
| $PM_{10}$ | primary and secondary | 24-hour | 150 µ/m$^3$ | Not to be exceeded more than once per year on average over 3 years | 65 µ/m$^3$ | 71 µ/m$^3$ | 72 µ/m$^3$ | 108 µ/m$^3$ | 80 µ/m$^3$ |
| $SO_2$ | primary | 1-hour | 75 ppb | 99$^{th}$ percentile of 1-hour daily maximum concentrations, averaged over 3 years | 12 ppb | 11 ppb | 10 ppb | 14 ppb | 24 ppb |
| $SO_2$ | secondary | 3-hour | 500 ppb | Not to be exceeded more than once per year | *not reported | *not reported | *not reported | *not reported | *not reported |

Source: Annual Reports – North Dakota AAQM – Network Plan with Data Summary (references (6), (7), (8), (9), (10))
* ND DEQ does not report the 3-hour averaging time monitoring data because the 1-hour averaging time values are well below the more stringent primary standard

### 3.2.3 Prevention of Significant Deterioration and Air Quality-Related Values

The Prevention of Significant Deterioration (PSD) permitting program applies to new major sources or major modifications to existing sources located in attainment areas to protect public health and welfare and to preserve and protect the air quality in national parks, national monuments, wilderness areas, and other areas of special interest. PSD rules also require assessment of air quality-related values (AQRV) defined as a resource “for one or more federal areas that may be adversely affected by a change in air quality. The resource may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by the federal land manager for a particular area.” (reference (11)) Neither the BNI Center Mine, nor the Proposed Action, are a major PSD source, which is defined as a source that emits over 250 tons per year of any criteria pollutant or over 100 tons per year for specifically listed source categories. Mobile and fugitive emissions are not included in PSD programs and are regulated through other permitting programs. As such, the assessment of AQRV is not required for impacts related to ongoing mining and proposed mining of federal coal at BNI Center Mine. However, to provide information and perspective on the Proposed Action and the indirect effect of coal combustion, the potential impacts from the nearby electricity generating Milton R. Young Station is considered in this EA. The Milton R. Young Station is a major source under the CAA and is, therefore, subject to stringent air emission limits and maximum available control technology (MACT) (reference (4)).

#### 3.2.3.1 Airsheds and monitoring

Under PSD regulations, air sheds are assigned a priority Class (I, II, or III) which describes how much degradation to the existing air quality is allowed to occur within the area. PSD Class I areas are areas of special national or regional natural, scenic, recreational, or historic value, and essentially allow very little degradation in air quality (i.e., National Parks, Wilderness Areas), while Class II areas allow for reasonable economic growth. Class III areas allow for substantial economic growth. BNI Center Mine and the federal lands in the Proposed Action are located in a Class II area. There are currently no Class III areas defined in North Dakota. Tribal lands in North Dakota are classified as sensitive Class II areas.

There are four Class I Areas located in North Dakota: TRNP – North Unit (McKenzie County), TRNP – Elkhorn Ranch Unit (Billings County), TRNP – South Unit (Billings County), and Lostwood National Wilderness Area (Burke County). Neither Tract 1 (NDM-102083), nor the Milton R. Young Station are located within a North Dakota Class I Area. All four Class I areas are generally upwind of both the Proposed Action and the Milton R. Young Station. It is, thus, unlikely the Proposed Action, or indirect impacts at the Milton R. Young Station would impact air quality or visibility conditions in North Dakota Class I areas.

There are three air monitoring stations in Class I areas in ND. TRNP – North Unit in McKenzie County has been designated as a general background, long range transport and welfare related monitor by DEQ and is approximately 97 miles to the west of the Proposed Action and104 miles west of the Milton R. Young Station. TRNP– South Unit in Billings County has been designated as a background monitor by DEQ and is approximately 96 miles to the west of the Proposed Action and 103 miles west of the Milton R. Young Station. LNWR in Burke County has been designated as a general background and significant source monitor and is approximately 116 miles north of the Proposed Action and122 miles north of the Milton R. Young Station. Refer to Figure 3-1 for the relative location of these site to the Proposed Action. Table 3-3 shows the recorded levels of pollutants at the designated long-range transport monitor and may be considered representative of air quality in Class I areas near the Proposed Action.

**Table 3-3 NAAQs Standard and Monitored Concentrations at TRNP- NU**

| Year | Station | Averaging Time | Federal Standard | Form | 2018 | 2017 | 2016 | 2015 | 2014 |
|---|---|---|---|---|---|---|---|---|---|
| CO | primary | 8-hour | 9 ppm | Not to be exceeded more than once per year | not reported | not reported | not reported | not reported | not reported |
| CO | primary | 1-hour | 35 ppm | Not to be exceeded more than once per year | not reported | not reported | not reported | not reported | not reported |
| Pb | primary and secondary | Rolling 3-month average | 0.15 µ/m³ | Not to be exceeded | not reported | not reported | not reported | not reported | not reported |
| $NO_2$ | Primary | 1-hour | 100 ppb | 98th percentile of 1-hour daily max. concentrations averaged over 3 years | 9 ppb | 10 ppb | 12 ppb | 12 ppb | 11 ppb |
| $NO_2$ | primary and secondary | annual | 53 ppb | Annual mean | 1.66 ppb | 1.30 ppb | 1.30 ppb | 1.66 ppb | 1.64 ppb |
| $O_3$ | primary and secondary | 8-hour | 75 ppb | Annual 4th-highest daily max. 8-hour concentration, averaged over 3 years | 58 ppb | 58 ppb | 57 ppb | 58 ppb | 57 ppb |
| $PM_{2.5}$ | primary | annual | 12 µ/m³ | Annual mean, averaged over 3 years | 4.2 µ/m³ | 3.7 µ/m³ | 2.8 µ/m³ | 3.4 µ/m³ | 4.6 µ/m³ |
| $PM_{2.5}$ | secondary | annual | 15 µ/m³ | Annual mean, averaged over 3 years | 4.2 µ/m³ | 3.7 µ/m³ | 2.8 µ/m³ | 3.4 µ/m³ | 4.6 µ/m³ |
| $PM_{2.5}$ | primary and secondary | 24-hour | 35 µ/m³ | 98th percentile, averaged over 3 years | 17 µ/m³ | 20 µ/m³ | 17 µ/m³ | 18 µ/m³ | 15 µ/m³ |
| $PM_{10}$ | primary and secondary | 24-hour | 150 µ/m³ | Not to be exceeded more than once per year on average over 3 years | 55 µ/m³ | 59 µ/m³ | 57 µ/m³ | 57 µ/m³ | 30 µ/m³ |
| $SO_2$ | primary | 1-hour | 75 ppb | 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years | 7 ppb | 7 ppb | 6 ppb | 6 ppb | 8 ppb |
| $SO_2$ | secondary | 3-hour | 50 ppb | Not to be exceeded more than once per year | *not reported | *not reported | *not reported | *not reported | *not reported |

* ND DEQ does not report the 3-hour averaging time monitoring data because the 1-hour averaging time values are well below the more stringent primary standard

#### 3.2.3.2 Visibility

In addition to regulating the degradation of air quality for NAAQS pollutants, the visibility in Class I areas, as an AQRV, must be monitored based on the Regional Haze Rule (RHR) CAA 169A and 169B, 40 C.F.R. 51, subpart P). Visibility impairment refers to the reduction in clarity of landscapes and scenic vistas from a distance resulting from human air pollution. The RHR requires states to coordinate with federal agencies and other interested parties to develop a state implementation plan (SIP) to reduce the pollution that causes visibility impairment and meet the national goal of no anthropogenic visibility impairment by 2064. Visibility reduction is caused by aerosols or small particles in the atmosphere which scatter and absorb light, thus, impacting visibility. Substances in the atmosphere associated with visibility impairment are ammonium sulfate aerosols, ammonium nitrate aerosols, organic carbon, and elemental carbon. Emissions of $NO_x$, $SO_2$, VOC and fine particulates ($PM_{2.5}$) may be contributors to the concentrations of these substances as precursors. Visibility impairment, or haze index, is measured in deciviews (dv), which is a measure of light extinction such that uniform dv changes in the haze index correspond to uniform incremental changes in visual perception. The deciview scale is zero for pristine conditions and increases as visibility degrades.

The primary anthropogenic sources of visibility impairment in North Dakota Class I Areas include electric utility steam generating units, including the Milton R. Young Station, energy production and processing sources, prescribed burning, and fugitive dust sources (reference (12)). Although the Milton R. Young Station emits pollutants, such as $SO_2$ and $NO_x$, associated with the formation of light scattering particles, the distance and location of the Milton R. Young Station downwind of Class I areas in North Dakota indicate it is unlikely continued emissions from the Milton R. Young Station will impact visibility in North Dakota Class I areas. Particulate emissions from surface coal mining are primarily fugitive emissions of large particles which do not travel far from the source. Additionally, best management fugitive dust control practices required by the state of North Dakota reduce particulate emissions from mine activities. As such, surface coal mining is not considered by North Dakota to be a major contributor to regional haze (reference (12)).

The Interagency Monitoring of Protected Visual Environments (IMPROVE) program tracks current visibility conditions and trends in national parks and wilderness areas. The two IMPROVE stations in North Dakota, which are co-located with DEQ monitoring network sites, characterize the regional haze level in North Dakota (Figure 3-1).

Average visual range in many Class I areas in the west is 60 to 90 miles (100 to 150 kilometers (km)), equivalent to 13.6 to 9.6 dv, or about one half to two thirds of the visual range that would exist without anthropogenic air pollution from stationary and mobile sources (64 Fed. Reg. 35714). Visibility conditions, within the context of the RHR, are described in terms of the haze index on the 20% worst visibility days (worst days) and 20% best visibility days (best days). The North Dakota SIP (reference (13)) identified natural visibility conditions and baseline (2000-2004 average) visibility conditions for TRNP and LNWA using IMPROVE data and RHR guidance. These conditions are summarized in Table 3-4.

**Table 3-4 Visibility conditions determined in ND SIP for TRNP and LNWA**

| Area | Condition | Best Days, dv | Worst Days, dv |
|---|---|---|---|
| TRNP | Natural conditions | 3.0 | 7.8 |
| TRNP | Baseline conditions (2000-2004) | 7.8 | 17.8 |
| TRNP | Current conditions in 2015 SIP Progress Report (2009-2013) | 6.4 | 16.9 |
| LNWA | Natural conditions | 2.9 | 8.0 |
| LNWA | Baseline conditions (2000-2004) | 7.9 | 20.2 |
| LNWA | Current conditions in 2015 SIP Progress Report (2009-2013) | 7.9 | 19.3 |

Sources: North Dakota SIP (reference (13)), and ND SIP Periodic Progress Report (Reference (12))

### 3.2.4 Emissions

Ambient air quality is influenced by local and upwind emissions including both natural sources (wildfires, biogenic) and anthropogenic sources including stationary point sources, area sources, and mobile sources. The National Emission Inventory (NEI) includes emissions data from anthropogenic sources and some natural sources, such as wildfires. The NEI for 2017 covers criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHG). Table 3-5 includes both anthropogenic sources and natural sources.

**Table 3-5 Summary of NEI 2017 Emissions Data for Oliver County, ND**

| Source | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | $NO_x$ | CO | TOC | Unit |
|---|---|---|---|---|---|---|---|
| Stationary sources | 3,535 | 919 | 3,615 | 10,068 | 248 | 261 | tons |
| Mobile sources | 853 | 108 | 0.5 | 286 | 735 | 112 | tons |
| Natural sources | 142 | 120 | 10.5 | 441 | 1,874 | 1,770 | tons |
| Total | 4,530 | 1,147 | 6,626 | 10795 | 2,857 | 2,143 | Tons |

Source: USEPA NEI (reference (14))

In general, anthropogenic sources may be categorized as stationary sources or mobile sources. Stationary sources, which include both stack or vent sources and fugitive sources, may be further classified as major or minor sources based on whether they emit a regulated air pollutant above the CAA threshold. Sources that do not emit any regulated pollutant in quantities above the CAA threshold may be classified as minor or area sources. The BNI Center Mine is considered a true minor source by DEQ. Criteria pollutant emissions from coal processing and combustion at the Milton R. Young Station are indirect emissions associated with the BNI Center Mine. For background, the indirect emissions associated with this electric generating facility are presented in Table 3-6. The Milton R. Young Station operates under Title V permit number T5-F76009, which includes 18 emission units: two cyclone-fired boilers, one auxiliary boiler, three engines, two crushers, seven silos, two rotary unloaders and one truck dump. The permit places emission limits for some pollutants on individual units as shown in Table 3-7. These limits are on an hourly basis, but a reasonable comparison to the annual actual emissions indicates that the source emits far below its permitted emissions. For example, if Milton R. Young operated Boiler 1 and Boiler 2 continuously its permit limits would theoretically allow for approximately 2,000 tons of $PM_{10}$, 57,500 tons of $SO_2$, and 26,500 tons of $NO_X$, all of which are far higher than actual emissions in the past five years. Emission limits, however, are not the only operational restriction at Milton R. Young. In addition to emission limits, the Title V permit requires the Milton R. Young Station to comply with mand CAA sections including sections of NSPS, MACT, PSD, and NESHAPs among others, resulting in additional requirements including opacity limits, pollution controls, monitoring, recordkeeping, testing, and reporting.

**Table 3-6 Annual Criteria Pollutant Emissions at Milton R. Young Station 2015-2019**

| Year | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | $NO_x$ | CO | TOC | $NH_3$ | Unit |
|---|---|---|---|---|---|---|---|---|
| 2015 | 338 | 36 | 2,735 | 9,008 | 146 | 148 | 12 | tons |
| 2016 | 252 | 28 | 2,638 | 8,140 | 9971 | 135 | 14 | tons |
| 2017 | 296 | 29 | 3,412 | 9,971 | 166 | 162 | 12 | tons |
| 2018 | 334 | 33 | 2,776 | 9,259 | 191 | 151 | 12 | tons |
| 2019 | 279 | 33 | 2,658 | 8,563 | 189 | 149 | 13 | tons |
| Average | 300 | 32 | 2,844 | 8,988 | 146 | 149 | 13 | Tons |

Source: Milton R. Young Air Emission Inventory Reports, DEQ (references (15), (16), (17), (18))

**Table 3-7 Permitted Emissions Units and Criteria Pollutant Limits at Milton R. Young Station**

| Emission Unit Description | Emission unit capacity | $PM_{10}$ limit, lbs/hour | $SO_2$ limit, lbs/hour | $NO_x$ limit, lbs/hour | CO limit, ppm |
|---|---|---|---|---|---|
| Boiler 1 | 3,200 MMBTU | 160.3 | 7,500 | 2,070 | -- |
| Boiler 2 | 6,300 | 315.1 | 5,635.2 | 3,995.6 | -- |
| Auxiliary Boiler | 78 | -- | 234* | -- | -- |
| Unit 1 crusher | n/a | 4.3 | -- | -- | -- |
| Unit 2 crusher | n/a | 82 | -- | -- | -- |
| Unit 1 coal silos | n/a | 7.5 | -- | -- | -- |
| Unit 2 coal silos | n/a | 18.5 | -- | -- | -- |
| Unit 1 fly ash rotary unloader | n/a | -- | -- | -- | -- |
| Unit 2 flu ash rotary unloader | n/a | -- | -- | -- | -- |
| Unit 1 fly ash silo | n/a | 2.2 | -- | -- | -- |
| Unit 2 fly ash silo | n/a | 2.2 | -- | -- | -- |
| Unit 1 lime silo | n/a | -- | -- | -- | -- |
| Unit 2 lime silo | n/a | -- | -- | -- | -- |
| Unit 2 truck dump | n/a | -- | -- | -- | -- |
| Water treatment lime silo | n/a | -- | -- | -- | -- |
| Caterpillar engine | 237 bhp | -- | -- | -- | 230 |
| Cummins engine | 190 bhp | -- | -- | -- | 230 |
| Cummins engine | 2,205 bhp | -- | -- | -- | -- |

*pound per hour limit extrapolated from 3.0 lb/MMBTU limit and nameplate capacity

### 3.2.5 Hazardous Air Pollutants

In addition to criteria pollutants, USEPA regulates a list of HAPs under Section 112 of the CAA known as the National Emission Standards for Hazardous Air Pollutants (NESHAPs). HAPs are pollutants that cause, or may cause, cancer, serious health effects, or adverse environmental and ecological effects. The CAA Amendments of 1990 lists 187 HAPs, including pollutants such as asbestos, benzene, chlorine, and mercury compounds. Most air toxics are generated from mobile or stationary, anthropogenic sources. Major stationary sources for HAPs are sources that emit 10 tons per year of any single listed HAP or 25 tons per year of all HAPs combined. Major HAPs sources are subject to MACT, which are specific to the industrial source category. Area sources are defined as smaller facilities that release less than 10 tons per year of any listed HAP and less than 25 tons per year of total HAPs (reference (19)). The BNI Center Mine emits less than 10 TPY of any listed HAP and less than 25 TPY of all HAPs combined and is not subject to MACT standards. As described in Section 2.1.1,the implementation of the Proposed Action would not change the production levels, annual emissions, or extend the life of mine at BNI Center Mine. HAP emissions are also generated indirectly from the combustion of coal. The HAPs emissions from the Milton R. Young Station, which combusts BNI Center Mine coal, are available in the NEI and the Milton R. Young Station reports acid HAP emissions annually to the state of North Dakota. These emissions are summarized in Table 3-8. The Milton R. Young Station is a major source for HAPs and has an HCl emission limit of 0.2 lb/MMBTU for both Boiler 1 and Boiler 2. Milton R. Young is subject to the MACT standards for stationary reciprocating internal combustion engines (40 C.F.R. Part 63 ZZZZ), major source boilers (40 C.F.R. Part 63 DDDDD), and coal and oil-fired electric utility steam generating units (40 C.F.R. Part 63 UUUUU).

**Table 3-8 Annual HAPs Emissions at Milton R. Young Station 2015-2019**

| Year | Total Metal HAPs[1] | Total HAPs and VOCs[1] | HCl[2] | HF[2] | Unit |
|---|---|---|---|---|---|
| 2015 | N-D | N-D | 42,200 | 42,200 | Pounds |
| 2016 | N-D | N-D | 38,440 | 38,440 | Pounds |
| 2017 | 2,465 | 38.8 | 46,400 | 46,400 | Pounds |
| 2018 | N-D | N-D | 43,000 | 43,000 | Pounds |
| 2019 | N-D | N-D | 42,543 | 42,543 | Pounds |
| **Average** | **2,465** | **38.8** | **42,517** | **42,517** | **Pounds** |

Notes:

(1) Data from the 2017 NEI (reference (20)), the most recent dataset. NEI data available for 2015, 2016, 2018, 2019 as it is only published every three years.

(2) Milton R. Young Air Emission Inventory Reports, DEQ (reference (14)). 2019 emissions are calculated based on 2019 coal throughput at Milton R. Young Station.

N-D = no data

### 3.2.6 Mercury

Mercury is a naturally occurring element (21) that is present throughout the environment in both environmental media and biota (reference (20)) and is considered a global pollutant (reference (22)). It can act as a powerful neurotoxin affecting the nervous system that can cause cerebral palsy, deafness, blindness and other serious health effects in humans and animals. When inorganic mercury enters an aquatic ecosystem, under certain conditions, it can undergo a process known as methylation resulting in methylmercury (MeHg) (reference (20)). Biomagnifying up through the food chain, MeHg ultimately leads to elevated concentrations in the tissue of top predator fish exposing the general public when the fish are consumed. Methylmercury is a potent toxin because of its high solubility in fatty tissue in animals, resulting in significant potential for bioaccumulation and biomagnification. As a result, MeHg is considered the most hazardous form of mercury.

Fish consumption is the most significant exposure pathway for people. The potential for the Proposed Action to increase local mercury deposition and increase MeHg concentrations in fish that are then consumed by recreational fishers is assessed in this EA.

Mercury is also a listed HAP. Mercury emissions are from both natural sources and anthropogenic sources as well as re-emission of mercury from the global mercury pool. Globally, anthropogenic sources account for about 30% of the total mercury entering the atmosphere annually (reference (23)). Coal combustion is a major source of anthropogenic mercury emissions world-wide (reference (23)) and coal combustion at power plants is the primary sector associated with mercury emissions in North Dakota (reference (24)). The Milton R. Young Station, which combusts coal from the BNI Center Mine, is the closest power plant to the location of the Proposed Action. Power plants within North Dakota report emissions to the NDDH via Annual Emission Inventory Reports. Mercury emissions for the past five years from the Milton R. Young Station is summarized in Table 3-9. Milton R. Young has a mercury emission limit of 0.004 lbs/MMBTU for both Boiler 1 and Boiler two. Applicable MACT standards described in Section 3.2.5 restrict emissions of HAP pollutants such as mercury.

**Table 3-9 Annual Mercury Emissions at Milton R. Young Station 2015-2019**

| Emissions | 2015 | 2016 | 2017 | 2018 | 2019 | Unit |
|---|---|---|---|---|---|---|
| Mercury | 179 | 156 | 201 | 180 | 174 | Pounds |

Source: Milton R. Young Air Emission Inventory Reports provided by BNI

#### 3.2.6.1 Background Environment

Nelson Lake is the only named water body within 10 km of the Milton R. Young Station. This man-made reservoir was created in 1968 with a 45-foot high, earth-filled dam across Square Butte Creek. The lake is 2.5-miles long, and approximately 600 acres in size (surface area estimates range from 573 acres to 660 acres in size). It is approximately 35 feet (ft) deep at its deepest point.

The Milton R. Young Station is immediately adjacent to Nelson Lake. The lake provides water for cooling, boiler makeup and other station uses in the power production process. All water used in plant processes is tested and treated to confirm that its quality meets all standards for discharge (reference (25)). The lake is also a popular spot with fishing and outdoor enthusiasts.

According to the North Dakota Game and Fish Department, Nelson Lake is the best largemouth bass lake in the state (reference (26)). Open water year-round allows warm-water fish to grow better than in other lakes. There is also abundant quality-sized bluegill and crappie. The lake also has many sunfish, bullheads, northern pike and perch (reference (25)).

Available data from the National Atmospheric Deposition Program (NADP; http://nadp.slh.wisc.edu/MDN/annualmdnmaps.aspx) indicates that North Dakota receives some of the lowest mercury deposition in the continental U.S. The most recent estimates of mercury deposition in North Dakota are for 2017 and 2018; approximately 3.7 and 7 micrograms per square meter per year (µg/m$^2$/yr), respectively, with an average for the two years being 5.3 µg/m$^2$/yr (reference (27)). As identified by the NADP, mercury deposition increases from west to east with average mercury deposition being approximately 7.7 µg/m$^2$/yr in north-central Minnesota (2017-2018), and from north to south with average mercury deposition being approximately 6.9 µg/m$^2$/yr in central South Dakota (2016-2017)

Available information from the State of North Dakota identifies that Nelson Lake currently has a general fish consumption advisory for panfish, northern pike, and bass based on fish size.

- For panfish (crappies and sunfish), meal limitations for women of child-bearing age range from 1 meal per month for larger fish (>9 to 11 inches) to 8 meals per month for smaller fish (<9 inches in size) (reference (28)).
- For northern pike, meal limitations for women who are or could become pregnant, or breast-feeding mothers, range from 1 meal per month for larger fish (>28 inches) to 4 meals per month for smaller fish (<25 inches) (reference (29)).
- For largemouth bass, North Dakota (reference (30)) identifies for pregnant and nursing women that fish more than 16 inches in length should not be consumed, with 1 to 4 meals per month allowed for smaller size fish.

### 3.2.7 Greenhouse Gas/Climate Change

Greenhouse gases (GHG) permit incoming (short-wave) radiation from the sun to enter the earth’s atmosphere, but block infrared (long-wave) radiation from leaving the earth's atmosphere. Through complex interactions on a global scale, the emissions of GHG, along with other climate-influencing environmental factors, cause a net warming of the atmosphere. GHG include carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), water vapor, $O_3$, fluorocarbons, and sulfurhexafluoride gas. These are called GHG because when released into the atmosphere they impede the escape of reflected solar radiation and heat from the Earth’s surface back into space. In this way, the accumulation of GHG in the atmosphere exerts a “greenhouse effect” on the earth’s temperature.

GHG emissions can be anthropogenic (human-made) or naturally occurring (e.g., volcanic activity). Other than GHG emissions, factors that contribute to global warming include aerosols, changes in land use, and variations in cloud cover and solar radiation which affect the absorption, scattering, and emissions of radiation within the atmosphere and at the Earth's surface. As GHG concentrations increase in the atmosphere, they impact the global climate by further decreasing the amount of heat that is allowed to escape back into space. The average global temperature increased 1.8°F during the period from 1901 to 2016 and 1.2°F during the period from 1986 to 2015; almost the entire planet experienced higher surface temperatures and average global temperatures could rise by as much as 9°F by the end of the century (reference (29)). Because temperature is a part of climate, the phenomenon of global warming is both an element of and a driving force behind climate change (reference (31)).

The term "climate change" refers to a substantial and persistent change in the mean state of global or regional climate or its variability, usually occurring over decades or longer (reference (32)). In 2014, the Intergovernmental Panel on Climate Change produced the Climate Change Synthesis Report and Summary for Policymakers. The US Global Change Research Program published its fourth national climate assessment in 2018. Each of these reports state that anthropogenic (i.e., human- caused) GHG emissions have increased since the preindustrial era, driven largely by economic and population growth, and are now higher than they have ever been previously recorded. This has led to atmospheric concentrations of $CO_2$, $CH_4$, and $N_2O$ that are unprecedented in at least the last 800,000 years. These anthropogenic GHG emissions are "extremely likely" to have been the dominant cause of the observed warming since the mid-20th century (references (29), (31)).

These climatic changes are impacts in and of themselves; however, they can also affect other aspects of the environment including desert distribution, sea level, precipitation changes, frequency of severe storms, species distribution, species survivability, ocean salinity, availability of fresh water, and disease vectors. These effects can vary from region to region over time; some agricultural regions may become more arid while others become wetter; some mountainous areas may experience greater summer precipitation, yet have their snowpack disappear in the future (reference (31)).

The current climate in North Dakota is characterized by large temperature variations, both seasonally and daily which are associated with the movement of air masses across its location in the geographic center of the continent. Statewide, there are 40-70 days with temperatures below 0°F and 10-24 days with temperatures above 90°F. Nearly continuous winds contribute to temperature fluctuations and a high degree of evapotranspiration. Precipitation is irregular with averages of 14-22 inches annually, occurring mostly during the growing season (reference (33)).

Climate model predictions for the Northern Great Plains indicate rising temperatures with the number of days of both extreme heat and extreme cold increasing through the mid-21st century. Overall precipitation projections show modest change in overall quantity, but with reduced snowpack and a mix of increase and decreases in water availability with more extreme flood events during summer months (reference (34)). Warmer temperatures lengthen the growing season, which could increase plant growth or allow for a second planting. However, the variability in summer precipitation increases vulnerability to drought conditions and higher summer temperatures are likely to reduce plant productivity. Climate change is also increasing pest outbreaks, spreading invasive species, accelerating wildfire activity, and changing plant flowering times (reference (34)). Thus, the causes and effects of climate change, while variable, can be described as follows. First, GHG are emitted and other events occur which contribute to climate change in the form of global warming. Second, climate change contributes to environmental effects around the globe.

### 3.2.7.1 Greenhouse Gas Emissions

Factors that determine a GHG effect on climate change include its concentration, duration, and Global Warming Potential (GWP). The GWP is determined by the length of time a GHG remains in the atmosphere and the strength with which it absorbs energy. In order to aggregate GHG emissions, total GHG emissions are characterized in terms of $CO_2$ equivalent ($CO_2e$) by adding the product of each GHG multiplied by its GWP. $CO_2$ has a GWP of 1, while $CH_4$ and $N_2O$ have GWPs of 25 and 298, respectively, based on 100- year GWPs (40 C.F.R. Part 98, Table A-1). For any quantity and type of GHG, $CO_2e$ represents the amount of $CO_2$ that would have the equivalent global warming impact. The GHG directly emitted from the mining of coal are from diesel and gasoline-powered vehicles. Indirectly, GHG are also produced from the generation of electricity used on the mine site and from transporting the coal to the end user once it is mined.

USEPA regulates GHG emissions under several initiatives, including the Mandatory Greenhouse Gas Reporting rule, the Final Greenhouse Gas Tailoring rule, geologic sequestration requirements, and USEPA and National Highway Traffic Safety Administration standards for new motor vehicles. USEPA's Mandatory Greenhouse Gas Reporting rule requires industrial facilities and suppliers of fossil fuels or industrial gases that result in greater than 25,000 MT of $CO_2e$ of GHG emissions per year to report their emissions. Under the Mandatory Greenhouse Gas Reporting rule (40 C.F.R. 98), coal mines subject to the rule are required to report emissions in accordance with the requirements of Subpart FF. Subpart FF is applicable only to underground coal mines and would not apply to the Proposed Action. Because no change to annual emissions at the Mine would occur under the Proposed Action, no other GHG reporting or permitting requirements would apply.

According to USEPA (reference (35)), in 2017 (the most recent year of available $CO_2$ data at this time), $CO_2e$ emissions in the United States totaled 6,456.7 million metric tons (MMT). The estimated $CO_2e$ contribution of U.S. emissions would be approximately 12% of the total global $CO_2e$ emissions of 53,500 MMT in 2017 (reference (36)). In 2018, the U.S. Geological Survey (USGS) published a report titled *Federal Lands Greenhouse Gas Emissions and Sequestration in the United States: Estimates for 2005–14* (reference (37)) on GHG emissions from extraction and use of fossil fuels produced on federal lands and GHG sinks (carbon storage by terrestrial ecosystems) on federal lands in the United States. In 2014, nationwide emissions from fossil fuels (oil, gas, and coal) extracted from federal lands were 1,279.0 MMT $CO_2e$ of $CO_2$, 47.6 MMT $CO_2e$ of $CH_4$, and 5.5 MMT $CO_2e$ of $N_2O$ based on 100-year GWPs (reference (37)). In 2014, carbon storage by terrestrial ecosystems on federal lands in the conterminous United States (not including Alaska and Hawaii) was 83,600 MMT $CO_2e$. Soils stored 63 percent of carbon, with vegetation and dead organic matter storing 26 percent and 11 percent, respectively (reference (37)). Between 2005 and 2014, the annual rate of net carbon uptake by terrestrial ecosystems in the conterminous United States ranged from a sink (sequestration) of 475 MMT $CO_2$e per year to a source (emission) of 51 MMT $CO_2$e per year due to changes in climate/weather, land use, land cover change, wildfire frequency, and other factors. Terrestrial ecosystems on federal lands sequestered an average of 195 MMT $CO_2$e per year nationally between 2005 and 2014 (reference (37)).

USEPA collects GHG emissions data in the US by source sector (e.g., industrial, land use, electricity generation), fuel source (e.g., natural gas, coal, geothermal), and economic sector (e.g., industrial, commercial, residential). Considering the diverse sources of GHG emissions nationally, from cattle to vehicles to electric power generation, no single source is likely to represent a significant percentage of national emissions. Total GHG emissions for the U.S. are presented in Table 3-10 for selected source sectors. GHG from coal mining are included in Industry emissions and were estimated to be 52.7 MMT $CO_2$e in 2018, or approximately 1% of the total US GHG Inventory. According to the U.S. Energy Information Administration (reference (38)), US coal production in 2018 was 756,167,000 short tons of which 29,643,000 short tons (approximately 4%) were produced from five surface coal mines in North Dakota. Assuming roughly proportional emissions across coal mining operations, the five surface mines in North Dakota account for roughly 0.03% of the US GHG inventory. Power production accounts for approximately one third of the US GHG inventory and the Milton R. Young Station that burns BNI Center Mine coal accounts for approximately 0.4% of the electric power industry 2018 GHG emissions and approximately 0.1% of the 2018 US GHG inventory.

**Table 3-10 1990-2018 Estimated US Greenhouse Gas Emissions Allocated to Economic Sectors (in MMT of CO2e)**

| Sector | 1990 | 2005 | 2015 | 2018 |
|---|---|---|---|---|
| Electric Power Industry | 1,876 | 2,456 | 1,949 | 1,799 |
| Transportation | 1,527 | 1,973 | 1,800 | 1,860 |
| Industry | 1,629 | 1,500 | 1,427 | 1,484 |
| Agriculture | 599 | 628 | 656 | 659 |
| Commercial | 429 | 405 | 423 | 455 |
| Residential | 345 | 370 | 352 | 375 |
| US Territories | 33 | 58 | 46 | 46 |
| Total Emissions | 6,437 | 7,390 | 6,674 | 6,678 |
| Land Use, Land-Use Change, and Forestry (Sink) | (853) | (815) | (776) | (774) |
| **Net Emissions (Sources and Sinks)** | **5,584** | **6,575** | **5,898** | **5,904** |

Source: Table 2-10 of reference (39)

Note that “Land Use, Land-Use Change, and Forestry” represents a sink rather than a source and is therefore presented in parentheses.

Emissions at the state level is available from USEPA’s Facility Level Information on Greenhouse Gasses Tool (FLIGHT) for facilities that are required to report GHG emissions under USEPA’s mandatory GHG Reporting rule. Table 3-11 summarizes the emissions reported in North Dakota from 2011 to 2018. This data shows some variability between years, but approximately an increase of 10% in overall emissions since 2011 (reference (40)).

**Table 3-11 Greenhouse Gas Emissions in the State of North Dakota (in MMT CO2e)**

| Sector | 2011 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| Electric Power Industry | 30 | 31.2 | 30.1 | 30 | 31 |
| Petroleum and natural gas | 1.6 | 2.0 | 2.1 | 2.4 | 2.4 |
| Refineries | 0.6 | 0.8 | 0.8 | 0.7 | 0.8 |
| Chemicals | 3 | 2.9 | 3.3 | 3.2 | 4.1 |
| Minerals | 0.9 | 1 | 1 | 1 | 1.1 |
| Waste | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 |
| Other | 0.7 | 0.6 | 0.7 | 0.7 | 0.7 |
| **Total Emissions** | **37.2** | **39.1** | **38.5** | **38** | **41** |

Source: USEPA Facility Level Information on Greenhouse Gasses Tool (FLIGHT)

Coal from BNI Center Mine is combusted at the Milton R. Young Station. The indirect emissions generated at this facility are summarized in Table 3-12. The GHG emissions from combustion of BNI Center Mine coal have been consistent in the 2015-2019 time period.

**Table 3-12 Annual Greenhouse Gas Emissions at Milton R. Young Station 2015-2019**

| Year | Coal Combusted | $CO_2$ | $CH_4$ | $N_2O$ | $CO_2e$ | Unit |
|---|---|---|---|---|---|---|
| 2015 | 4,319,590 | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |
| 2016 | 4,319,590 | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |
| 2017 | 4,319,590 | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |
| 2018 | 4,342,650 | 6,030,209 | 679 | 99 | 6,075,380 | metric tons |
| 2019 | 4,296,530 | 5,966,167 | 672 | 98 | 6,010,858 | metric tons |
| Average | 4,319,590 | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |

Source: Emissions calculated from reported coal use and emission factors in Table C-1 and C-2 to Subpart C of 40 C.F.R. Part 98 (reference (41)).

### 3.2.7.2 Social Cost of Carbon

A protocol to estimate what is referenced as the *social cost of carbon* (SCC) associated with GHG emissions was developed by a federal interagency working group to assist federal agencies in addressing EO 12866, Regulatory Planning and Review, that requires the assessment of the cost and the benefits of proposed regulations as part of their regulatory impact analyses. On March 28, 2017, President Donald Trump issued EO 13783, which, among other actions, withdrew the technical support documents upon which the protocol was based and disbanded the earlier Interagency Working Group on the Social Cost of GHG. The EO further directed agencies to ensure that estimates of the social cost of GHG used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in the U.S. Office of Management and Budget (OMB) Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (EO 13783, Section 5(c)). In compliance with OMB Circular A-4, interim protocols have been developed for use in the rulemaking context; however, OMB Circular A-4 does not apply to project decisions, so there is no EO requirement to apply the SCC protocol to project decisions.

The SCC is an estimate of the economic damages associated with an increase in $CO_2$ emissions and is intended to be used as part of a cost-benefit analysis for proposed rules. As explained in the Executive Summary of the 2010 SCC Technical Support Document, "the purpose of the [SCC] estimates . . . is to allow agencies to incorporate the social benefits of reducing $CO_2$ emissions into cost-benefit analyses of regulatory actions that have small, or 'marginal,' impacts on cumulative global emissions" (Interagency Working Group on the Social Cost of Carbon 2010). While the SCC protocol was created to meet the requirements for regulatory impact analyses during rulemakings, there have been requests by public commenters or project applicants to expand the use of SCC estimates to project-level NEPA analyses.

The decision was made not to expand the use of the SCC protocol for the federal coal tracts for a number of reasons. Most notably, this action is not a rulemaking for which the SCC protocol was originally developed.

Further, NEPA does not require a cost-benefit analysis (40 C.F.R. 1502.23), although it does require consideration of "effects" that include "economic" and "social" effects (40 C.F.R. 1508.8(b)). Without a complete monetary cost-benefit analysis, which would include the social benefits of the Proposed Action to society as a whole and other potential positive benefits, sole inclusion of an SCC cost analysis would be unbalanced, potentially inaccurate, and not useful in facilitating an authorized officer's decision. Any increased economic activity, in terms of revenue, employment, labor income, total value added, and output, that is expected to occur with the Proposed Action is simply an economic impact rather than an economic benefit, in as much as such impacts might be viewed by another person as negative or undesirable due to potential increases in local population, competition for jobs, and concerns that changes in population would change the quality of the local community. Economic impact is distinct from economic benefit as defined in economic theory and methodology, and the socioeconomic impact analysis required under NEPA is distinct from cost-benefit analysis, which is not required.

Finally, the SCC protocol does not measure the actual incremental impacts of a project on the environment and does not include all damages or benefits from carbon emissions. The SCC protocol estimates economic damages associated with an increase in $CO_2$ emissions—typically expressed as a 1 MT increase in a single year—and includes, but is not limited to, potential changes in net agricultural productivity, human health, and property damages from increased flood risk over hundreds of years. The estimate is developed by aggregating results "across models, over time, across regions and impact categories, and across 150,000 scenarios" (reference (42)). The dollar cost figure arrived at based on the SCC calculation represents the value of damages avoided if, ultimately, there is no increase in carbon emissions. But the dollar cost figure is generated in a range and provides little benefit in assisting the authorized officer's decision for project-level analyses because it is too uncertain. For example, in a previous EIS, OSMRE estimated that the selected alternative had a cumulative SCC ranging from approximately $4.2 billion to $22.1 billion depending on dollar value and the discount rate used and the cumulative SCC for the No Action Alternative ranged from $2.0 billion to $10.7 billion.

Given the uncertainties associated with assigning a specific and accurate SCC resulting from a total of 5 additional months of operation under the mining plan modification, and that the SCC protocol and similar models were developed to estimate impacts of regulations over long time frames, OSMRE's ability to evaluate these impacts on a project-level would be doubtful without a complete monetary cost-benefit analysis, which would include the social benefits of the Proposed Action to society as a whole and other potential positive benefits, inclusion solely of an SCC cost analysis would be unbalanced, potentially inaccurate, and not useful in facilitating an authorized officer's decision. This conclusion is supported in the February 2018 BLM Regulatory Impact Analysis for the Proposed Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule (reference (43)), noting that "[t]he scientific and economics literature has further explored known sources of uncertainty related to estimates of the social cost of carbon and other greenhouse gases noting further that researchers have examined the sensitivity of IAMs and the resulting estimates to different assumptions embedded in the models (e.g., Pindyck 2013; Hope 2013; Anthoff and Tol 2013; Nordhaus 2014; Waldhoff et al. 2014)." The BLM further spoke to the "additional sources of uncertainty that have not been fully characterized and explored due to remaining data limitations", concluding that "[a]dditional research is needed to expand the quantification of various sources of uncertainty in estimates of the social cost of carbon and other greenhouse gases (e.g., developing explicit probability distributions for more inputs pertaining to climate impacts and their valuation)." The BLM further states, "[o]n damage functions, other experts have found that those used in most IAMs have no theoretical or empirical foundation, claiming that the overall model is able to 'obtain almost any result one desires' (Pindyck 2013). Naturally, the indeterminate amount of uncertainty surrounding the IAMs used to approximate social costs for specific greenhouse gas emissions merits additional research and analysis and further peer-review in order to better ascertain the best available science and economics in accordance with E.O. 13783." The BLM's discussion is in the context of a rulemaking for which the SCC was developed. The uncertainties regarding the applicability of the SCC by OSMRE in the context of a specific project is even greater.

To summarize, this EA does not undertake an analysis of SCC because 1) it is not engaged in a rulemaking for which the protocol was originally developed; 2) NEPA does not require cost-benefit analysis and one has not been conducted here; and 3) the full social benefits of coal-fired energy production have not been monetized, and quantifying only the costs of GHG emissions, but not the benefits, would yield information that is both potentially inaccurate and not useful. On a global scale, the GHG emission contribution of any single geographic subunit (such as a SMCRA-delegated state regulatory authority or OSMRE regional office) or source (such as federal minerals) on a subnational scale is dwarfed by the large number of comparable national and subnational contributors. The relative contribution of GHG emissions from production and consumption of federal minerals will vary depending on contemporaneous changes in other sources of GHG emissions. A single subnational contributor is very unlikely to influence global cumulative emissions. Refer to Section 5.2.1.2 for more details.

### 3.2.8 Metals

The potential exists for particulate metal emissions generated from coal combustion to deposit locally and to affect potential occurrences of federally listed threatened and endangered species within a 3 km radius of the Milton R. Young Station. The extent of the assessment area is based on studies evaluating inputs of trace metals to the local environment surrounding coal burning power plants. One such study by Evans at al. (reference (44)) used a deposition model that predicted that emitted ash (particulate) fell within a few km of the source. Soil sampling results identified that after 23 years of operations, concentrations at 1.8 km from the source reflected particulate inputs from the power plant while soil concentrations from 2.5 km out to 16 km (maximum distance evaluated) reflected rural background conditions. The authors concluded that enrichment of metals, including mercury, from the power plant's emissions would not be detectable at distances greater than 2.5 km (reference (44)). Similarly, Cannon and Swanson (reference (45)) found that concentrations of trace metals in soils that originate from a power plant with emissions from tall stacks (~300+ ft; 90+ m), with operations starting in 1963, decrease rapidly with distance from the stacks. Soil concentrations within 3 km of the power plant indicate enrichment from atmospheric deposition, while at distances greater than 3 km, all metal concentrations are lower than the average concentrations of US soils (reference (46)).

Another factor that limits the local deposition of particulate metals is a power plant's stack height. In the Evans et al. (reference (44)) study, nearly half of the modeled particulate emissions deposited within 5 km of the source because of a relatively short stack height (38 meters [m]; approximately 125 ft). As previously discussed, detectable increases in soil metal concentrations were only predicted to occur within 3 km of the source (and largely confirmed by soil sampling results). The study also included measurements of aerial deposition at 5.5 km from the source and deposition was similar to rural background, with the authors concluding that soil metal concentrations at 5.5 km from the power plant reflected rural background conditions and were not associated with particulate emissions from that source (reference (44)). Stack height therefore plays a role in how high up in the atmosphere pollutants can be emitted and how far they are able to travel before being deposited. The Milton R. Station's stack height is approximately 170 m (557 ft) allowing for emissions to be emitted higher up in the atmosphere and providing good dispersion of the emissions from the stack source. With better dispersion, air pollutants travel further from the source, but the air concentration of a pollutant generally decreases due to better mixing in the atmosphere. A smaller air concentration results in less deposition. This means that while pollutants may disperse further from taller stacks, they do not deposit in detectable concentrations at distance from the facility, as found by Evans et al. (reference (44)) and Cannon and Swanson (reference (45)).

It is noted that many coal-fired power plant studies were conducted in the 1970's when emission rates were higher due to fewer pollution controls (reference (47)). Any local deposition of pollutants from a coal-fired power plant that has implemented modern pollution controls, such as the Milton R. Young Station, would be greatly reduced.

Guidance indicates that an action area or assessment area for a Proposed Action's effect on endangered species include the spatial extent of the impacts of the proposed action to modify the physical, biological, and chemical components of land, water, or air (reference (48)). Based on the findings from Evans et al. (reference (44)) and Cannon and Swanson (reference (45)), for this EA the assessment area for potential mercury and particulate metal deposition and potential effect on threatened and endangered species or other biological receptors is therefore confined to a 3 km radius around the Milton R. Young Station.

#### 3.2.8.1 Threatened and Endangered Species

Federally listed threatened and endangered species that have the potential to occur in the vicinity of the Milton R. Young Station include:

- Dakota Skipper,
- Northern Long-Eared Bat,
- Least Tern,
- Piping Plover,
- Whooping Crane,
- Red Knot, and
- Pallid Sturgeon.

Protected species that have the potential to occur in the vicinity of the Milton R. Young Station include:

- Bald Eagle

A brief description of each species and their habitat is provided in Table 3-13.

**Table 3-13 Federal-listed Threatened and Endangered Species and Protected Species Descriptions and Habitat**

| Species | Habitat Description and Habitat |
|---|---|
| Dakota Skipper | Small butterfly that lives in high quality mixed and tall grass prairie with high diversity of wildflowers and grasses (reference (49)). |
| Northern Long-eared bat | Medium-sized bat native to North America with a range spanning eastern and north central United States and all Canadian provinces. Northern long-eared bats hibernate in caves and mines, swarming in surrounding wooded areas in the fall. During spring and summer, the species roosts and forages in upland forests (reference (50)). |
| Least Tern | This species was initially identified as potentially present in the assessment area. However, after further review it has been concluded this species does not have the potential to be present in the assessment area. The shoreline of Lake Nelson is not suitable for the least tern. |
| Piping Plover | This species was initially identified as potentially present in the assessment area. However, after further review it has been concluded this species does not have the potential to be present in the assessment area. The shoreline of Lake Nelson is not suitable for the piping plover. |
| Whooping Crane | The whooping crane’s preferred habitat is freshwater and saltwater marshes and wetlands. They may be spotted in North Dakota during their spring migration from their wintering grounds at Aransas National Wildlife Refuge in Texas to their nesting grounds at Wood Buffalo National Park in Canada (reference (51)). |
| Red Knot | Red Knots are typically found on beaches and sandbars or alkaline wetlands. In North Dakota, they can be found in freshwater lakes during migration. There are no stopover sites consistently used by this bird species in North Dakota (reference (52)). |

| | |
|---|---|
| Pallid Sturgeon | This species was initially identified as potentially present in the assessment area. However, after further review it has been concluded this species does not have the potential to be in the assessment area and is not listed as a fish species present in Nelson Lake. |
| Bald Eagle | Bald eagles were removed from the endangered species list in 2007 but are protected under the Migratory Bird Treaty Act and the Bald and Golden Eagle Act. They tend to live near rivers, lakes and marshes and build their nests in large trees (reference (53)). Bald eagles have been sighted around Nelson Lake. |

#### 3.2.8.2 Environmental Setting

The Milton R. Young Station is located in a rural area that is dominated by agriculture. Original vegetation in the area included grasslands. The Milton R. Young Station is immediately adjacent to Nelson Lake and is generally surrounded by agricultural areas or other areas associated with the BNI Center Mine. Additionally, shrub and herb vegetation (Shrubland and Grassland) and small wooded areas are also present in the vicinity of the Milton R. Young Station. Land use and potential wildlife habitat features within a 3 km radius of the Milton R. Young Station include agriculture, Nelson Lake, Square Butte and Hagel Creeks, and small wooded areas.

# Chapter 4
# Direct and Indirect Impacts

## 4.1 Introduction

This chapter describes the direct and indirect impacts in sufficient detail to understand a change from the present as a result of the alternatives considered in detail (reference (2)). Direct impacts are those that are caused directly by the proposed activities at the same time and place (40 C.F.R. 1508.8(a)). Indirect impacts are those that are removed in time and place (40 C.F.R. 1508.8(b)). This chapter incorporates Chapter 3.0 of the BLM EA by reference and only provides supplemental information regarding air quality where relevant to the analysis presented in this document.

## 4.2 Air Quality and Climate Change

### 4.2.1 Emission Sources

#### 4.2.1.1 Direct Emissions

Particulate and gaseous air pollutants are emitted during the coal mining process. Sources of direct emissions from mining are fugitive emissions from coal excavation and reclamation activities and mobile (tailpipe) emissions from equipment. Fugitive particulate emissions result from dust being generated during dragline operations, coal haulage, bulldozers, scrapers, loaders, and other equipment operating on the Mine, coal stockpiles, and reclamation activities. Table 4-1 summarizes the annual emissions at the BNI Center Mine. Refer to Appendix A for details regarding emissions calculations. The fugitive emissions calculated for this EA use basic screening equations and actual production information at the BNI Center Mine. The screening equations provide high-end estimates that are intended to overestimate and not underestimate actual emissions. The BNI Center Mine currently operates under Minor Source Permit to Operate #O79004. DEQ sets standards to ensure operations under the Minor Source Permit are within state and federal air quality regulations. The permit lists the production rate of the mine as 4,000,000 to 4,600,000 tons of coal per year. The average production rate between 2015-2019 is 4,320,000 tons of coal per year with is in the middle of this range or 94% of the top end of the range. For comparison, refer to Appendix A for emissions from the top end of the production rate (maximum emissions). Actual emissions from BNI Center Mine are used in the analysis to provide meaningful comparisons to emissions from other sources.

For determining whether a source is a major source, the definitions of *major stationary source* and *major source* in PSD and Title V regulations, respectively, provide that fugitive emissions shall not be included unless the source belongs to one of the categories of sources specifically listed in the regulations. Mobile sources, such as haul trucks and excavators, do not require stationary source permits and are not subject to stationary source permitting thresholds. Additionally, fugitive dust emissions from sources not subject to requirements of section 111 or 112 of the CAA are not included in determining major source thresholds for the purposes of PSD or Title V applicability. 40 C.F.R. 52.21(b)(1)(iii) states that fugitive emissions of a stationary source shall not be included in determining whether a site is a major stationary source unless the source belongs to one of 27 named categories of stationary sources. Because surface mines are not one of the 27 listed source categories in 40 C.F.R. 52.21(b)(1)(iii), fugitive emissions from sources that are not subject to Chapter 111 or 112 of the CAA are not counted toward major source thresholds.

**Table 4-1 BNI Center Mine Direct Emissions, Average Annual for Whole Mine 2015-2019**

| Pollutant | Mobile | Blasting | Fugitives | Total | Units |
|---|---|---|---|---|---|
| $NO_X$ | 991.2 | 3.9 | n/a | 995.2 | tons |
| $SO_x$ | 19.2 | 0.5 | n/a | 19.7 | tons |
| CO | 572.3 | 15.4 | n/a | 587.7 | tons |
| PM | 30.8 | n/a | 1,188.9 | 1,219.6 | tons |
| $PM_{10}$ | 30.8 | n/a | 1,188.9 | 1,219.6 | tons |
| $PM_{2.5}$ | 30.8 | n/a | 114.7 | 145.4 | tons |
| $CO_2$ | 31,515 | n/a | n/a | 31,515 | metric tons |
| $CH_4$ | 1.3 | n/a | 843.6 | 844.9 | metric tons |
| $N_2O$ | 0.3 | n/a | n/a | 0.3 | metric tons |
| $CO_2e$ | 31,619 | n/a | 23,621.2 | 55,240 | metric tons |
| Black carbon | 23.1 | n/a | n/a | 23.1 | Tons |

Although the minor source permit does not establish emission limits for PM or any other pollutant, the BNI Center Mine has an opacity limit which constrains the amount of fugitive dust at the site at any one time and specifies fugitive dust control requirements. The BNI Center Mine is required to implement fugitive dust control measures listed in the air permit for the entire site, including areas of federal coal.

One air pollutant of note that is created during the surface coal mining process is black carbon. Black carbon is a light-absorbing, fine particulate ($PM_{2.5}$) that is formed by the incomplete combustion of fossil fuels, biofuels, and biomass. The Clean Air Task Force estimates that 75% of diesel particulate matter is black carbon (reference (54)). Based on the diesel combustion at the Mine, approximately 23.1 tons of black carbon was generated per year from 2015 to 2019.

Another group of pollutants is $NO_x$. $NO_x$ is formed when fuel is combusted, such as from vehicles, off-road equipment, fires, and power plants. These emissions can create particulate matter and ground-level $O_3$, as well as contribute to respiratory issues. $NO_x$ levels are tracked by the criteria pollutant $NO_2$. North Dakota is in attainment for $NO_2$ levels. $NO_x$ is created at the Mine by the burning of diesel and, in very small amounts, by coal blasting. Refer to Appendix A for calculations relating to tailpipe and blasting $NO_x$ emissions.

Greenhouse gas emissions are generated at the mine from mobile tailpipe emissions and surface emissions from mining operations. Fugitive $CH_4$ emissions from 1) exposure of the coal and other gas-bearing strata during mining operations (mining emissions), 2) coal processing or handling, and 3) coal storage and transportation. Most of the $CH_4$ generated would likely be emitted from the coal through natural fractures when it is uncovered and exposed by coal blasting and from the lower-most portion of the surface mine pit. Coal is uncovered in the pits and hauled out based on the mining sequence, which could be days, but could be longer (weeks or months), pending quality needs, pit slope accesses, dragline sequences, etc. Some

$CH_4$ that remains in the coal is liberated during processing (reference (55)). Following excavation and handling, very little $CH_4$ likely remains in the coal. Coal handling, storage, and transportation emissions are termed post-mining emissions. Both mining and post-mining emissions are included in emissions used in this analysis. Coal beds that have extensive subcrops near the surface, or outcrops at the surface, can naturally vent $CH_4$. This is a common feature occurring in North Dakota mining operations. Also, in North Dakota, many areas of minable coal are covered by porous and permeable glacial deposits. Coal beds tend to oxidize (soften) when directly overlain by glacial material. These conditions facilitate the natural venting of $CH_4$. Therefore, $CH_4$ can be released from North Dakota coal beds before mining operations. Refer to Appendix A for calculations relating to tailpipe and surface mining GHG emissions.

#### 4.2.1.2 Indirect Emissions

The Milton R. Young Station receives coal from the BNI Center Mine. The plant works by combusting coal to heat water, which generates steam. This steam turns a turbine connected to a generator. The generator produces electricity using magnets spinning against wire coils. The electricity is then delivered to customers through transmission lines. Annual criteria pollutants generated from combustion of BNI Center Mine coal are summarized in Table 3-6, HAPs emissions are summarized in Table 3-8, and GHG emissions are summarized in Table 3-12.

Milton R. Young Station is a major source and maintains a Title V Permit to Operate, issued by DEQ, as required for any operation that emits 100 tons per year or more of a criteria pollutant, or 10 tons per year of a HAP, or 25 tons per year or more of any combination of HAPs. Milton R. Young is equipped with pollution control technology that meets or exceeds the level of emission reductions required under DEQ and USEPA regulations (reference (56)).

#### 4.2.1.3 Mercury

Minnkota made a major investment of more than $425 million in environmental upgrades from 2006 to 2011 at the Milton R. Young Station (reference (25)). The primary upgrades were environmental controls for $SO_2$ and $NO_X$ on both units. The Milton R. Young Station installed equipment that achieves a minimum of 95 percent reduction in $SO_2$ emissions and 55 to 60 percent reduction in $NO_X$ emissions. The capital investment to remove $SO_2$ was $260 million and the $NO_X$ controls cost $34 million. Additional infrastructure to support the new systems required $132 million in electrical improvements. These technology changes for $SO_2$ and $NO_X$ also result in increased capture of mercury due to changing elemental mercury to oxidized mercury, and more capture of the oxidized mercury (reference (57)).

For 2019, mercury emissions from the Milton R. Young Station were estimated to be 174 pounds per year (lb/yr) (refer to Table 3-9). Minnkota has achieved a 55- to 60-percent reduction of mercury by employing Clean Coal Solutions technology, and by employing halogen and activated carbon injection (reference (25)). A halogen, such as bromide (as calcium bromide), serves to oxidize the mercury to allow it to be adsorbed by activated carbon, which is injected into the flue gas prior to the electrostatic precipitator. The mercury is then captured along with the fly ash in the precipitator; however this is done at such a low concentration that it is not detrimental to any use of fly ash, including disposal (reference (25)). The major beneficial use of coal fly ash in the US is as a pozzolanic additive in concrete (reference (58)). Studies have identified that mercury associated with fly ash is stable and is either not released to the environment or only released in small amounts whether used in the manufacture of other products or in ash disposal facilities (reference (59); reference (60)). The Milton R. Young Station sells a portion of the fly ash for use as an absorbent at a commercially permitted landfill (reference (25)).

Emission test results collected during emission control evaluations indicate that primarily elemental mercury is emitted from the Milton R. Young Station, with very little (<10%) of the emissions being oxidized or particle-bound (reference (61)). Emissions speciation from other North Dakota power plants assessing control technologies were similar, with primarily elemental mercury being emitted (reference (62)).

### Mercury Speciation and Relationship to Local Deposition

Mercury air emissions generally exist as one of three species: elemental, ionic or oxidized, and particle bound. Understanding which species are present is the key to determining mercury's atmospheric pathway, transport, and fate. As summarized by the Arctic Monitoring and Assessment Program/United Nations Environment Programme (reference (63)), the majority of anthropogenic mercury emissions and the most common species present in the atmosphere is gaseous elemental mercury. Elemental mercury has an atmospheric lifetime of several months to a year and is transported great distances. Elemental mercury when emitted to the atmosphere can readily travel for hundreds to thousands of kms (reference (64)). Due to its elemental properties and slow reaction with common atmospheric oxidants, very little if any gaseous elemental mercury is deposited to the earth's surface (reference (63)). Other factors that limit the local deposition of elemental mercury are the power plant's stack height and exhaust gas temperature that provide "lift" to the emissions plume (i.e., a buoyant plume) to elevate it above the vegetated landscape and provide for good dispersion away from the emission point.

Mercury deposition to land and water is predominantly in the form of oxidized mercury compounds, gaseous oxidized mercury or oxidized mercury attached to particles, both of which are due to the direct deposition of gas phase species, and through wet deposition of oxidized mercury in precipitation (reference (63)). Oxidized mercury is water-soluble and is deposited readily through precipitation at the local level (as defined by USEPA for their national-level modeling analysis, local in this case is within 10, and up to 100 km of, the emission point; (reference (20)). Ionic mercury, as a large ion, readily binds to other materials from associated emissions and as well as other materials in the atmosphere (reference (64)). Further, gaseous oxidized mercury is highly reactive with other environmental constituents and is deposited within a few miles of its emission point (reference (64)). The local deposition of oxidized mercury and its role in elevated fish tissue mercury concentrations has been documented in several regions of the U.S., for example in the southeast (reference (65)) and in New England (reference (66); reference (67)). In the evaluation by Florida DEP (reference (65)), oxidized mercury accounted for more than 50% of the emissions from the facilities being evaluated. King et al. (reference (67)) found that local mercury deposition due to emissions of oxidized mercury was a factor of 4 to 10 times greater than rural background deposition. Associated with increased local deposition of mercury, fish tissue mercury concentrations were elevated in nearby water bodies (reference (65); reference (67)). The available literature clearly concludes that when a significant portion of air emissions are oxidized mercury, there will be increased local mercury deposition.

Particle-bound mercury has a short atmospheric life due its physical characteristics (mass, increased wind resistance, interaction with precipitation) and is thought to be deposited within a range of 50 to 80 km (30-50 miles) from the emission point (reference (64)).

Additional research on mercury deposition around power plants provides a refinement to USEPA's modeling assessment (reference (20)). For example, in their assessment of emission source contributions to deposition, Laudal et al. (reference (68)) stated that North Dakota electric generating stations do not contribute significantly to local or regional mercury deposition due to the predominance of elemental Hg emitted from tall stacks. Sullivan et al. (reference (47)) conducted a modeling study of three power plants with total mercury emissions of 758 lb/yr, 355 lb/yr, and 2,104 lb/yr, respectively. Oxidized mercury emissions were estimated at 20%, 20%, and 60% of total mercury emissions, respectively. They found that the highest deposition rates occurred within 10 km of each facility but overall, less than 2% of total mercury emissions deposited within 15 km, of the power plants they evaluated, and the small percentages of deposition resulted in minor contributions to background mercury levels. The authors also found no correlation of modeled deposition with vegetation or soil concentrations; estimated total mercury deposition ranged between 0.3% to 1.7% of background; and there was no statistically significant enrichment of mercury in surface soils even within 10 km of each power plant. They also concluded that their modeling results were consistent with the literature they reviewed that found no "hot spots" of deposition close to power plants. A modeling analysis was conducted for a proposed baseload coal-fired power plant with total mercury emissions of approximately 136 lb/yr after controls (activated carbon and particulate control technology), with primarily elemental mercury emissions (97%). The modeling results identified that the highest estimated deposition was about 2% of background deposition, with the authors concluding that very little deposition of mercury was estimated to occur (reference (62)).

Based on the modeling and monitoring studies discussed above for mercury and for metals that identify maximum deposition occurs relatively close to power plants and background concentrations occur within 2 to 3 km of the emission source, a 3 km radius study area is considered sufficient to assess potential effects from deposition of mercury associated with coal combustion at the Milton R. Young Station.

#### 4.2.1.4 Metals

When assessing the potential deposition of chemicals emitted to the air from a specific facility, researchers have concluded that dry deposition is the primary contributor to local deposition (reference (69)). Dry deposition of particulate metals at the Milton R. Young Station is associated with emissions of particulate matter ($PM_{10}$ and $PM_{2.5}$). $PM_{2.5}$ are fine particles that can remain airborne for long periods of time and are generally associated with long range atmospheric transport and not associated with local deposition (reference (70)). $PM_{10}$ are coarser particles with a shorter atmospheric residence time and therefore tend to deposit closer to an emission source. The Milton R. Young Station has numerous pollution control systems including an electrostatic precipitator, flue gas desulfurization systems, and activated carbon injection system all of which serve to capture a portion of the pollutants that would otherwise be emitted. Given that the average $PM_{10}$ emissions at the Milton R. Young Station are 300 tons per year, there is some potential for local deposition of particulate metals. However, given the pollution control measures in place at the Milton R. Young Station and its stack height, local deposition of particulate metals is likely very minimal.

To provide additional perspective on the potential for particle-bound pollutants to affect nearby ecological receptors, particulate metal emissions for the Milton R. Young Station were compared to the lowest available USEPA (reference (71)) screening emission rates. As shown in Table 4-2, all estimated particulate metal emissions are below the lowest available screening emission rates (per USEPA 1980 guidance). These results are interpreted to mean that no significant deposition is expected to occur at receptors close to (i.e., within 3 km), or distant from (> 3 km), the source. Similarly, no significant effects are expected to occur close to, or distant from, the source.

**Table 4-2 Milton R. Young Station Metal Emissions and Comparison to USEPA (1980) Screening Emission Rates**

| | | | |
|---|---|---|---|
| Arsenic | 0.038 | 0.24 | 0.16 |
| Beryllium | 0.001 | 0.057(2) | 0.02 |
| Cadmium | 0.005 | 0.037 | 0.14 |
| Chromium | 0.35(3) | 1.10 | 0.32 |
| Cobalt | 0.008 | 1.20 | 0.01 |
| Copper | NA | 0.21 | NA |
| Manganese | 0.42 | 1.13(4) | 0.37 |
| Mercury | 0.1 | 61 | 0.002 |
| Nickel | 0.12 | 67 | 0.002 |
| Selenium | 0.17 | 1.70 | 0.1 |
| Vanadium | NA | 0.33 | NA |
| Zinc | NA | 63 | NA |

Note(s):

(1) Lowest screening emission rate from Table 5.7 of reference (71), unless otherwise noted.

(2) Screening emission rate for beryllium is from Table 5.6 of reference (71).

(3) Emissions are a sum of Chromium III and Chromium VI.

(4) The original USEPA (1980) emission rate was adjusted by a factor of 3.43 based on Table 5.8 of reference (71); a 30 m stack, “cold”.

NA = Not applicable/Data not available

## 4.2.2 Proposed Action

### 4.2.2.1 Direct Impacts

Mine operation under the Proposed Action at the Mine is not anticipated to substantially change. Emissions of air pollutants at the BNI Center Mine are currently limited by a production rate condition established in its air quality permit (reference (4)). Because the Proposed Action is a continuation (rather than an increase) of current surface mining, no permit modification would be required if the Proposed Action is implemented. Mining of Tract 1 (NDM-102083) federal coal would be subject to all conditions in the current air quality permit. The Proposed Action would not authorize a change in already permitted actions or in production levels; therefore, there would be no incremental increase in annual emissions from implementation of the Proposed Action. Mining would move from mined-out areas of BNI Center Mine into Tract 1 (NDM-102083). At an annual BNI Center Mine rate of approximately 4.0 million tons per year, the 1.69 million tons of federal coal to be mined from Tract 1 (NDM-102083) accounts for approximately five months of operations in total that will take place in smaller tonnages over seven years as shown in Table 4-3.

**Table 4-3 Mining Plan for Federal Coal in Tract 1 (NDM-102083)**

| Year | Tons of coal mined | Percent of Tract 1 NDM-102083 extractable coal | Percent of BNI Historical Annual Coal Mined |
|---|---|---|---|
| Year 1 | 96,000 | 6% | 2% |
| Year 2 | 109,000 | 7% | 3% |
| Year 3 | 264,000 | 16% | 6% |
| Year 4 | 251,000 | 15% | 6% |
| Year 5 | 510,000 | 31% | 12% |
| Year 6 | 318,000 | 20% | 7% |
| Year 7 | 76,000 | 5% | 2% |

The Proposed Action does not extend the life of the BNI Center Mine and the overall annual amount of direct emission of particulate and gaseous air pollution is also not anticipated to increase from current levels with the Proposed Action. No impacts to air quality would occur from the Proposed Action; however, impacts to air quality from surface mining are evaluated in this section for perspective. Mobile, fugitive and blasting emissions associated with the mining of federal coal in Tract 1 (NDM-102083) are each summarized in this section.

Direct emissions from equipment used to mine the Tract 1 (NDM-102083) federal coal in the Proposed Action were estimated using the average total hours per year from 2015 to 2019 that each fleet-type was operated and the emission factors for that engine. Emission factors for hydrocarbons, $NO_x$, CO, and PM were based on typical engine manufacturer guaranteed rates. Calculations were completed using the formula: tons of emissions=(x g/kw-hr*y kw*z average total hours)/907,185 g. As a conservative estimate, it was assumed that all HC/$NO_x$ was emitted as $NO_x$. The emission factor for $CO_2$ was derived from the amount of diesel fuel used. Emission factors for $SO_X$ and TOC were taken from USEPA's *AP-42, Compilation of Air Pollutant*

*Emission Factors, Volume 1: Stationary Point and Area Sources* (reference (41)). These amounts are reported in Table 4-4.

**Table 4-4 Direct Fleet Emissions from Tract 1 (NDM-102083) Federal Coal (tons over all seven years)**

| Fleet[1] | $NO_x$[2,3] | $SO_X$[4] | CO[2] | $PM_{10}$[2] | $PM_{2.5}$[2] |
|---|---|---|---|---|---|
| Hydraulic Shovels | 1 | 0.23 | 0.6 | 0.0 | 0.0 |
| Rubber Tire Dozers | 39 | 0.04 | 21.1 | 1.2 | 1.2 |
| Track Dozers (D6-D10T) | 7 | 2.33 | 6.5 | 0.4 | 0.4 |
| Track Dozers (D11T) | 29 | 0.03 | 15.7 | 0.9 | 0.9 |
| Front End Loaders | 66 | 0.05 | 76.7 | 3.6 | 3.6 |
| Motor Graders | 15 | 4.66 | 13.1 | 0.7 | 0.7 |
| Scrapers | 23 | 0.03 | 12.4 | 0.7 | 0.7 |
| Coal Haulers | 49 | 0.06 | 26.6 | 1.5 | 1.5 |
| Overburden Truck Fleet | 93 | 0.11 | 51.1 | 2.9 | 2.9 |
| *Total* | *322* | *7.5* | *224* | *12* | *12* |

[1] Calculations were completed using the formula: tons of emissions=(x lb/hp-hr*y hp*z average total hours)/2,000 lb

[2] Emission factors from engine manufacturer data. Calculations were completed using the formula: tons of emissions=(x g/kw-hr*y kw*z average total hours)/907,185 g

[3] Assumed value based on combined $NO_x$ and HC certifications, with the exception of the front-end loaders, which had a direct $NO_x$ emission factor

[4] Emission factors from USEPA's *AP-42* Chapter 3 Sections 3 and 4 reference (41). Calculations were completed using the formula: tons of emissions=(x lb/hp-hr*y hp*z average total hours)/2,000 lb Based on historical ANFO usage for blasting coal, an estimated 3,250 pounds $NO_x$, 420 pounds $SO_2$, and 13,000 pounds CO would be generated from the overall five months of mining in the Tract 1 (NDM-102083) federal coal. Assuming the amount of diesel fuel combusted stays consistent with historical usage, the amount of black carbon generated from mining the Tract 1 (NDM-102083) federal coal in the Proposed Action would be approximately 10 tons.

Direct fugitive emissions are generated from mine and vehicle activities related to coal extraction, stockpiling, reclamation, and vehicle traffic. Dust suppression techniques are utilized throughout BNI Center Mine operations to manage fugitive particulate emissions will apply to mining operations of both federal and non-federal coal. Table 4-5 shows the anticipated direct fugitive emissions related to mining the Tract 1 (NDM-102083) federal coal. Details regarding the calculation of fugitive emissions are in Appendix A.

**Table 4-5 Estimated Direct Fugitive Emissions from Tract 1 (NDM-102083) Federal Coal Activities (tons over seven years)**

| Fugitive Sources[1] | $PM_{10}$, tons | $PM_{2.5}$, tons |
|---|---|---|
| Road Emissions | 437.9 | 43.8 |
| Truck Loading | 1.7 | 0.04 |
| Bull Dozing | 19.8 | 0.6 |
| Dragline | 1.9 | 0.04 |
| Grading | 3.6 | 0.2 |
| Active Storage Pile | 0.2 | 0.2 |
| Total | 465.1 | 44.9 |

[1] Emission Factors developed from factors in *AP-42* Chapter 13 Section 2.2 and Chapter 11 Section 9 (reference (41))

GHG emissions from mobile sources at the mine were determined using estimated fuel usage and surface emissions of $CH_4$ related to mining activities and post-mining releases were calculated using historical coal production rates (Table 4-6). The direct GHG emissions anticipated for the Proposed Action Details regarding these calculations are in Appendix A.

**Table 4-6 Estimated Direct GHG Emissions from Tract 1 (NDM-102083) Federal Coal Activities (metric tons over seven years)**

| Pollutant | Tailpipe emissions | Surface mining | Post-mining surface | Total |
|---|---|---|---|---|
| $CO_2$ | 12,330 | n/a | n/a | 12,330 |
| $CH_4$ | 0.5 | 272 | 58 | 331 |
| $N_2O$ | 0.1 | n/a | n/a | 0.1 |
| $CO_2e$ | 12,370 | 7,609 | 1,633 | 21,612 |

Refer to Appendix A for details regarding direct emissions calculations**.** To provide perspective on the direct emissions generated from Tract 1 (NDM-102083) over the duration mining of this federal coal will take place, Table 4-7 shows the emissions, including fleet emissions, permitted emission points, blasting, and fugitive emissions from both the proposed mining of Tract 1 (NDM-102083) federal coal and coal from other non-federal coal over the entire seven year period during which Tract 1 (NDM-102083) federal coal is to be mined. On an annual basis, Table 4-8 summarizes the direct emissions during each year of the mine plan for Tract 1 (NDM-102083) federal coal as well as the historical annual emissions from the BNI Center Mine over the 2015-2019 time period. Compared to total North Dakota state emissions of hundreds of thousands of tons (Section 5.2.1) the direct emissions from BNI Center Mine are minor, even less than one percent of statewide emissions. As such, impacts of direct emissions from the Proposed Action would be minor and relatively short-term, staying in compliance with existing state air permits and NAAQS.

**Table 4-7 Total Direct Emissions over Seven Years**

| Pollutant | From Tract 1 lease tract coal, tons (A) | From coal not in Tract 1 lease tract, tons (B) | Total BNI Center Mine coal, tons (A+B) |
|---|---|---|---|
| $NO_X$ | 389 | 6,577 | 6,966 |
| $SO_X$ | 7.7 | 130 | 138 |
| CO | 230 | 3,884 | 4,114 |
| $PM_{10}$ | 477 | 8,060 | 8,538 |
| $PM_{2.5}$ | 56.9 | 961 | 1,018 |
| $CO_2$ | 12,330 | 208,275 | 220,605 |
| $CH_4$ | 331 | 5,584 | 5,914 |
| $N_2O$ | 0.1 | 1.7 | 1.8 |
| $CO_2e$ | 21,612 | 365,067 | 386,679 |
| Black carbon | 9.0 | 153 | 162 |

**Table 4-8 Total Annual Direct Emissions Each Year of Mining Tract 1 (NDM-102083)**

| Pollutant | From Tract 1 lease tract coal, Year 1 | From Tract 1 lease tract coal, Year 2 | From Tract 1 lease tract coal, Year 3 | From Tract 1 lease tract coal, Year 4 | From Tract 1 lease tract coal, Year 5 | From Tract 1 lease tract coal, Year 6 | From Tract 1 lease tract coal, Year 7 | 2015-2019 Average Annual BNI Center Mine Total | Units |
|---|---|---|---|---|---|---|---|---|---|
| $NO_X$ | 23 | 26 | 63 | 60 | 122 | 76 | 18 | 995 | tons |
| $SO_X$ | 0.5 | 0.5 | 1.3 | 1.2 | 2.4 | 1.5 | 0.4 | 19.7 | tons |
| CO | 14 | 15 | 37 | 36 | 72 | 45 | 11 | 588 | tons |
| $PM_{10}$ | 28 | 32 | 78 | 74 | 150 | 93 | 22 | 1,220 | tons |
| $PM_{2.5}$ | 3.4 | 3.8 | 9.3 | 8.8 | 17.9 | 11.1 | 2.7 | 145.4 | tons |
| $CO_2$ | 729 | 828 | 2,004 | 1,906 | 3,872 | 2,414 | 577 | 31,515 | metric tons |
| $CH_4$ | 20 | 22 | 54 | 51 | 104 | 65 | 15 | 845 | metric tons |
| $N_2O$ | 0.01 | 0.01 | 0.02 | 0.02 | 0.03 | 0.02 | 0.00 | 0.26 | metric tons |
| $CO_2e$ | 1,278 | 1,451 | 3,513 | 3,340 | 6,787 | 4,232 | 1,011 | 55,240 | metric tons |
| Black carbon | 0.5 | 0.6 | 1.5 | 1.4 | 2.8 | 1.8 | 0.4 | 23.1 | Tons |

#### 4.2.2.2 Indirect Impacts

Indirect air pollutant emissions from the combustion of the coal mined from Tract 1 (NDM-102083) can be estimated using current emissions and throughput from the Milton R. Young Station. The average annual coal throughput for 2015-2019 at Milton R. Young Station was approximately 4,320,000 tons (Permit No. O16017, Section 3.3.1.1.3). BNI Center Mine is assumed to be the sole provider of coal to this facility. Emission data was derived from NEI data and DEQ and Annual Emissions Inventory Reports (2015-2019). Tract 1 (NDM-102083) coal combusted each year at Milton R. Young was then estimated based on the average annual amount of coal combusted from 2015-2019. Emissions from the burning of Tract 1 (NDM-102083) coal would not change the total annual emissions at the Milton R. Young Station because the amount of coal produced at BNI Center Mine and delivered to the station would be essentially unchanged from current production levels. The emission estimates for all seven years of the mine plan for Tract 1 lease tract are located in Table 4-9.

**Table 4-9 Estimated Indirect Annual Emissions over Seven Years for Tract 1 (NDM-102083) Coal in the Proposed Action**

| Pollutant | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Unit |
|---|---|---|---|---|---|---|---|---|
| $PM_{10}$ | 6.7 | 7.6 | 18.3 | 17.4 | 35.4 | 22.1 | 5.3 | tons |
| $PM_{2.5}$ | 0.7 | 0.8 | 1.9 | 1.8 | 3.8 | 2.3 | 0.6 | tons |
| $SO_2$ | 63.2 | 71.8 | 173.8 | 165.3 | 335.8 | 209.4 | 50.0 | tons |
| $NO_x$ | 199.8 | 226.8 | 549.3 | 522.3 | 1061.2 | 661.7 | 158.1 | tons |
| CO | 3.2 | 3.7 | 8.9 | 8.5 | 17.2 | 10.8 | 2.6 | tons |
| TOC | 3.3 | 3.8 | 9.1 | 8.6 | 17.6 | 11.0 | 2.6 | tons |
| Ammonia | 0.3 | 0.3 | 0.8 | 0.7 | 1.5 | 0.9 | 0.2 | tons |
| Mercury | 4.0 | 4.5 | 10.9 | 10.3 | 21.0 | 13.1 | 3.1 | lbs |
| Total Metals | 54.8 | 62.2 | 150.7 | 143.2 | 291.0 | 181.5 | 43.4 | lbs |
| Total HAPs and VOC | 0.9 | 1.0 | 2.4 | 2.3 | 4.6 | 2.9 | 0.7 | lbs |
| HCl | 0.5 | 0.5 | 1.3 | 1.2 | 2.5 | 1.6 | 0.4 | tons |
| HF | 0.5 | 0.5 | 1.3 | 1.2 | 2.5 | 1.6 | 0.4 | tons |
| $CO_2$ | 133,306 | 151,358 | 366,591 | 348,539 | 708,187 | 441,575 | 105,534 | metric tons |
| $CH_4$ | 15.0 | 17.0 | 41.3 | 39.2 | 79.7 | 49.7 | 11.9 | metric tons |
| $N_2O$ | 2.2 | 2.5 | 6.0 | 5.7 | 11.6 | 7.2 | 1.7 | metric tons |
| $CO_2e$ | 134,304 | 152,491 | 369,337 | 351,150 | 713,491 | 444,883 | 106,324 | metric tons |

Source: Milton R. Young Air Emission Inventory Reports provided by BNI and 2017 NEI (reference (14))

For comparison, the total indirect emissions from the combustion of all coal mined at the BNI Center Mine for the period 2015-2019 are shown in Table 3-6, Table 3-8, and Table 3-12*.* Emissions related to the Proposed Action would be minor and short-term by providing the small tonnages of coal over seven years which in total are equivalent to five months of operation. The Proposed Action is not expected to cause NAAQS exceedances or near exceedances, nor exceed PSD Class I and II increment consumption.

Greenhouse gas emissions under the Proposed Action are expected to be minor compared to state emissions. Annually, GHG emissions from the combustion of Tract 1 (NDM-102083) coal at the Milton R. Young Station account for approximately 0.3-2% of the North Dakota GHG inventory and approximately 0.002-0.012% of the total US GHG inventory during the seven year plan for mining Tract (NDM-102083) coal (reference (40), (40)).

Lignite coal from the BNI Center Mine would continue to be combusted at Milton R. Young Station even if the mining of the Tract 1 (NDM-102083) coal did not occur. As shown in Table 4-9, emissions of GHG, criteria pollutants, and HAPs, from coal combustion would be minor and allocated over a period of seven years while remaining in compliance with state issued permits and NAAQS.

Overall, no significant impacts from mercury are expected to be associated with the combustion of Tract 1 (NDM-102083) federal coal in the Milton R. Young Station based on the following:

- Mercury emissions from the Milton R. Young Station will not change due to the combustion of Tract 1 (NDM-102083) federal coal

- The Milton R. Young Station has reduced mercury emissions and is using best available control technology to capture mercury
- Local mercury deposition to Nelson Lake and its watershed is primarily from existing background conditions, with likely very little contribution from the Milton R. Young Station based on findings for other coal-fired power plants reported in the available literature.
- Local fish consumption advisories for Nelson Lake have been in effect since the early 2000s and will not change due to the Proposed Action

As shown in Table 4-2, all estimated particulate metal emissions are below the lowest available screening emission rates (per USEPA 1980 guidance). The Proposed Action will not increase emissions from the Milton R. Young Station, nor materially change the emissions from the Milton R. Young Station. The characteristics of the Tract 1 (NDM-102083) coal will be similar to the coal currently being fired at the Milton R. Young Station. Based on the available literature, there is some potential for particulate metals associated with $PM_{10}$ to deposit locally. Some portion of the metals bound to the particulate may become bioavailable in the environment. However, previous studies of metal deposition near power plants found minimal contributions from the emission source to the local area (within 3 km of the source) and metal concentrations were at background levels within 2 to 3 km of the facility. In addition, Table 4-2 identifies that metal emission rates from the Milton R. Young Station are well below screening emission rates, further indicating no significant effects to ecological receptors close to, or at distance from, the facility. The results from those previous studies of power plants with control equipment are considered applicable to the assessment area around the Milton R. Young Station. The weight-of-evidence indicates that some particulate metal deposition likely occurs around the Milton R. Young Station, and any current deposition of these metals is likely minimal given the pollution reduction measures in place at the Milton R. Young Station and its stack height that allows for good dispersion away from the source. Regarding potential effects on the threatened and endangered species (Section 3.2.8.1) from deposition of mercury and other metals produced from the combustion of federal coal in Tract 1 (NDM-102083), OSMRE determined that there would be no effect to threatened and endangered species or designated critical habitat due to the fact that metal emission rates from the Milton R. Young Station are below USEPA screening rates and metal concentrations near power plants in general have been historically shown to be at background levels within 2 to 3 km of the emissions source. .

### 4.2.3 No Action

Under the No Action Alternative, ASLM would not approve the mining plan to recover federal coal resources contained in Tract 1 (NDM-102083), and they would not be developed. The projected mine life and operating plans of the BNI Center Mine, whether Tract 1 (NDM-102083) is leased or not, are anticipated to extend through the year 2037. Therefore, although Tract 1 (NDM-102083) would not be mined under this alternative, the BNI Center Mine would continue to operate at current production levels and emit approximately the same amount of annual air pollution by continuing mining in areas adjacent to Tract 1 (NDM-102083). Emissions of air pollutants at the BNI Center Mine associated with mining of areas adjacent to Tract 1 (NDM-

102083) would continue to be limited by a production rate condition established in its air quality permit (reference (4)). Existing sources of air pollution (such as the Milton R. Young Station) would also continue to impact air quality in the analysis area. Therefore, under this alternative, direct and indirect emissions would be similar to the Proposed Action.

# Chapter 5
# Cumulative Impacts

## 5.1 Introduction

Cumulative impacts are defined as “the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable actions regardless of what agency (federal or non-federal) or person undertakes such other actions. Cumulative impacts can result from individually minor, but collectively significant actions taking place over a period of time” (40 C.F.R. 1508.7). This chapter incorporates Chapter 4.0 of the BLM EA by reference and only provides supplemental information regarding air quality where relevant to the analysis presented in this document.

### 5.1.1 Analysis Areas

For the purposes of this analysis, the temporal span of the Proposed Action represents the time during which Tract 1 (NDM-102083) would be mined (i.e., five months of mining over seven years). The geographic extent of cumulative impacts includes Oliver County and adjacent counties Burleigh County, Mercer County, McLean County, and Morton County. For assessing potential deposition impacts, the geographic extent is relatively narrow and includes the area within 3 km of the Milton R. Young Station as the highest deposition occurs relatively close to an emission source. For climate change, the analysis area includes the state of North Dakota. No significant, adverse, cumulative effects were identified in the cumulative effects analysis.

### 5.1.2 Past, Present, and Reasonably Foreseeable Actions

Past and present actions in the air quality and climate change analysis area that would contribute to cumulative effects include mining activities, power plants, industrial activities, and agricultural activities. Of these activities surface mining and the associated electrical power generation dominate the emissions of the analysis area. Table 5-1 provides an overview of current actions. In addition to these sources, agriculture, including row crops, hayfields and grazing lands, is a predominant industry in North Dakota. Although there is significant oil and gas development in North Dakota, notably in the Bakken Region, there is little oil and gas development in the analysis area.

**Table 5-1 Summary of Present Actions in the Cumulative Effects Analysis Area**

| Activity | Site Name | County | Annual Production Status |
|---|---|---|---|
| Surface coal mine | Beulah Mine | Mercer | 0.5 MMT |
| Surface coal mine | Center Mine | Oliver | 4 MMT |
| Surface coal mine | Coyote Creek Mine | Mercer | 2.5 MMT |
| Surface coal mine | Falkirk Mine | McLean | 8 MMT |
| Surface coal mine | Freedom Mine | Mercer | 14 MMT |
| Electric power generation | Antelope Valley | Mercer | 900 MW |
| Electric power generation | Coal Creek Station | McLean | 1,100 MW |
| Electric power generation | Coyote | Mercer | 414 MW |
| Electric power generation | Leland Olds | Mercer | 656 MW |
| Electric power generation | Milton R. Young | Oliver | 705 MW |
| Electric power generation | R M Heskett | Morton | 100 MW |
| Electric power generation | Stanton | Mercer | 202 MW |
| Refinery | Marathon Petroleum Mandan | Morton | 73,800 BBL |
| Coal Gasification (coal to natural gas) | Synfuels | Mercer | 153 MMCF |
| Ethanol Production | Blue Flint | McLean | 50 MMGAL |
| Ethanol Production | Red Tail Energy | Mercer | 50 MMGAL |

Source: USEIA 2018 Annual Coal Report (reference (38)) and NDSU (reference (72))

Reasonably foreseeable future actions are decisions, funding, or formal proposals that are either existing or are highly probable, based on known opportunities or trends. There are no known new reasonably foreseeable actions in the cumulative impacts analysis area associated with electric power generation, or other industrial development. Mining operations at BNI Center Mine would continue through 2037. Mining operations at Beulah Mine, Coyote Creek Mine, Falkirk Mine, and Freedom Mine are expected to continue for the foreseeable future with continued surface disturbances according to individual mine plans. No modifications or mine expansions are expected to occur in the reasonably foreseeable future.

## 5.2 Cumulative Impacts

### 5.2.1 Air Quality and Climate Change

#### 5.2.1.1 Criteria and HAPs Pollutants

Air emissions from past and present actions are currently considered in the air quality monitoring data in the state of North Dakota. As such, any cumulative air quality impacts from past and present actions are reflected in the local air quality monitoring data at the NDDH's Hanover ambient air monitoring site. The 2018 reported levels did not exceed any NAAQS, and did not show any clear trends of increasing or decreasing ambient concentrations (Table 3-2). Additionally, the state of North Dakota has been classified as in attainment for NAAQS for all criteria pollutants that are classifiable in North Dakota. The Proposed Action would not increase production at the Mine or combustion at the Milton R. Young Station, which received essentially all coal mined at the BNI Center Mine. As a result, the Proposed Action will extend the life of the mine by approximately five months, however, no changes to annual emissions of criteria pollutants, HAPs, or GHG are expected from the Proposed Action. For perspective, the maximum annual contribution of emissions from the Proposed Action in comparison with total reported statewide emissions in North Dakota is provided in Table 5-2. Contributions from the Proposed Action would be spread over seven years of mining. It is important to note that the reportable statewide emissions do not generally include fugitive emissions or tailpipe emissions, both of which are included in the direct emissions from the Proposed Action. Therefore, the relative contribution of direct and indirect emissions from the Proposed Action is overstated.

**Table 5-2 North Dakota and Tract 1 (NDM-102083) Criteria Pollutant and GHG Emissions**

| Pollutant | 2019 Reported[1] Total North Dakota Emissions | Max Annual Direct Emissions[2] Tract 1 Lease Tract | Max Annual Indirect Emissions Tract 1 Lease Tract | Direct + Indirect Tract 1 Lease Tract Emissions Percent of ND Emissions[3] | Units |
|---|---|---|---|---|---|
| CO | 318,993 | 72 | 17.2 | 0.03% | tons |
| $NO_x$ | 141,215 | 122 | 1,061 | 0.8% | tons |
| $PM_{10}$ | 365,267 | 150 | 35.4 | 0.05% | tons |
| $PM_{2.5}$ | 77,568 | 17.9 | 3.8 | 0.03% | tons |
| $SO_2$ | 101,563 | 2.4 | 336 | 0.3% | tons |
| VOC | 437,010 | n/a | 17.6 | 0.004% | tons |
| $CO_2e$ | 41,000,000 | 6,787 | 713,491 | 1.8% | metric tons |

Source: USEPA State Tier 1 Inventory (reference (73)) for statewide criteria pollutant emissions and USEPA FLIGHT for GHG emissions Direct and indirect emissions are as presented in Table 3-11 and Table 3-12 Maximum annual emissions are for Year 5 of the Tract 1 lease tract mine plan as Year 5 has highest tonnage of Tract 1 coal mined.

[1] Reported emissions generally do not include fugitive emissions or tailpipe emissions.

[2] Direct emissions calculated for this EA include fugitive dust and tailpipe emissions.

[3] Percent is calculated using available reportable emissions data for the State of ND, which does not include fugitive dust emissions or tailpipe emissions, which are included in direct Tract 1 lease tract emissions. Therefore, percentages of statewide emissions should be considered high-end estimates.

Contributions to the measured criteria pollutant levels at the Hanover monitoring site are expected to remain the same in the future as they were when the 2018 results were measured. Because the Proposed Action is a continuation of current surface mining, there would be no increase in annual production levels at the BNI Center Mine and no incremental increase in the emissions rates at either the BNI Center Mine or the Milton R. Young Station. Thus, no significant cumulative impact to air quality would occur if the Proposed Action were implemented compared to the No Action.

#### 5.2.1.2 Greenhouse Gases and Climate Change

Climate change associated with GHG emissions is a global phenomenon and emissions from any one source or regional sector does not remain localized or necessarily result in local impacts. The relative contribution of the Proposed Action, the BNI Center Mine in general, and the indirect emissions from combustion of coal from the Mine is overwhelmed by the global GHG emission inventory and unlikely to influence overall global cumulative emissions. Emissions of GHG resulting from the Proposed Action would, however, continue to increase the atmosphere's concentration of GHG, and, in combination with past, present, and future emissions from all other sources, contribute incrementally, to the global warming that produces the adverse effects of climate change described previously (Section 3.2.7).

Trends in the US GHG inventory, however, may provide context to the contributions of the Proposed Action. USEPA completes an annual inventory of GHG across the U.S. and presents trends in GHG emissions in the US. The most recent inventory shows a general trend of decreasing greenhouse gas emissions over the past ten years, with a 7 percent decrease from 2008 to 2018 levels (reference (39)). The 2018 total U.S. greenhouse gas emissions equaled 6,677 MMT of $CO_2$ equivalents. The maximum annual GHG emissions from the Proposed Action is approximately 0.01% of the US inventory. In the 2018 US inventory, transportation was the largest source of these emissions, comprising 28 percent of the total, followed by electricity production (27 percent), industry (22 percent), and agriculture (10 percent) (reference (39)). Overall trends by sector in the US have been flat since 2008 for all sectors, with the exception of the electric power industry, which shows a decreasing trend (reference (39)). Within the electric power industry coal combustion contributes the majority of GHG emissions.

Though total greenhouse gas emission levels from mining operations and emissions from Milton R. Young Station have been calculated for this EA (refer to Table 4-7 and Table 3-12), current limitations in the climate change earth systems modeling make it impossible to directly link the emissions from a single action to an effect on climate change. For perspective, the direct and indirect GHG emissions associated with BNI coal in 2018 are compared in Table 5-3 to global, national, and regional GHG emissions.

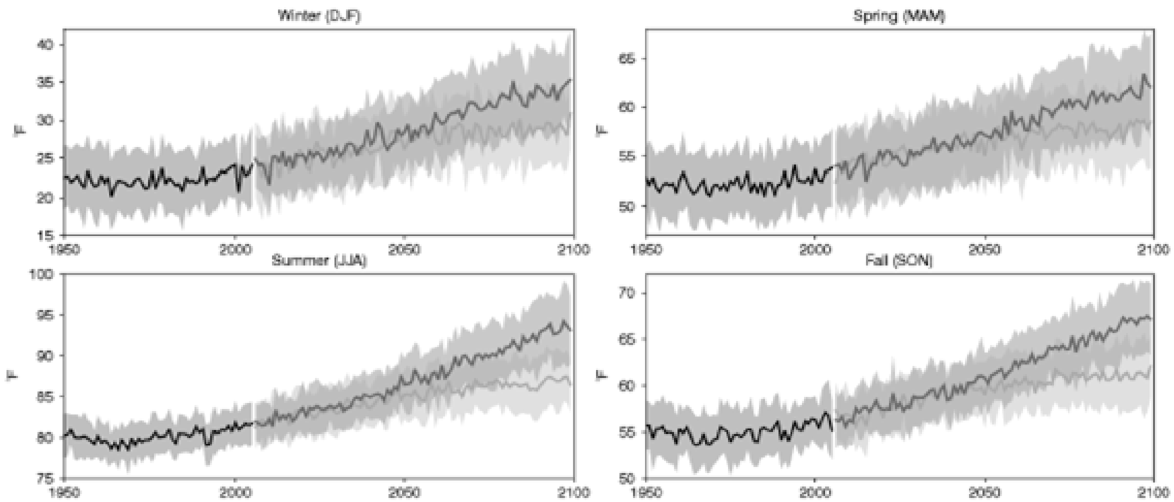
**Table 5-3 Comparison of 2018 Greenhouse Gas Emissions**

| Description | GHG Emissions, MMT $CO_2e$ |
|---|---|
| Global | 55,300 |
| Global from Fossil Fuel | 37,500 |
| US Total | 6,678 |
| US Electric Power Industry | 1,799 |
| US Coal Mining | 52.7 |
| North Dakota Total | 41 |
| Indirect BNI at Milton R. Young Station | 6 |
| Direct at BNI Center Mine | 0.06 |

Climate change models, however, may be used to assess potential Climate change impacts in general. The Fifth Assessment Report of the IPCC (reference (31)) summarizes data from 30 different global climate models that evaluate the natural systems and feedback mechanisms contributing to climate variability. A range of global GHG emissions scenarios known as representative concentration pathways (RCP) were considered in the modeling analysis to assess potential degrees of climate change impacts. A stringent mitigation scenario (RCP2.6), a low emissions scenario (RCP4.5), an intermediate emissions scenario (RCP 6.0), and an aggressive emissions scenario (RCP8.5) were evaluated in the report. These scenarios correspond to atmospheric concentrations of $CO_2$ by the year 2100 of 421 ppm for RCP2.6, 538 ppm for RCP4.5, 670 ppm for RCP6.0, and 936 ppm for RCP8.5. The range of likely change in global surface temperature by 2050 ranges from 0.3 to 1 degree Celsius for the RCP2.6 scenario and from 0.5 to 2.0 degrees Celsius for the RCP8.5 scenario. Generally, the more stringent climate change mitigation, the lower the projected change in global surface temperatures. When discussing regional impacts, however, it is important to note that degrees of surface temperature increases vary from region to region.

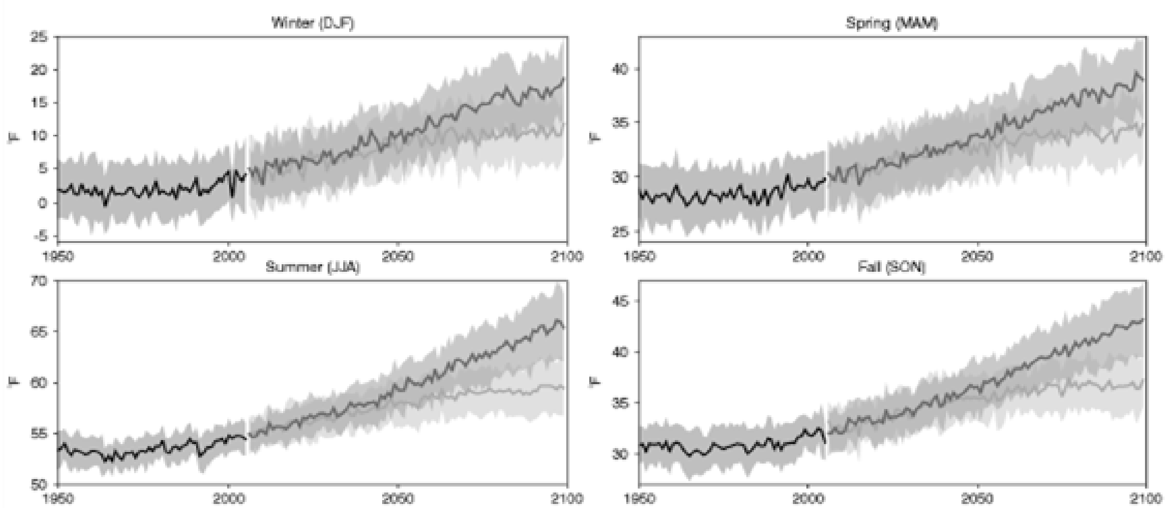
To discuss the cumulative impacts of GHG emissions for the project area, regional-scale projected impacts are discussed for the state of North Dakota. The USGS National Climate Change Viewer (reference (74)) can be used to evaluate potential climate change at the state level. The viewer provides data showing projections of future climate trends under RCP emission scenarios RCP4.5 and RCP8.5. Data presented in the USGS Climate Change Viewer data can also be extrapolated to get a general understanding of impacts under RCP2.6 and RCP6.0. Generally, the RCP2.6 scenario can be assumed to contribute to a lesser degree of climate change impacts in the region, while the RCP6.0 can be assumed to contribute to impacts that are of lesser magnitude than RCP8.5 but of greater magnitude than RCP4.5. Projected changes to the maximum and minimum temperature and precipitation for North Dakota are presented for RCP4.5 and RCP8.5 to assess regional cumulative impacts from GHG emissions in Figure 5-1, Figure 5-2, and Figure 5-3. The RCP4.5 and RCP8.5 scenarios forecast similar levels of climate impacts in the region over the next few decades; however, impacts over the next century diverge significantly. Because of uncertainties in the climate models, especially toward the end of the century, the impacts projected represent a forecast but are not certain to occur at the magnitudes projected.

Seasonal time series of maximum 2 m air temperature, minimum 2 m air temperature, and precipitation are shown in Figure 5-1, Figure 5-2, and Figure 5-3 respectively (reference (75)). Historical data is shown up to 2005 and projected data from 2006. In the projected data, the average of 30 global climate change models for RCP4.5 (lower line) and RCP8.5 (upper line) is indicated by the solid lines, and their standard deviations are indicated by the respective shaded areas.



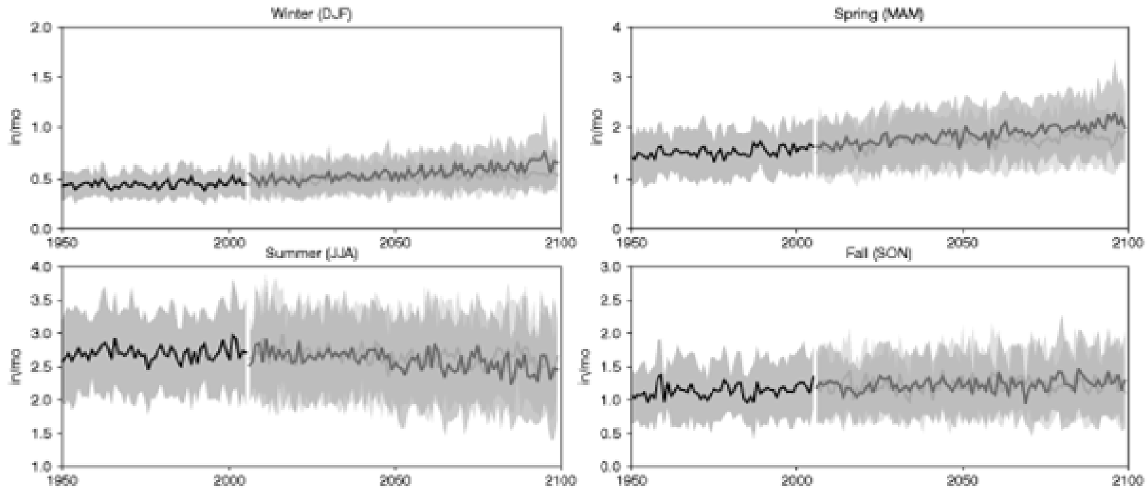

Source: Reference (75)

**Figure 5-1 Climate Change Viewer 2-meter Maximum Air Temperature for North Dakota**




Source: Reference (75)

**Figure 5-2 Climate Change Viewer 2-meter Minimum Air Temperature for North Dakota**




Source: Reference (75)

**Figure 5-3 Climate Change Viewer Precipitation for North Dakota**

Overall, the RCP8.5 scenario representing the aggressive emission scenario results in higher seasonal average maximum and minimum temperature projections over the century in comparison to the RCP4.5 scenario. Both scenarios project an increase over the historical average over the next century. The temperature projections for both the RCP scenarios available in USGS data around the mid-century are fairly consistent with most of the divergence in the scenarios being realized in the latter half of the century. By 2050, the seasonal maximum and minimum temperatures in North Dakota are projected to increase by roughly 2.5°F based on the average of the global climate change models. Thus, the uncertainty in the estimates shown in the shaded areas of Figure 5-1, Figure 5-2, and Figure 5-3 for both the RCP4.5 and RCP8.5 scenarios out to 2040 show that the level of uncertainty in the projections range from 5°F to 10°F depending on the season. Therefore, it is difficult to definitively state that the cumulative impacts at the mid-century mark will result in a specific magnitude of warming in the region. However, there is a definitive upward trend in seasonal minimum and maximum temperatures.

Rainfall data have a much less distinct trend, and the level of uncertainty over the next century shows that seasonal average rainfall may remain within the range that is currently typical for North Dakota. However, based on the average projections of the climate change models, there is projected to be a slight increase in winter and spring average precipitation and a slight decrease in summer precipitation. This trend is stronger based on the RCP8.5 scenario.

The Proposed Action is a continuation of existing activities at the BNI Center Mine and will contribute to atmospheric concentrations of GHG, however, the degree that these emissions will contribute to climate change impacts is relatively small and the rate of contribution to cumulative climate change would be similar under both the Proposed Action and the No Action.

### 5.2.2 Visibility

Visibility conditions and visibility degradation is associated with light scattering particles. Although some light-scattering particles are associated with primary emissions (e.g., PM2.5), others, such as ammonium nitrate and ammonium sulfate particles are secondary particulate formed in the atmosphere via chemical transformation of precursor emissions such as $NO_X$ and $SO_2$. Due to the nature of these emissions and the chemical transformation processes that occur in the atmosphere, visibility degradation is influenced by meteorological conditions and long range transport as well as source emissions (reference (76)). It is therefore unlikely that incremental changes at any source would have a long-term impact on visibility in North Dakota Class I areas. Additionally, the Proposed Action and the cumulative analysis area is generally downwind of all North Dakota Class I areas reducing the impact of sources in this area on Class I visibility conditions.

The Proposed Action is a continuation of current mining production rates, therefore, the rate of direct and indirect emissions from BNI Center Mine operations is expected to remain unchanged. Furthermore, there are no known reasonably foreseeable actions in the analysis area that would change emission trends for precursors of light scattering particles. As such, trends in visibility conditions in North Dakota Class I areas are expected to continue in the future. IMPROVE annual summary data from 2000 to 2018 is shown in Figure 5-4 and Figure 5-5. At both LNWA and TRNP, there are gradual decreasing trends in visibility degradation for both the 20% best visibility days and 20% worst visibility days. These trends are expected to remain unchanged by the Proposed Action.

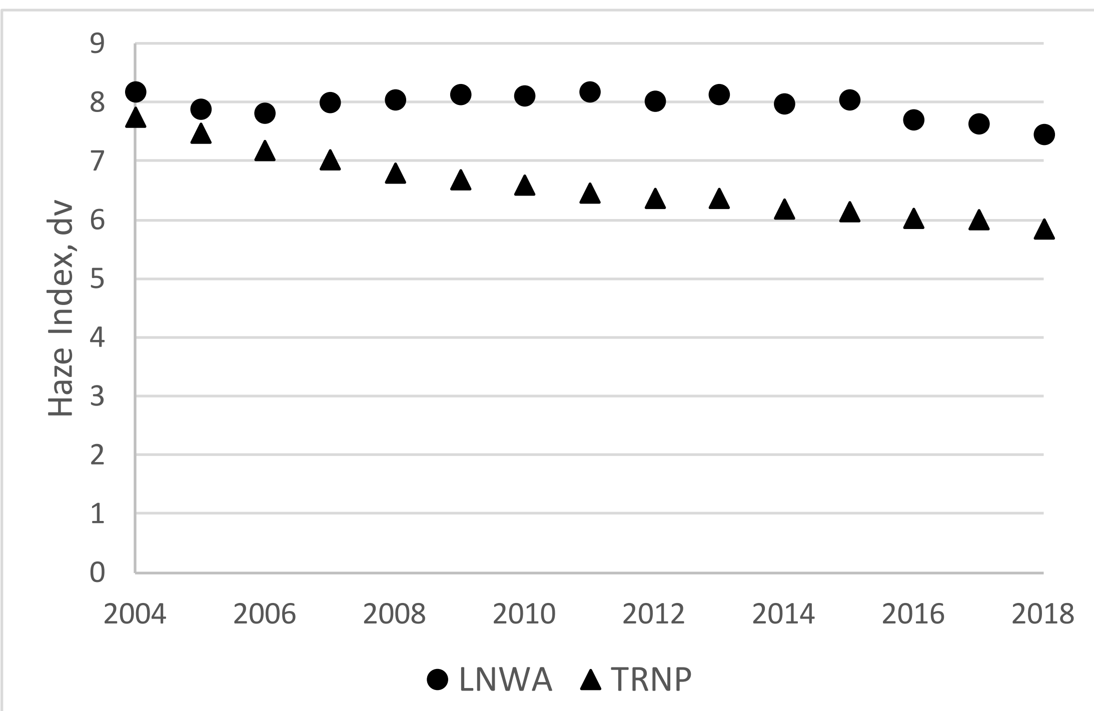



**Figure 5-4 Five-year rolling average of visibility conditions at IMPROVE monitoring sites in North Dakota on 20% best visibility days**

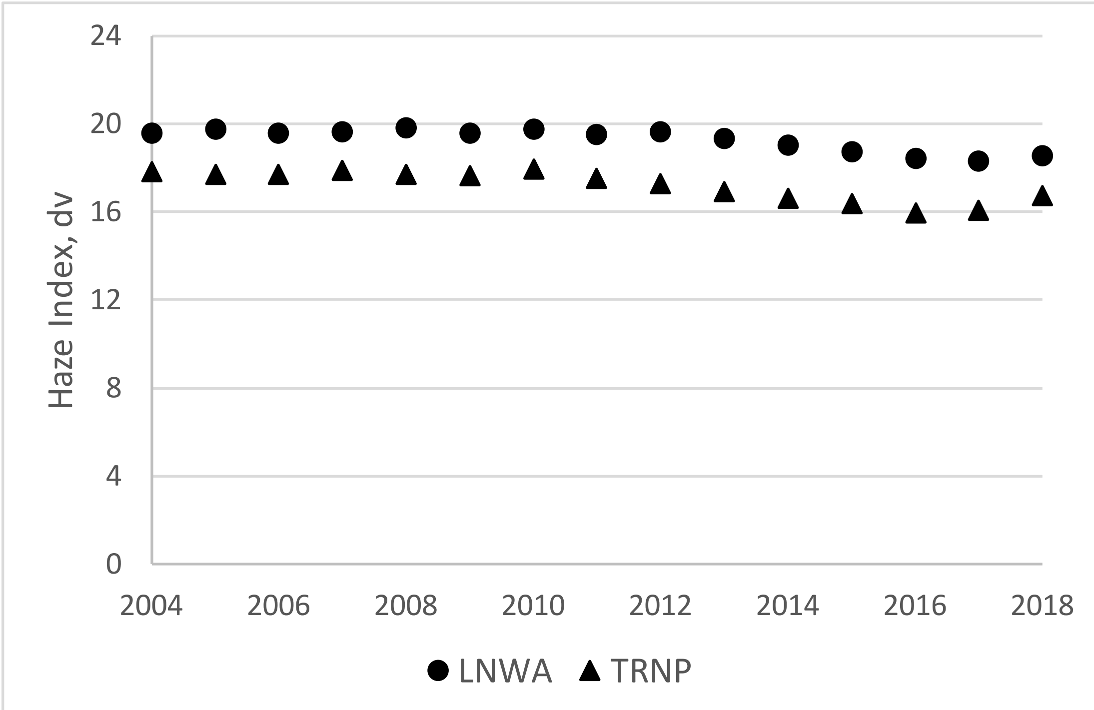



**Figure 5-5 Five-year rolling average of visibility conditions at IMPROVE monitoring sites in North Dakota on 20% worst visibility days**

# Chapter 6
# Coordination and Consultation

## 6.1 Agencies and People Consulted

No additional people or agencies beyond those identified in Chapter 5.0 of the BLM EA were consulted prior to and during the preparation of this Supplemental EA.

## 6.2 Preparers and Participants

Table 6-1 shows a list of the preparers of this EA and those who participated in the preparation of this EA from OSMRE.

**Table 6-1 List of Preparers**

| Organization | Name | Title/ Project Responsibility |
|---|---|---|
| OSMRE | Logan Sholar | Natural Resource Specialist/ Project Manager, internal scoping, review of EA |
| OSMRE | Erica Trent | Natural Resource Specialist/MPDD Coordinator |
| OSMRE | Roberta Martinez Hernandez | Technical Reviewer |

Table 6-2 shows a list of the preparers of this EA and those who participated in the preparation of this EA from the third-party consultants Barr Engineering Co.

**Table 6-2 Contractors**

| Organization | Name | Title/ Project Responsibility |
|---|---|---|
| Barr Engineering Co. | Nadine Czoschke, PhD | Senior Environmental Scientist/ EA author |
| Barr Engineering Co. | Rachael Shetka | Senior Environmental Specialist/Project Manager EA author |
| Barr Engineering Co. | Amar Patel | Air Quality Scientist/Emission Calculations |
| Barr Engineering Co. | Amanda Gravseth | Environmental Permitting and Compliance Engineer/Emission Calculations |
| Barr Engineering Co. | Cliff Twaroski | Vice President and Senior Environmental Scientist, EA author |
| Barr Engineering Co. | Sona Psarska | Environmental Scientist, EA author |

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# Appendix A
# Air Emissions Information

## Emission Factors for BNI Coal Emissions Calculations

### AP42, Chapter 13, Section 2.2 Unpaved Roads

Equation 1a

EF = k * (s/12)a * (W/3)b
where,
k, a, and b are empirical constants from AP 42 Section 13.2.2 Table 13.2.2-2
E = size-specific emission factor (lb/VMT)
s = surface material silt content (%) from AP 42 Section 13.2.2 Table 13.2.2-1
W = mean vehicle weight (tons)

### AP42, Section 13.2, Introduction to Fugitive Dust Sources, Table 13.2.2-1 and 13.2.2-2

| Constant | PM | $PM_{10}$ | $PM_{2.5}$ | Comment |
|---|---|---|---|---|
| s (%) | 8.4 | 8.4 | 8.4 | Western surface coal mining Haul road to/from pit |
| k (lb/VMT) | 4.9 | 1.5 | 0.15 | No Comment |
| a | 0.7 | 0.9 | 0.9 | No Comment |
| b | 0.45 | 0.45 | 0.45 | No Comment |

### AP42, Section 11.9 Western Surface Coal Mines, Table 11.9-1

| Operation | $PM_{15}$ | $PM_{10}$ | $PM_{2.5}$ | Units |
|---|---|---|---|---|
| Truck Loading | 0.01 | 0.01 | 0.00 | lb/ton |
| Bulldozing | 17.06 | 12.80 | 0.38 | lb/hr |
| Dragline | 0.02 | 0.01 | 0.00 | lb/cubic yard (assume 1.2 ton/cubic yd density) |
| Grading | 1.03 | 0.62 | 0.03 | lb/vmt |
| Active storage pile | 9.65 | 9.65 | 9.65 | lb/acre-hr (assume PM=PM10=PM2.5) |

### AP42, Section 11.9 Western Surface Coal Mines, Table 11.9-3 and Table 11.9-5

| Description | Value | Constant | Unit | Comment |
|---|---|---|---|---|
| Horizontal area | | A | ft2 | Blasting depth # 70 ft. Not for vertical face of a bench |
| Material moisture content | 17.8 | M | % | Coal loading |
| Material moisture content | 10.4 | M | % | Bulldozing coal |
| Material moisture content | 3.2 | M | % | Dragline |
| Material silt content | 8.4 | s | % | No Comment |
| Wind speed | 13.4 | u | mph | No Comment |
| Drop height | 28.1 | d | ft | No Comment |
| Mean vehicle speed | 4.5 | S | mph | Grading; value provided by client |

### AP42, Chapter 13, Section 3.3, Table 13.3-1 Emission Factors for Detonation of Explosives

| Composition | Explosive | CO | $NO_x$ | $SO_2$ | Unit |
|---|---|---|---|---|---|
| 4,5 Ammonium nitrate with 5.8-8% fuel oil | ANFO | 67 | 17 | 2 | lb/ton |

### Table C-1 and C-2 to Subpart C of 40 C.F.R. Part 98—Default High Heat Values for Various Types of Fuel

| Fuel type | HHV | Unit |
|---|---|---|
| Lignite | 14.21 | MMBtu/short ton |
| Distillate Fuel Oil No. 2 | 0.14 | MMBtu/gallon |
| Gasoline | 0.13 | MMBtu/gallon |

### Table C-1 and C-2 to Subpart C of 40 C.F.R. Part 98

### Default CO2, CH4, and N2O Emission Factors for Various Types of Fuel

| Fuel type | $CO_2$ | $CH_4$ | $N_2O$ | $CO_2e$ | Unit |
|---|---|---|---|---|---|
| Lignite | 97.72 | 1.10E-02 | 1.60E-03 | | kg/MMBtu |
| Lignite | 1.389 | 1.56E-04 | 2.27E-05 | 1.399 | metric ton/short ton |
| Distillate Fuel Oil No. 2 | 73.96 | 3.00E-03 | 6.00E-04 | | kg/MMBtu |
| Distillate Fuel Oil No. 2 | 0.010 | 4.14E-07 | 8.28E-08 | 0.010 | metric ton/gal |
| Gasoline | 71.30 | 3.00E-03 | 6.00E-04 | | kg/MMBtu |
| Gasoline | 0.009 | 3.75E-07 | 7.50E-08 | 0.009 | metric ton/gal |

### Global Warming Potential - AR5

| Greenhouse gas | GWP |
|---|---|
| $CO_2$ | 1 |
| $CH_4$ | 28 |
| $N_2O$ | 265 |

| Horsepower | Kilowatt | Fleet Vehicle Types | Model | Emission Standard | HC Exhaust (g/kw-hr)[a] | NOx Exhaust (g/kw-hr)[a] | NMHC +NOX Exhaust (g/kw-hr)[a] | CO Exhaust (g/kw-hr)[a] | PM Exhaust (g/kw-hr)[a] | $SO_X$ lb/hp-hr[b] | CO2 lb/hp-hr[b] | TOC Exhaust lb/hp-hr[b] | Black carbon[c] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 533 | 397 | M. grader | 24M | Tier 3 | n/a | n/a | 4.0 | 3.5 | 0.20 | 2.05E-03 | 1.15 | 2.47E-03 | 0.15 |
| 580 | 433 | track dozer | D6T-D10T | Tier 3 | n/a | n/a | 4.0 | 3.5 | 0.20 | 2.05E-03 | 1.15 | 2.47E-03 | 0.15 |
| 850 | 634 | track dozer | D11T | Tier 2 | n/a | n/a | 6.4 | 3.5 | 0.20 | 1.21E-05 | 1.16 | 7.05E-04 | 0.15 |
| 1791 | 1336 | haul trucks | 789C | Tier 2 | n/a | n/a | 6.4 | 3.5 | 0.20 | 1.21E-05 | 1.16 | 7.05E-04 | 0.15 |
| 297 | 221 | M. grader | 16M | Tier 3 | n/a | n/a | 4.0 | 3.5 | 0.20 | 2.05E-03 | 1.15 | 2.47E-03 | 0.15 |
| 1051 | 784 | scraper | 657G | Tier 3[d] | n/a | n/a | 6.4 | 3.5 | 0.20 | 1.21E-05 | 1.16 | 7.05E-04 | 0.15 |
| 945 | 705 | front end loader | 993K | Tier 1 | 1.3 | 9.2 | n/a | 11.4 | 0.54 | 1.21E-05 | 1.16 | 7.05E-04 | 0.405 |
| 801 | 597 | rt dozer & excavators & drill equipment | 854K | Tier 2 | n/a | n/a | 6.4 | 3.5 | 0.20 | 1.21E-05 | 1.16 | 7.05E-04 | 0.15 |
| 1969 | 1468 | Kress haul truck | 200C III | Tier 2 | n/a | n/a | 6.4 | 3.5 | 0.20 | 1.21E-05 | 1.16 | 7.05E-04 | 0.15 |
| 300 | 224 | rt dozer & excavators & drill equipment | DML HP 1450 ATLAS COPCO | Tier 3 | n/a | n/a | 4.0 | 3.5 | 0.20 | 2.05E-03 | 1.15 | 2.47E-03 | 0.15 |
| 404 | 301 | rt dozer & excavators & drill equipment | 349EL | Tier 3 | n/a | n/a | 4.0 | 3.5 | 0.20 | 2.05E-03 | 1.15 | 2.47E-03 | 0.15 |
| 29 | 22 | mobile sources | mobile sources | Tier 3[d] | n/a | n/a | 7.5 | 5.5 | 0.6 | 2.05E-03 | 1.15 | 2.47E-03 | 0.45 |
| 241 | 180 | light vehicle - gasoline | light vehicles | Tier 3 | n/a | n/a | 4.0 | 3.5 | 0.20 | 2.05E-03 | 1.15 | 2.47E-03 | 0.15 |

Note(s):
(a) Emission standards from https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf
(b) AP-42 Table 3.3-1 (under 600 hp) and Table 3.4-1 (over 600 hp)
(c) Clean Air Task Force, 2009; Table 5. Assumption that 75% of diesel particulate matter is black carbon
(d) Conservatively estimated as Tier 2 emission standards using data from https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

### Permitted Emission Units Emission Limits at BNI Coal

| Unit # | Description | Rate, ton/hr | Emission Limit, lb/hr PM |
|---|---|---|---|
| EU 1 | Center Coal Mine | 525 | N/A |

| Particle size range | Fraction |
|---|---|
| PM10 | 0.75 |
| PM2.5 | 0.03 |

AP-42 Table 11.9-01 most conservative fraction for coal

| NDM-102083 Extraction Plan | tons | Percent of Tract 1 NDM-102083 extractable coal | Percent of BNI Historical Annual Coal Mined |
|---|---|---|---|
| Total NDM-102083 extractable coal | 1,690,000 | | 39% |
| Year 1 | 96,000 | 6% | 2% |
| Year 2 | 109,000 | 7% | 3% |
| Year 3 | 264,000 | 16% | 6% |
| Year 4 | 251,000 | 15% | 6% |
| Year 5 | 510,000 | 31% | 12% |
| Year 6 | 318,000 | 20% | 7% |
| Year 7 | 76,000 | 5% | 2% |
| Total BNI average coal throughput | 4,319,590 | tons | |
| Maximum BNI coal throughput | 4,600,000 | tons | |

## Emissions Calculation Inputs for BNI Coal Fugitive Dust and Tailpipe Emissions

### Based on fuel usage and metered hours

| Vehicle Type | Distance Traveled | Unit | Average weight | Capacity | Unit | Model | PM EF | $PM_{10}$ EF | $PM_{2.5}$ EF | Unit |
|---|---|---|---|---|---|---|---|---|---|---|
| End dump loads | 135,631 | miles/yr | 518 | 190 | tons | 789C | 38.763 | 11.049 | 1.105 | lb/vmt |
| Scrapers | 7,698 | miles/yr | 79 | n/a | tons | 657G | 16.672 | 4.752 | 0.475 | lb/vmt |
| Kress trucks | 217,416 | miles/yr | 461 | 200 | tons | 200C III | 36.786 | 10.486 | 1.049 | lb/vmt |
| Light Vehicles (gasoline) | 900,000 | miles/yr | 5 | n/a | tons | Various | 4.804 | 1.369 | 0.137 | lb/vmt |
| Water trucks | 50,000 | miles/yr | 232 | n/a | tons | 777F | 27.010 | 7.699 | 0.770 | lb/vmt |
| Motor graders | 98,100 | miles/yr | 73 | n/a | tons | 16M, 24M | 16.043 | 4.573 | 0.457 | lb/vmt |
| Total | 1,408,845 | miles/yr | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

### Annual Fuel Usage, 2015-2019

| Year | Diesel Usage | Gasoline Usage | Unit | CO2 | CH4 | N2O | CO2e | Unit |
|---|---|---|---|---|---|---|---|---|
| 2015 | 3,021,045 | 58,241 | gallons | 31,353 | 1.27 | 0.25 | 31,456 | tons |
| 2016 | 2,936,829 | 69,718 | gallons | 30,596 | 1.24 | 0.25 | 30,697 | tons |
| 2017 | 3,082,423 | 55,410 | gallons | 31,955 | 1.30 | 0.26 | 32,060 | tons |
| 2018 | 3,110,065 | 79,597 | gallons | 32,452 | 1.32 | 0.26 | 32,559 | tons |
| 2019 | 3,000,304 | 66,903 | gallons | 31,219 | 1.27 | 0.25 | 31,321 | tons |
| Average | 3,030,133 | 65,974 | gallons | 31,515 | 1.28 | 0.26 | 31,619 | tons |

Note(s):
Annual VMT, diesel, and gasoline data provided by BNI Coal

## Blasting Emissions at BNI Coal

| ANFO | Amount | Unit |
|---|---|---|
| 2015 | 1,494,555.0 | lbs |
| 2016 | 1,230,488.0 | lbs |
| 2017 | 1,054,680.0 | lbs |
| 2018 | 501,722.0 | lbs |
| 2019 | 314,334.0 | lbs |
| Total | 4,595,779.0 | lbs |

| Year | CO[a] | $NO_X$[a] | $SO_2$[a] | Unit |
|---|---|---|---|---|
| 2015 | 25.0 | 6.4 | 0.75 | tpy |
| 2016 | 20.6 | 5.2 | 0.62 | tpy |
| 2017 | 17.7 | 4.5 | 0.53 | tpy |
| 2018 | 8.4 | 2.1 | 0.25 | tpy |
| 2019 | 5.3 | 1.3 | 0.16 | tpy |
| Average | 15.4 | 3.9 | 0.46 | tpy |

Note(s):
Annual ANFO data provided by BNI Coal
(a) Calculation methodology for CO, NOx, and SO2 follows AP42, Chapter 13, Section 3.3, which provides an emission factor for pounds of pollutants per ton of ANFO combusted.

## Estimated Surface Methane Emissions from Mining and Post-Mining Operations at BNI Coal

| Proposed Action Activity | Total Coal Production (tons) | Proposed Action Activity (kg/ton) | Estimated Total Methane Emissions from Mining and Post-Mining[a] (kg) | Estimated Total Methane Emissions from Mining and Post-Mining[a] (Metric Tons) | Estimated Total Methane Emissions from Mining and Post-Mining[a] (Metric Tons of $CO_{2e}$) |
|---|---|---|---|---|---|
| Mining | 4,319,590 | 0.1608 | 694,590 | 695 | 19,449 |
| Post-Mining | 4,319,590 | 0.0345 | 149,026 | 149 | 4,173 |
| Total | 4,319,590 | --- | 843,616 | 844 | 23,621 |

Note(s):
(a) US EPA 2016 Annexes to the Inventory of the U.S. GHG Emissions and Sinks. Annex 3.4 Methodology for Estimated CH4 Emission from Coal Mining, and Annex 6.5 Constants, Units, and Conversions.
Post-Mining emissions include coal handling, storage, and transportation emissions.

## BNI Coal Total Mine Historical Emissions

### Whole Mine Direct Fleet Emissions, Average of 2015-2019, tons

| Equipment | $NO_x$ | $SO_X$ | CO | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|---|---|---|
| Hydraulic Shovels | 2 | 0.6 | 2 | 0.1 | 0.1 |
| Rubber Tire Dozers | 99 | 0.1 | 54 | 3.1 | 3.1 |
| Track Dozers (D6-D10T) | 19 | 5.9 | 17 | 1.0 | 1.0 |
| Track Dozers (D11T) | 73 | 0.1 | 40 | 2.3 | 2.3 |
| F.E. Loaders | 169 | 0.1 | 196 | 9.3 | 9.3 |
| Motor Graders | 38 | 11.9 | 33 | 1.9 | 1.9 |
| Scrapers | 58 | 0.1 | 32 | 1.8 | 1.8 |
| Kress Coal Haulers | 124 | 0.1 | 68 | 3.9 | 3.9 |
| Haul Trucks | 239 | 0.3 | 131 | 7.5 | 7.5 |
| Total | 822 | 19.2 | 572 | 30.8 | 30.8 |

### Whole Mine Fugitive Emissions, average of 2015-2019, tons

| Fugitive Sources | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|
| Road Emissions | 1,119 | 112 |
| Truck Loading | 4.3 | 0.1 |
| Bull Dozing | 51 | 1 |
| Dragline | 5.0 | 0.1 |
| Grading | 9 | 0 |
| Active Storage Pile | 0.6 | 0.6 |
| Total | 1,188.9 | 114.7 |

**Average Emissions per Year Whole Mine, 2015-2019**

| Pollutant | Tailpipe emissions | Blasting | Fugitives | Total | Units |
|---|---|---|---|---|---|
| $NO_X$ | 991.2 | 3.9 | n/a | 995.2 | tons |
| $SO_X$ | 19.2 | 0.5 | n/a | 19.7 | tons |
| CO | 572.3 | 15.4 | n/a | 587.7 | tons |
| PM | 30.8 | n/a | 1,188.9 | 1,219.6 | tons |
| $PM_{10}$ | 30.8 | n/a | 1,188.9 | 1,219.6 | tons |
| $PM_{2.5}$ | 30.8 | n/a | 114.7 | 145.4 | tons |
| $CO_2$ | 31,515.0 | n/a | n/a | 31,515.0 | metric tons |
| $CH_4$ | 1.3 | n/a | 843.6 | 844.9 | metric tons |
| $N_2O$ | 0.3 | n/a | n/a | 0.3 | metric tons |
| $CO_2e$ | 31,618.6 | n/a | 23,621.2 | 55,239.8 | metric tons |
| Black carbon | 23.1 | n/a | n/a | 23.1 | tons |

| Approximate Months | Coal Source |
|---|---|
| 5 | NDM-102083 Coal |
| 7 | non-NDM-102083 Coal |

## Total Emissions, for the duration NDM-102083 mining, average of 2015-2019

| Pollutant | Tailpipe emissions | Blasting | Fugitives | Total |
|---|---|---|---|---|
| $NO_X$ | 387.8 | 1.5 | n/a | 389.3 |
| $SO_X$ | 7.5 | 0.2 | n/a | 7.7 |
| CO | 223.9 | 6.0 | n/a | 229.9 |
| $PM_{10}$ | 12.0 | n/a | 465.1 | 477.2 |
| $PM_{2.5}$ | 12.0 | n/a | 44.9 | 56.9 |
| Black carbon | 9.0 | n/a | n/a | 9.0 |

Note(s):
All emissions are in in US short tons unless otherwise noted.

## Whole Mine Direct GHG Emissions, metric tons

| Pollutant | Tailpipe emissions | Surface mining | Post-mining surface | Total |
|---|---|---|---|---|
| $CO_2$ | 31,515.0 | n/a | n/a | 31,515.0 |
| $CH_4$ | 1.3 | 694.6 | 149.0 | 844.9 |
| $N_2O$ | 0.3 | n/a | n/a | 0.3 |
| $CO_2e$ | 31,618.6 | 19,448.5 | 4,172.7 | 55,239.8 |

## NDM-102083 Direct Fleet Emissions, tons

| Equipment | $NO_x$ | $SO_X$ | CO | $PM_{2.5}$ |
|---|---|---|---|---|
| Hydraulic Shovels | 1 | 0.23 | 0.6 | 0.0 |
| Rubber Tire Dozers | 39 | 0.04 | 21.1 | 1.2 |
| Track Dozers (D6-D10T) | 7 | 2.33 | 6.5 | 0.4 |
| Track Dozers (D11T) | 29 | 0.03 | 15.7 | 0.9 |
| F.E. Loaders | 66 | 0.05 | 76.7 | 3.6 |
| Motor Graders | 15 | 4.66 | 13.1 | 0.7 |
| Scrapers | 23 | 0.03 | 12.4 | 0.7 |
| Kress Coal Haulers | 49 | 0.06 | 26.6 | 1.5 |
| Haul Trucks | 93 | 0.11 | 51.1 | 2.9 |
| Total | 322 | 7.5 | 224 | 12 |

## NDM-102083 Fugitive Emissions, tons

| Fugitive Sources | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|
| Road Emissions | 437.9 | 43.8 |
| Truck Loading | 1.7 | 0.04 |
| Bull Dozing | 19.8 | 0.6 |
| Dragline | 1.9 | 0.04 |
| Grading | 3.6 | 0.2 |
| Active Storage Pile | 0.2 | 0.2 |
| Total | 465.1 | 44.9 |

## Total Direct Emissions During Each Year of Mine Plan for NDM-102083 Coal

| Pollutant | From NDM-102083 coal, Year 1 | From NDM-102083 coal, Year 2 | From NDM-102083 coal, Year 3 | From NDM-102083 coal, Year 4 | From NDM-102083 coal, Year 5 | From NDM-102083 coal, Year 6 | From NDM-102083 coal, Year 7 | Average Historical BNI Coal | Units |
|---|---|---|---|---|---|---|---|---|---|
| NOx | 23 | 26 | 63 | 60 | 122 | 76 | 18 | 995 | tons |
| $SO_X$ | 0.5 | 0.5 | 1.3 | 1.2 | 2.4 | 1.5 | 0.4 | 19.7 | tons |
| CO | 14 | 15 | 37 | 36 | 72 | 45 | 11 | 588 | tons |
| PM | 28 | 32 | 78 | 74 | 150 | 93 | 22 | 1,220 | tons |
| $PM_{10}$ | 28 | 32 | 78 | 74 | 150 | 93 | 22 | 1,220 | tons |
| $PM_{2.5}$ | 3.4 | 3.8 | 9.3 | 8.8 | 17.9 | 11.1 | 2.7 | 145.4 | tons |
| $CO_2$ | 729 | 828 | 2,004 | 1,906 | 3,872 | 2,414 | 577 | 31,515 | metric tons |
| $CH_4$ | 20 | 22 | 54 | 51 | 104 | 65 | 15 | 845 | metric tons |
| $N_2O$ | 0.01 | 0.01 | 0.02 | 0.02 | 0.03 | 0.02 | 0.00 | 0.26 | metric tons |
| $CO_2e$ | 1,278 | 1,451 | 3,513 | 3,340 | 6,787 | 4,232 | 1,011 | 55,240 | metric tons |
| Black carbon | 0.5 | 0.6 | 1.5 | 1.4 | 2.8 | 1.8 | 0.4 | 23.1 | tons |

### Total Direct Emissions for the Seven Year Mine Plan for NDM-102083

| Pollutant | From NDM-102083 coal, tons [A] | From non-NDM-102083 coal, tons [B] | Total BNI Coal , tons [A+B] | Average Historical BNI Coal, tons | Change in total BNI Coal emissions, tons |
|---|---|---|---|---|---|
| $NO_X$ | 389 | 6,577 | 6,966 | 6,966 | 0 |
| $SO_X$ | 7.7 | 130 | 138 | 138 | 0 |
| CO | 230 | 3,884 | 4,114 | 4,114 | 0 |
| PM | 477 | 8,060 | 8,538 | 8,538 | 0 |
| $PM_{10}$ | 477 | 8,060 | 8,538 | 8,538 | 0 |
| $PM_{2.5}$ | 56.9 | 961 | 1,018 | 1,018 | 0 |
| $CO_2$ | 12,330 | 208,275 | 220,605 | 220,605 | 0 |
| $CH_4$ | 331 | 5,584 | 5,914 | 5,914 | 0 |
| $N_2O$ | 0.1 | 1.7 | 1.8 | 1.8 | 0.0 |
| $CO_2e$ | 21,612 | 365,067 | 386,679 | 386,679 | 0 |
| Black carbon | 9.0 | 153 | 162 | 162 | 0 |

### Total Direct GHG Emissions for the Seven Year Mine Plan for NDM-102083, metric tons

| Pollutant | Tailpipe emissions | Surface mining | Post-mining surface | Total |
|---|---|---|---|---|
| $CO_2$ | 12,330 | n/a | n/a | 12,330 |
| $CH_4$ | 0.5 | 272 | 58 | 331 |
| $N_2O$ | 0.1 | n/a | n/a | 0.1 |
| $CO_2e$ | 12,370 | 7,609 | 1,633 | 21,612 |

## BNI Coal Total Mine Maximum Emissions

### Whole Mine Maximum Annual Direct Fleet Emissions, tons

| Equipment | $NO_x$ | $SO_X$ | CO | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|---|---|---|
| Hydraulic Shovels | 2 | 0.6 | 2 | 0.1 | 0.1 |
| Rubber Tire Dozers | 105 | 0.1 | 57 | 3.3 | 3.3 |
| Track Dozers (D6-D10T) | 20 | 6.3 | 18 | 1.0 | 1.0 |
| Track Dozers (D11T) | 78 | 0.1 | 43 | 2.4 | 2.4 |
| F.E. Loaders | 180 | 0.1 | 209 | 9.9 | 9.9 |
| Motor Graders | 41 | 12.7 | 36 | 2.0 | 2.0 |
| Scrapers | 62 | 0.1 | 34 | 1.9 | 1.9 |
| Kress Coal Haulers | 132 | 0.2 | 72 | 4.1 | 4.1 |
| Haul Trucks | 254 | 0.3 | 139 | 7.9 | 7.9 |
| Total | 875 | 20.5 | 609 | 32.8 | 32.8 |

### Whole Mine Maximum Annual Fugitive Emissions, tons

| Fugitive Sources | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|
| Road Emissions | 1,192 | 119 |
| Truck Loading | 4.6 | 0.1 |
| Bull Dozing | 54 | 2 |
| Dragline | 5.3 | 0.1 |
| Grading | 10 | 1 |
| Active Storage Pile | 0.6 | 0.6 |
| Total | 1,266.0 | 122.1 |

### Maximum Annual Whole Mine Emissions

| Pollutant | Tailpipe emissions | Blasting | Fugitives | Total | Units |
|---|---|---|---|---|---|
| $NO_X$ | 1,055.6 | 4.2 | n/a | 1,059.8 | tons |
| $SO_X$ | 20.5 | 0.5 | n/a | 21.0 | tons |
| CO | 609.4 | 16.4 | n/a | 625.8 | tons |
| PM | 32.8 | n/a | 1,266.0 | 1,298.8 | tons |
| $PM_{10}$ | 32.8 | n/a | 1,266.0 | 1,298.8 | tons |
| $PM_{2.5}$ | 32.8 | n/a | 122.1 | 154.9 | tons |
| $CO_2$ | 33,560.8 | n/a | n/a | 33,560.8 | metric tons |
| $CH_4$ | 1.4 | n/a | 898.4 | 899.7 | metric tons |
| $N_2O$ | 0.3 | n/a | n/a | 0.3 | metric tons |
| $CO_2e$ | 33,671.2 | n/a | 25,154.6 | 58,825.8 | metric tons |
| Black carbon | 24.6 | n/a | n/a | 24.6 | tons |

### Whole Mine Maximum Annual GHG Emissions, metric tons

| Pollutant | Tailpipe emissions | Surface mining | Post-mining surface | Total |
|---|---|---|---|---|
| $CO_2$ | 33,560.8 | n/a | n/a | 33,560.8 |
| $CH_4$ | 1.4 | 739.7 | 158.7 | 899.7 |
| $N_2O$ | 0.3 | n/a | n/a | 0.3 |
| $CO_2e$ | 33,671.2 | 20,711.0 | 4,443.6 | 58,825.8 |

## Indirect Emissions from Combustion of BNI Coal

### Annual Indirect GHG Emissions based on coal combusted at Milton R. Young Station, 2015-2019

| Year | Coal Combusted | Unit | $CO_2$ | $CH_4$ | $N_2O$ | $CO_2e$ | Unit |
|---|---|---|---|---|---|---|---|
| 2015 | 4,319,590 | tons | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |
| 2016 | 4,319,590 | tons | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |
| 2017 | 4,319,590 | tons | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |
| 2018 | 4,342,650 | tons | 6,030,209 | 679 | 99 | 6,075,380 | metric tons |
| 2019 | 4,296,530 | tons | 5,966,167 | 672 | 98 | 6,010,858 | metric tons |
| Average | 4,319,590 | tons | 5,998,188 | 675 | 98 | 6,043,119 | metric tons |

### Annual Total Indirect Emissions based on coal combusted at Milton R. Young Station, 2015-2019

| Year | Coal Combusted | Unit | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | NOx | CO | TOC | Ammonia | Unit |
|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 4,319,590 | tons | 338 | 36 | 2,735 | 9,008 | 146 | 148 | 12 | tons |
| 2016 | 4,319,590 | tons | 252 | 28 | 2,638 | 8,140 | 39 | 135 | 14 | tons |
| 2017 | 4,319,590 | tons | 296 | 29 | 3,412 | 9,971 | 166 | 162 | 12 | tons |
| 2018 | 4,342,650 | tons | 334 | 33 | 2,776 | 9,259 | 191 | 151 | 12 | tons |
| 2019 | 4,296,530 | tons | 279 | 33 | 2,658 | 8,563 | 189 | 149 | 13 | tons |
| Average | 4,319,590 | tons | 300 | 32 | 2,844 | 8,988 | 146 | 149 | 13 | tons |

| Year | Coal Combusted | Unit | Hg | Total Metals | Total HAPs and VOCs | HCl | HF | Unit |
|---|---|---|---|---|---|---|---|---|
| 2015 | 4,319,590 | tons | 0.09 | | | 21.10 | 21.10 | tons |
| 2016 | 4,319,590 | tons | 0.08 | | | 19.22 | 19.22 | tons |
| 2017 | 4,319,590 | tons | 0.10 | 1.23 | 0.02 | 23.20 | 23.20 | tons |
| 2018 | 4,342,650 | tons | 0.09 | | | 21.50 | 21.50 | tons |
| 2019 | 4,296,530 | tons | 0.09 | | | 21.27 | 21.27 | tons |
| Average | 4,319,590 | tons | 0.089 | 1.233 | 0.019 | 21.26 | 21.26 | tons |

## Annual NDM-102083 Coal combusted at Milton R. Young Station Indirect Emissions, over life of project

| Year | Coal Combusted | Unit | $PM_{10}$ | $PM_{2.5}$ | $SO_2$ | $NO_x$ | CO | VOC[a] | Ammonia | Unit |
|---|---|---|---|---|---|---|---|---|---|---|
| n/a | 1,690,000 | tons | 117 | 12 | 1,113 | 3,517 | 57 | 58 | 5 | tons |

Note(s):
(a) Assumes TOC=VOC

| Year | Coal Combusted | Unit | Hg | Total Metals | Total HAPs and VOCs | HCl | HF | Unit |
|---|---|---|---|---|---|---|---|---|
| n/a | 1,690,000 | tons | 0.03 | 0.48 | 0.01 | 8.32 | 8.32 | tons |

| Year | Coal Combusted | Unit | $CO_2$ | $CH_4$ | $N_2O$ | CO2e | Unit |
|---|---|---|---|---|---|---|---|
| n/a | 1,690,000 | tons | 2,346,736 | 264 | 38 | 2,364,315 | metric tons |

**NDM-102083 Emissions Transposed**

| | Total NDM-102083 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Unit |
|---|---|---|---|---|---|---|---|---|---|
| Coal Combusted | 1,690,000 | 96,000 | 109,000 | 264,000 | 251,000 | 510,000 | 318,000 | 76,000 | tons |
| $PM_{10}$ | 117 | 6.7 | 7.6 | 18.3 | 17.4 | 35.4 | 22.1 | 5.3 | tons |
| $PM_{2.5}$ | 12 | 0.7 | 0.8 | 1.9 | 1.8 | 3.8 | 2.3 | 0.6 | tons |
| $SO_2$ | 1,113 | 63.2 | 71.8 | 173.8 | 165.3 | 335.8 | 209.4 | 50.0 | tons |
| $NO_x$ | 3,517 | 199.8 | 226.8 | 549.3 | 522.3 | 1061.2 | 661.7 | 158.1 | tons |
| CO | 57 | 3.2 | 3.7 | 8.9 | 8.5 | 17.2 | 10.8 | 2.6 | tons |
| VOC* | 58 | 3.3 | 3.8 | 9.1 | 8.6 | 17.6 | 11.0 | 2.6 | tons |
| Ammonia | 5 | 0.3 | 0.3 | 0.8 | 0.7 | 1.5 | 0.9 | 0.2 | tons |
| Mercury | 69.68 | 4.0 | 4.5 | 10.9 | 10.3 | 21.0 | 13.1 | 3.1 | lbs |
| Total Metals | 964.41 | 54.8 | 62.2 | 150.7 | 143.2 | 291.0 | 181.5 | 43.4 | lbs |
| Total HAPs and VOCs | 15.18 | 0.9 | 1.0 | 2.4 | 2.3 | 4.6 | 2.9 | 0.7 | lbs |
| HCl | 8.3 | 0.5 | 0.5 | 1.3 | 1.2 | 2.5 | 1.6 | 0.4 | tons |
| HF | 8.3 | 0.5 | 0.5 | 1.3 | 1.2 | 2.5 | 1.6 | 0.4 | tons |
| $CO_2$ | 2,346,736 | 133,306 | 151,358 | 366,591 | 348,539 | 708,187 | 441,575 | 105,534 | metric tons |
| $CH_4$ | 264 | 15.0 | 17.0 | 41.3 | 39.2 | 79.7 | 49.7 | 11.9 | metric tons |
| $N_2O$ | 38 | 2.2 | 2.5 | 6.0 | 5.7 | 11.6 | 7.2 | 1.7 | metric tons |
| $CO_2e$ | 2,364,315 | 134,304 | 152,491 | 369,337 | 351,150 | 713,491 | 444,883 | 106,324 | metric tons |

## Comparison of Direct and Indirect to North Dakota and US Emissions

| All emissions in tons | 2019 ND, from State Tier 1 | NDM-102083 Direct, Year 5 | NDM-102083 Indirect, Year 5 | NDM-102083, % (Direct+Indirect) | Anticipated % change to State Emissions from Proposed Action |
|---|---|---|---|---|---|
| **CO** | 318,993 | 72.2 | 17.24 | 0.03% | 0% |
| **$NO_x$** | 141,215 | 122.3 | 1,061 | 0.8% | 0% |
| **$PM_{10}$** | 365,267 | 149.9 | 35 | 0.05% | 0% |
| **$PM_{2.5}$** | 77,568 | 17.9 | 4 | 0.03% | 0% |
| **$SO_2$** | 101,563 | 2.4 | 336 | 0.3% | 0% |
| **VOC** | 437,010 | n/a | 18 | 0.004% | 0% |

Note(s):
North Dakota Emissions referenced from EPA State Tier 1 inventory;
https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data

| All emissions in MM tons | CO2e | % of ND | % of US | Black carbon[a] | % of ND | % of US |
|---|---|---|---|---|---|---|
| **North Dakota Total, 2018** | 41 | | | 0.003 | | |
| **US Total, 2018** | 5,904 | | | 5.5 | | |
| **"NDM-102083 Direct Emissions,** | | | | | | |
| **Year 5"** | 0.007 | 0.02% | 0.0001% | 2.84E-06 | 0.1% | 0.0001% |

Note(s):
ND data as presented in EPA's FLIGHT Tool (http://ghgdata.epa.gov/ghgp)
US Total in USEPA 2020 US Greenhouse Gas Inventory Chapter 2: Trends in Greenhouse Gas Emissions
(a) Clean Air Task Force, 2009; Table 5. Assumption that 75% of diesel particulate matter is black carbon