The Falkirk Mining Company

½ Section 10 Federal Coal Mining Plan

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Supplemental Environmental Assessment

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Appendix A Air Emissions Information

Acronyms

Acronym	Definition
AEIR	Annual Emission Inventory Reports
BLM	Bureau of Land Management
CAA	Clean Air Act
CATF	Clean Air Task Force
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
CWA	Clean Water Act
DOI	Department of the Interior
EA	Environmental Assessment
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EO	Executive Order
EPA	Environmental Protection Agency
g	Grams
GHG	Greenhouse gas
GRE	Great River Energy
GWP	Global Warming Potential
H_2SO_4	Sulfuric acid
HAP	Hazardous Air Pollutant
HCl	Hydrogen chloride
HF	Hydrogen fluoride
Hg	Mercury
IPCC	Intergovernmental Panel on Climate Change
lb	Pounds
$\mu g/m^3$	Microgram per meter squared
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MLA	Mineral Leasing Act
MM	Million
MMTPY	Million tons per year
MPDD	Mining plan decision document
MW	Megawatt
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
ND	North Dakota
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act

Acronym	**Definition**
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
NPS	National Park Service
NSR	New Source Review
O_3	Ozone
OSMRE	Office of Surface Mining Reclamation and Enforcement
PAP	Permit Application Package
Pb	Lead
PM	Particulate matter
PM_{10}	Particulate matter less than 10 um in diameter
$PM_{2.5}$	Particulate matter less than 2.5 um in diameter
ppb	Parts per billion
ppm	Parts per million
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
SCC	Social cost of carbon
Se	Selenium
SF_6	Sulfurhexafluoride
SMCRA	Surface Mining Control and Reclamation Act
SO_2	Sulfur dioxide
SO_x	Sulfur oxides
TOC	Total Organic Carbon
TPY	Tons per year
TRI	Toxics Release Inventory
TRNP	Theodore Roosevelt National Park
US	United States
USC	United States Code
VOC	Volatile organic carbon

Chapter 1
Introduction

1.1 Introduction

The Falkirk Mining Company, operator of the Falkirk Mine in North Dakota, submitted a permit application package (PAP) to the North Dakota Public Service Commission (PSC) on November 9, 2017, to add the federal coal included in ½ Section 10. Please refer to *Figure 1 Location of Falkirk Mine* for the location of ½ Section 10. 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 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. The OSMRE is required to evaluate the PAP before Falkirk Mine may conduct mining and reclamation operations to develop the ½ Section 10. OSMRE is the agency responsible for making a recommendation to the United States Department of the Interior Assistant Secretary for Land and Minerals Management (ASLM) to approve, disapprove, or approve with conditions the proposed mining plan.

The Bureau of Land Management (BLM) North Dakota Field Office completed an Environmental Assessment (EA) in March 2017 that analyzed the environmental impacts of a federal coal lease proposed by The Falkirk Mining Company (Falkirk) located in the east ½ of Section 10, Township 146 North, Range 82 West, McLean County, North Dakota (refer to *Figure 1 Location of Falkirk Mine*). The United States (US) Department of the Interior (DOI), Office of Surface Mining Reclamation and Enforcement (OSMRE), Western Region Office and North Dakota Public Service Commission (PSC) cooperated in the preparation of the EA (BLM, 2017) (BLM, 2017).

As a federal agency, OSMRE is subject to the National Environmental Policy Act of 1969 (NEPA), and therefore must conduct an environmental review, in 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 the ASLM regarding the mining plan. The OSMRE has prepared this supplemental environmental assessment (EA), based on new information provided by the Operator to further assess potential air quality impacts associated with the issuance of the federal coal lease. The applicable analysis regarding the affected environment, environmental impacts and mitigation, and cumulative effects for the following elements are addressed, if determined necessary, in the BLM EA and are incorporated by reference[1] and are not discussed further in this Supplemental EA in accordance with 40 CFR 46.135:

- Areas of Critical Environmental Concern
- Cultural or Historical Values
- Economics
- Environmental Justice
- Floodplains
- General Vegetation
- General Wildlife
- Geology and Minerals
- Invasive, Nonnative Species
- Noise and Vibration
- Paleontology
- Prime or Unique Farmland
- Range
- Soils
- Threatened and Endangered Species
- Topography
- Transportation and Traffic
- Visual Resources Management
- Wastes, Hazardous or Solids
- Water Resources
- Wetland/Riparian
- Wild and Scenic Rivers
- Wilderness

The Supplemental EA review has been conducted in accordance with NEPA as amended and the President's Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 Code of Federal Regulations [Code of Federal Regulations (CFR)] 1500-1508); DOI regulations for implementation of NEPA (43 CFR 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* (OSMRE 1989).

The 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 CFR 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

[1] The BLM EA is available on their e-planning website at: https://eplanning.blm.gov/epl-front-office/projects/nepa/67410/105731/129311/DOI-BLM-MT-C030-2016-0020-EA.pdf

prepare a “Finding of No Significant Impact” to document this finding, and, accordingly, would not prepare an EIS.

The BLM Montana State Office is a cooperating agency in the preparation of this supplemental EA.

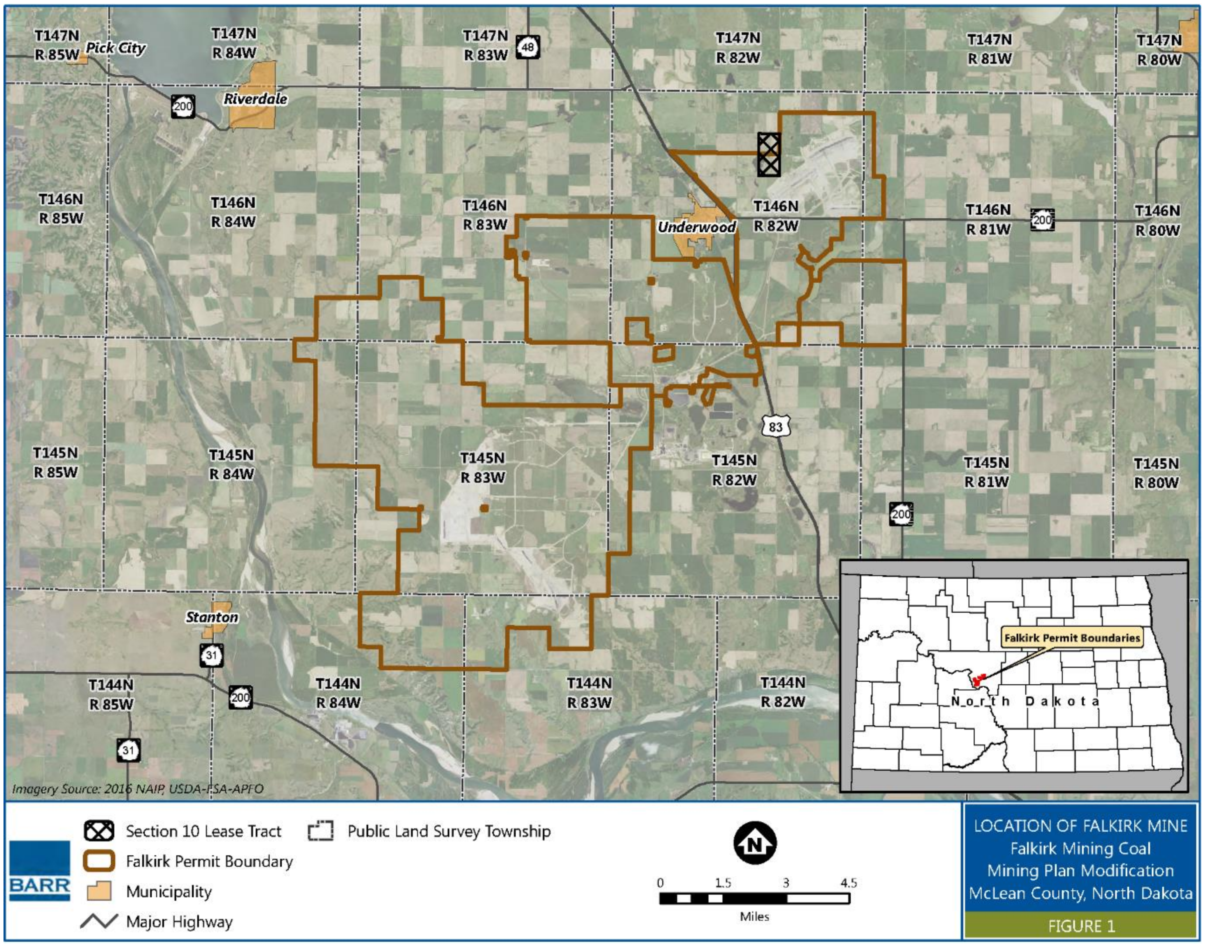

Figure 1 Location of Falkirk Mine

1.2 Background

The Falkirk Mine is located near Underwood, North Dakota. It was first incorporated in 1974, with initial construction starting in 1977, and coal production starting in 1978. Currently, the mine produces approximately 8.0 - 8.5 million tons of coal per year. Coal produced at the Falkirk Mine is transported from the pit in bottom-dump haul trucks to the truck dump/crushing facility. From that location, the coal is conveyed on a 5,300-foot-long conveyor to the Great River Energy’s Coal Creek Station, which is located approximately 6 miles south of Underwood, North Dakota. Coal Creek Station generates 1,200 megawatts (MW) (2 - 600 Megawatt Units) of power, which is transmitted to 28 power cooperatives that serve approximately two-thirds of rural Minnesota (BLM, 2017).

The proposed Section 10 lease tract, which encompasses the east ½ of Section 10, is part of the Falkirk Mine's current and extended Mining Plan with the south ½ of the Section 10 lease tract already permitted through the PSC for mining activities. The BLM held a competitive lease on October 17, 2017, which was awarded to Falkirk Mining; the effective date the lease was issued is January 1, 2018. The southeast ¼ of Section 10 (approximately 160 acres), NDM-107039 lease tract, is contained within the Falkirk Mine's permit, Permit No. NAFK-8405, issued by the North Dakota Public Service Commission (PSC) for mining activities; however, no actual mining of the federal coal tract can occur until the mining plan is approved by the ASLM. Revision 37 to Permit NAFK-8405, submitted to the North Dakota PSC on November 9, 2017, incorporates plans for mining the south-east ¼ of Section 10 NDM-107039 lease tract. The Falkirk Mine submitted a mining plan modification application, revision 38 to Permit NAFK-8405, to the North Dakota PSC on January 18, 2018 that adds 1680 acres to Permit NAFK-8405 including mining activities in the north-east ¼ of Section 10 (approximately 160 acres), NDM-107039 lease tract. ASLM approval of the mining plan and mining plan modification would authorize mining of 2.2 million tons of federal coal at the Falkirk Mine. Currently, the mine produces approximately 8.0 to 8.5 million tons of coal per year. The Section 10 lease tract has approximately 4.41 million tons of private and federal recoverable coal, of which 50%, or approximately 2.2 million tons, is federal ownership coal. Leasing and mining private and federal coal reserves within the Section 10 lease tract would contribute approximately seven months-worth of average production at the Falkirk Mine (BLM, 2017). Because the coal in the mineral rights of the Section 10 lease tract are undivided, the recovery of the private and federal coal would both occur with the approval of the mining plan. Thus, the impacts of the entire Section 10 lease tract of 4.41 million tons of coal is assessed in this Supplemental EA.

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 (NHPA);
- National Environmental Policy Act of 1969 (NEPA);
- Clean Air Act of 1970 (CAA);
- Clean Water Act of 1972 (CWA);
- Endangered Species Act of 1973 (ESA);
- 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 the MLA and SMCRA under regulations at CFR Title 30 - Mineral Resources, Chapter VII - OSMRE, Department of the Interior, Subchapters A-T, Parts 700-955.

The SMCRA provides the OSMRE primary responsibility for administering programs that regulate surface coal mining operations in the United States. Pursuant to Section 503 of SMCRA, 30 U.S.C. 1253, the North Dakota PSC developed, and the Secretary of the Interior approved, North Dakota's permanent regulatory program authorizing the 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, the North Dakota PSC entered into a cooperative agreement with the Secretary of the Interior authorizing the 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 Resource Recovery and Protection Plan and State Mining Permit application, to OSMRE and the North Dakota 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 North Dakota PSC issues a permit to the applicant to conduct coal-mining operations.

Once the State's findings and recommendations are received, OSMRE will prepare a mining plan decision document (MPDD) in support of its recommendation to the Assistant Secretary for Land and Minerals Management (ASLM), who will decide whether or not to approve the mining plan and whether or not additional conditions are needed. Pursuant to 30 CFR 746.13, the OSMRE's recommendation shall be based on:

- The PAP 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 the BLM with respect to the R2P2, federal lease requirements, and the MLA;
- Findings and recommendations of the North Dakota PSC with respect to the permit application and the state program; and
- The findings and recommendations of the OSMRE regarding additional requirements of 30 CFR 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 the Mineral Leasing Act of 1920 (MLA) and the SMCRA, which requires the evaluation of Falkirk Mine's PAP before they may conduct mining and reclamation operations to develop ½ Section 10 under 30 CFR Part 746: 30, United States Code (USC)/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 the MLA, the ASLM will decide whether the mining plan is approved, disapproved, or approved with conditions. If the ASLM approves this action, operations would be extended at the Falkirk Mine for up to an additional seven months. The need for the action is to allow Falkirk Mine the opportunity to exercise its valid rights granted for ½ Section 10 (Permit No. NAFK-8405) to extract coal from its federal lease issued by the BLM pursuant to the MLA.

1.5 Outreach and Issues Identification

OSMRE developed a project website, which provided additional notice, information, and comment opportunities: https://www.wrcc.osmre.gov/initiatives/falkirkMine.shtm. The website was activated on February 9, 2018, and is updated periodically as additional information becomes available.

OSMRE released the supplemental EA and unsigned FONSI on February 9, 2018 for a 30-day public comment period. OSMRE notified the public of this comment period through a newspaper notice published in the McLean County Independent and Central McLean News-Journal, mailed public outreach letters, as well as mailed tribal consultation letters to 18 tribal leaders. The public comment period ended on March 12, 2018. OSMRE received two comment letters during the comment period. OSMRE received a comment letter from the Bureau of Indian Affairs indicating they have “no environmental objections to the action as long as the project complies with all pertinent laws and regulations”. OSMRE also received a comment letter from the State of North Dakota PSC requesting correction to the dates of the mining plan modification applications to the North Dakota PSC. These corrections have been made in the EA and FONSI.

Chapter 2
Proposed Action and Alternatives

2.1 Introduction

This chapter incorporates Chapter 2.0 of the BLM EA by reference[2] and only provides supplemental information regarding air quality where relevant to the supplemental 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 alternatives considered but eliminated from detailed analysis, 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

The southeast ¼ of Section 10 (approximately 160 acres), NDM-107039 lease tract, is contained within the Falkirk Mine's permit, Permit No. NAFK-8405, issued by the North Dakota Public Service Commission (PSC) for mining activities; however, no actual mining of the federal coal tract can occur until the mining plan is approved by the ASLM. Revision 37 to Permit NAFK-8405, submitted to the North Dakota PSC on November 9, 2017, incorporates plans for mining the south-east ¼ of Section 10 NDM-107039 lease tract. The Falkirk Mine submitted a mining plan modification application, revision 38 to Permit NAFK-8405, to the North Dakota PSC on January 18, 2018 that adds 1680 acres to Permit NAFK-8405 including mining activities in the north-east ¼ of Section 10 (approximately 160 acres), NDM-107039 lease tract. The Proposed Action is for the OSMRE to submit a mining plan decision document making a recommendation to the Department of the Interior ASLM to approve the mining plan decision document. The modified mining plan includes mining coal within both the southeast ¼ and northeast ¼ of Section 10. The approved mining plan would authorize the mining, at the Falkirk Mine, of 4.41 million tons of coal, of which 2.2 million tons are federal coal in the Section 10 lease tract (BLM, 2017).

2.1.2 No Action

Under the No Action alternative, the OSMRE would not recommend approval of the mining plan decision document to ASLM. Without ASLM approval, ND PSC's permit would revert to the previous permit. Under the previous permit, the Federal coal reserves in the Section 10 Federal Coal Lease Tract would not be recovered and mining would continue until available coal reserves are mined out.

[2] The BLM EA is available on their eplanning website at: https://eplanning.blm.gov/epl-front-office/projects/nepa/67410/105731/129311/DOI-BLM-MT-C030-2016-0020-EA.pdf

2.1.3 Air Quality

Falkirk operates under synthetic minor source air permit number O79002 (NDAC 33-15-14-03.1.e) from the Environmental Health Section of the North Dakota Department of Health. As a synthetic minor source, Falkirk has taken production limits of 20 million tons per year at the primary crusher and conveyor, 34 million tons per year at the secondary crusher and conveyor, and 14 million tons per year at the cable belt conveyor system.

In accordance with its air permit, among other standards, Falkirk is required to comply with fugitive dust controls that include the following (NDDH, 2016):

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 onsite 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 Falkirk in both the Proposed Action and the No Action.

Chapter 3
Affected Environment

3.1 Introduction

This chapter describes the existing condition of resources that could be affected by implementation of the alternatives described in Chapter 2, as they relate to the Mining Plan Decision Document for Falkirk Mine. This chapter incorporates Chapter 3.0 of the BLM EA by reference[3] and only provides supplemental information regarding air quality and climate change where relevant to the supplemental analysis presented in this document.

3.2 Air Quality and Climate Change

3.2.1 Criteria Pollutants National Ambient Air Quality Standards

The Clean Air Act (CAA) requires the EPA 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.). EPA 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), see *Table 1 NAAQS Standard and Monitored Concentrations at Hanover*. Nitrogen oxides (NO_x) and volatile organic compounds (VOCs) contribute to ozone formation in the atmosphere and are regulated through equipment standards and emissions limits.

Air quality for any area is generally influenced by the types and quantities of air pollutant emissions released from natural and man-made sources within and upwind of the area. Additionally, the local topography, or terrain (such as mountains and valleys), and weather (such as wind, temperature, air turbulence and pressure, humidity, etc.) will have a direct effect on the how pollutants form, react, disperse, or accumulate. Ambient air quality in the affected area is assessed by conducting monitoring for ground level air pollutant concentrations in an air shed and comparing to air quality standards established to protect human health and welfare.

Air sheds are also 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 under the Prevention of Significant Deterioration (PSD) regulations. 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. Falkirk Mine is located in a Class II area. There are currently no Class III areas defined in North Dakota.

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[3] The BLM EA is available on their eplanning website at: https://eplanning.blm.gov/epl-front-office/projects/nepa/67410/105731/129311/DOI-BLM-MT-C030-2016-0020-EA.pdf

When a designated air quality area in a state exceeds a NAAQS that area may be designated as a “nonattainment” area. Areas with levels of pollutants below the health-based standard are designated as “attainment” areas. To determine whether an area meets the NAAQS, air monitoring networks have been established and are used to measure ambient air quality and determine attainment status. In addition, the visibility in Class I areas must be monitored based on the Regional Haze Rule (Clean Air Act 169A and 169B, 40 C.F.R 51, subpart P).

There are four Class I Areas located in North Dakota: Theodore Roosevelt National Park – North Unit (McKenzie County), Theodore Roosevelt National Park – Elkhorn Ranch Unit (Billings County), Theodore Roosevelt National Park – South Unit (Billings County), and Lostwood National Wilderness Area (Burke County). The primary anthropogenic sources of visibility impairment in North Dakota Class I Areas include electric utility steam generating units, energy production and processing sources, agricultural production and processing sources, prescribed burning, and fugitive dust sources (NDDH, 2014). The Section 10 lease tract is not located within a North Dakota Class I Area. The nearest North Dakota Class I Area to the Section 10 lease tract is the Theodore Roosevelt National Park – North Unit (McKenzie County). This Class I Area is located more than 105 miles away, generally upwind of the Section 10 lease tract and is unlikely to impact visibility conditions in North Dakota Class I areas.

EPA has delegated responsibility for many provisions of the Clean Air Act to the State of North Dakota Department of Health (NDDH). The NDDH is responsible for monitoring the levels of criteria pollutants. The NDDH maintains and operates a network of ten Ambient Air Quality Monitoring (AAQM) sites. Nine of these sites are operated directly by NDDH and one additional site is operated in partnership with the National Park Service (NPS) in the Theodore Roosevelt National Park (TRNP-SU) at Painted Canyon. This monitor and the NDDH monitor in the north section of Theodore Roosevelt National Park (TRNP-NU) are both in Federal Class I areas. In addition, there are two monitors in Williams County that are operated by industry and overseen by NDDH. The closest ambient air monitor to the Falkirk Mine is the Hanover station. The TRNP-NU station is the closest station to Falkirk that is in a Class I area. Please refer to *Figure 2 Ambient Air Monitoring Sites in North Dakota* for the relative locations of monitoring sites in relation to the Falkirk Mine.

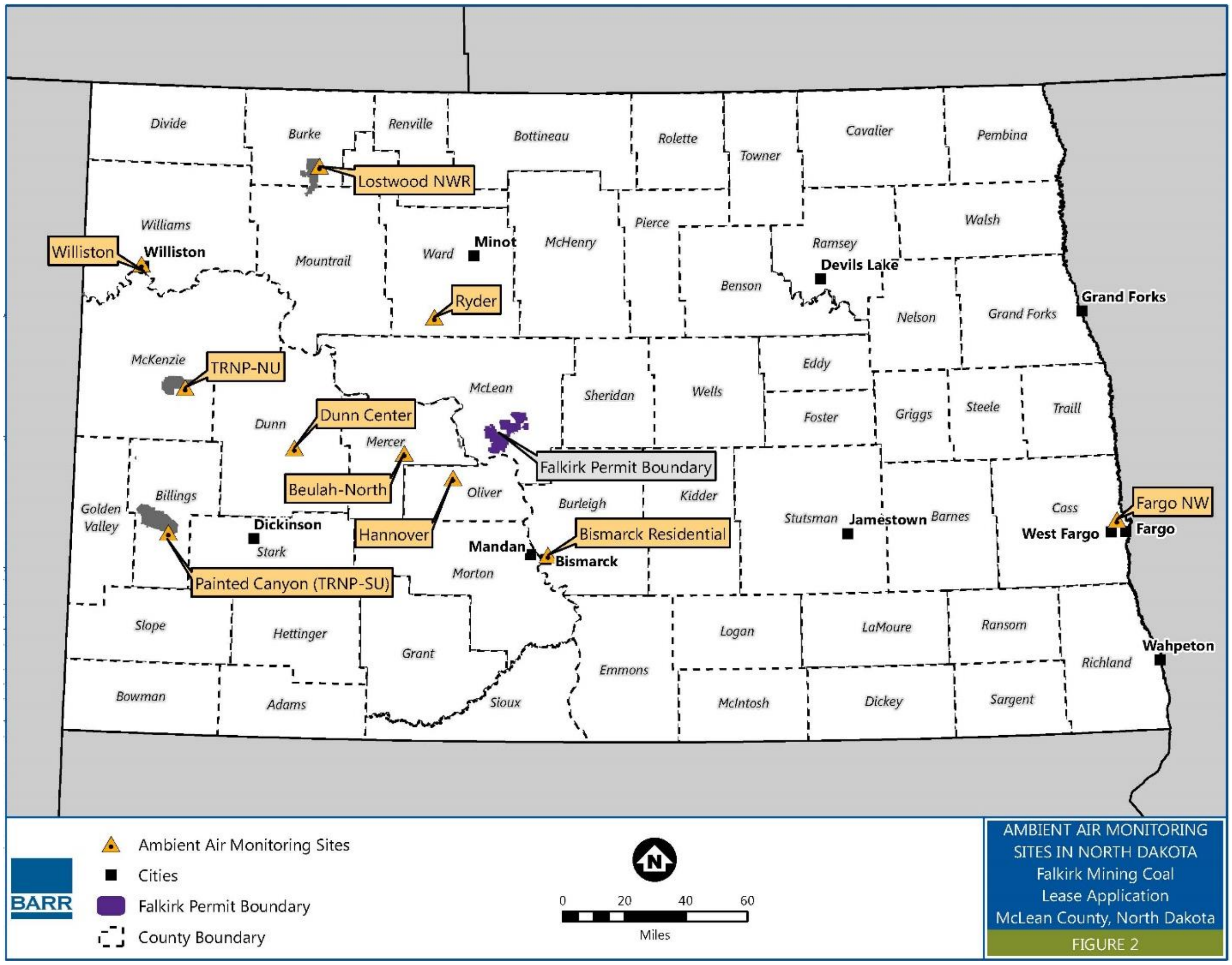

Figure 2 Ambient Air Monitoring Sites in North Dakota

Table 1 NAAQS Standard and Monitored Concentrations at Hanover and *Table 2 NAAQS Standard and Monitored Concentrations* at TRNP-NU, respectively, list the NAAQS and recorded levels at the Hanover and TRNP-NU monitoring sites based on the NDDH's 2017 Annual Report (NDDH, 2017). The only station in the NDDH network that monitors CO is the Bismarck station. Monitored CO concentration in 2016 at the Bismarck station are well below the NAAQS at 0.779 ppm using a 1-hour averaging time and 0.4 ppm using an 8-hour averaging time. No monitors in the NDDH network monitor for lead because the NDDH has determined that the state has low ambient lead concentrations and no significant sources of lead (NDDH, 2017).

Table 1 NAAQS Standard and Monitored Concentrations at Hanover

Pollutant	Type	Averaging Time	Federal Standard	Form	2016	2015	2014	2013	2012
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
Lead	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	98th percentile of 1-hour daily max. concentrations averaged over 3 years	14 ppb	16 ppb	16 ppb	10 ppb	17 ppb
NO_2	primary and secondary	annual	53 ppb	Annual mean	2.09 ppb	2.18 ppb	2.17 ppb	1.72 ppb	2.11 ppb
O_3	primary and secondary	8-hour	75 ppb	Annual 4th-highest daily max. 8-hour concentration, averaged over 3 years	59 ppb	61 ppb	59 ppb	56 ppb	58 ppb
$PM_{2.5}$	primary	annual	12 μ/m^3	Annual mean, averaged over 3 years	4.3 μ/m^3	4.9 μ/m^3	5.2 μ/m^3	4.9 μ/m^3	4.9 μ/m^3
$PM_{2.5}$	secondary	annual	15 μ/m^3	Annual mean, averaged over 3 years	4.3 μ/m^3	not reported	not reported	not reported	not reported
$PM_{2.5}$	primary and secondary	24-hour	35 μ/m^3	98th percentile, averaged over 3 years	18 μ/m^3	19 μ/m^3	16 μ/m^3	14.4 μ/m^3	14.3 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	72 μ/m^3	108 μ/m^3	80 μ/m^3	12.3 μ/m^3	14 μ/m^3
SO_2	primary	1-hour	75 ppb	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years	10 ppb	14 ppb	24 ppb	24 ppb	40 ppb
SO_2	secondary	3-hour	50 ppb	Not to be exceeded more than once per year	not reported	not reported	not reported	39 ppb	50 ppb

Sources:

Annual Report – North Dakota Ambient Air Quality Monitoring Program – Network Plan with Data Summary (NDDH, 2017).

Annual Report – North Dakota Ambient Air Quality Monitoring Program – Network Plan with Data Summary (NDDH, 2016).

Annual Report – North Dakota Ambient Air Quality Monitoring Program – Network Plan and Five Year Network Assessment with Data Summary (NDDH, 2015).

Annual Report – North Dakota Ambient Air Quality Monitoring Data Summary 2013 (NDDH, 2014).

Annual Report – North Dakota Ambient Air Quality Monitoring Data Summary 2012 (NDDH, 2013).

Table 2 NAAQS Standard and Monitored Concentrations at TRNP-NU

Pollutant	Type	Averaging Time	Federal Standard	Form	2016	2015	2014	2013	2012
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
Lead	primary and secondary	Rolling 3 month average	0.15 μ/m^3	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	12 ppb	12 ppb	11 ppb	11 ppb	9 ppb
NO_2	primary and secondary	annual	53 ppb	Annual mean	1.30 ppb	1.66 ppb	1.64 ppb	1.16 ppb	1.2 ppb
O_3	primary and secondary	8-hour	75 ppb	Annual 4th-highest daily max. 8-hour concentration, averaged over 3 years	57 ppb	58 ppb	57 ppb	58 ppb	59 ppb
$PM_{2.5}$	primary	annual	12 μ/m^3	Annual mean, averaged over 3 years	2.8 μ/m^3	3.4 μ/m^3	4.6 μ/m^3	6.5 μ/m^3	8.1 μ/m^3
$PM_{2.5}$	secondary	annual	15 μ/m^3	Annual mean, averaged over 3 years	2.8 μ/m^3	not reported	not reported	not reported	not reported
$PM_{2.5}$	primary and secondary	24-hour	35 μ/m^3	98th percentile, averaged over 3 years	17 μ/m^3	18 μ/m^3	15 μ/m^3	11.4 μ/m^3	17.4 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	57 μ/m^3	57 μ/m^3	30 μ/m^3	7.1 μ/m^3	9.4 μ/m^3
SO_2	primary	1-hour	75 ppb	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years	6 ppb	6 ppb	8 ppb	6.5 ppb	10.1 ppb
SO_2	secondary	3-hour	50 ppb	Not to be exceeded more than once per year	not reported	not reported	not reported	9 ppb	10 ppb

Sources:

Annual Report – North Dakota Ambient Air Quality Monitoring Program – Network Plan with Data Summary (NDDH, 2017).

Annual Report – North Dakota Ambient Air Quality Monitoring Program – Network Plan with Data Summary (NDDH, 2016).

Annual Report – North Dakota Ambient Air Quality Monitoring Program – Network Plan and Five Year Network Assessment with Data Summary (NDDH, 2015).

Annual Report – North Dakota Ambient Air Quality Monitoring Data Summary 2013 (NDDH, 2014).

Annual Report – North Dakota Ambient Air Quality Monitoring Data Summary 2012 (NDDH, 2013).

Criteria pollutant emissions from coal combustion are indirect emissions associated with the Falkirk Mine. Two coal combustion power plants, Coal Creek Station and Spiritwood Station combust coal from Falkirk. For background, the indirect emissions associated with these two power plants are presented in *Table 3 Annual Criteria Pollutant Emissions at Coal Creek Station and Spiritwood Station 2012-2016*.

Table 3 Annual Criteria Pollutant Emissions at Coal Creek Station and Spiritwood Station 2012-2016

Year	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	TOC	Unit
2012	194	78	16,272	8,655	1,807	145	tons
2013	185	74	15,455	8,008	1,732	139	tons
2014	193	77	15,865	8,042	1,836	144	tons
2015	144	58	15,510	8,812	1,731	155	tons
2016	134	54	13,317	7,857	1,731	140	tons
Average	170	68	15,284	8,275	1,767	144	tons

Source:
GRE Coal Creek Station Annual Inventory Reports 2012 - 2016 (GRE, 2013) (GRE, 2014) (GRE, 2015) (GRE, 2016) (GRE, 2017) and Spiritwood Station Annual Inventory Reports 2014, 2015, 2016 (GRE, 2015) (GRE, 2016) (GRE, 2017).

3.2.2 Hazardous Air Pollutants

In addition to criteria pollutants, the EPA regulates a list of hazardous air pollutants (HAPs). 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, chlorine, and mercury compounds. Most air toxics are generated from mobile or stationary, human-made sources. Major stationary sources are sources that emit 10 tons per year of any listed HAP. Area sources are defined as smaller facilities that release less than 10 tons per year of any listed HAP. Stationary source facilities that meet the reporting criteria must report their releases to the EPA through the Toxics Release Inventory (TRI) Program (USEPA, 2016). As a synthetic minor source, Falkirk emits less than 10 TPY of any listed HAP and less than 25 TPY of all HAPs combined. HAP emissions are also generated indirectly from the combustion of coal. HAP emissions from Coal Creek Station and Spiritwood Station, which both combust Falkirk coal are summarized in *Table 4 Annual Emissions for HAPs at Coal Creek Station and Spiritwood Station 2012-2016*.

Table 4 Annual Emissions for HAPs at Coal Creek Station and Spiritwood Station 2012-2016

Year	Total Metal HAPs	Total VOC HAPs	HCl	HF	H_2SO_4	Unit
2012	6.61	3.12	0.75	79.00	21.50	tons
2013	6.28	2.99	0.72	75.50	19.50	tons
2014	6.79	2.99	3.42	75.80	69.60	tons
2015	7.00	4.05	37.80	43.80	21.25	tons
2016	5.98	3.59	34.85	39.70	17.55	tons
Average	6.53	3.35	15.51	62.76	29.88	tons

Source:
GRE Coal Creek Station Annual Inventory Reports 2012 - 2016 (GRE, 2013) (GRE, 2014) (GRE, 2015) (GRE, 2016) (GRE, 2017) and Spiritwood Station Annual Inventory Reports 2014, 2015, 2016 (GRE, 2015) (GRE, 2016) (GRE, 2017).

3.2.3 Mercury

Mercury is a naturally occurring metal, but also a potent neurotoxin that affects humans and other organisms (USGS, 2000). 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 (UNEP, 2013). Coal combustion is a major source of anthropogenic mercury emissions and coal combustion at power plants is the primary source of mercury emissions by sector in North Dakota (UNEP, 2013). Coal Creek Station, which combusts coal from the Falkirk Mine, is the closest power plant to the location of the proposed action. Power plants within North Dakota report mercury emissions to the NDDH via Annual Emission Inventory Reports (AEIR). Mercury emissions for the past five years from Coal Creek Station, as well as Spiritwood Station, which both combust Falkirk Mine coal are summarized in *Table 5 Annual Mercury Emissions at Coal Creek Station and Spiritwood Station 2012-2016*.

Table 5 Annual Mercury Emissions at Coal Creek Station and Spiritwood Station 2012-2016

Power Plant	2012	2013	2014	2015	2016	Unit
Coal Creek Station	800	900	900	880	320	pounds
Spiritwood Station			8	20	10.8	pounds

Source:
GRE Coal Creek Station Annual Inventory Reports 2012 - 2016 (GRE, 2013) (GRE, 2014) (GRE, 2015) (GRE, 2016) (GRE, 2017) and Spiritwood Station Annual Inventory Reports 2014, 2015, 2016 (GRE, 2015) (GRE, 2016) (GRE, 2017).

The EPA's Mercury and Air Toxics Standards (MATS) set emissions standards on all HAPs. Recently enacted Maximum Achievable Control Technology (MACT) Standards are technology-based emissions limitations for mercury and other toxic air pollutants. These standards reflect levels achieved by the best-performing sources currently in operation and require the installation of mercury controls to achieve over 50 percent reduction from historical levels starting in June 2015. The final rule sets standards for all HAPs emitted by coal- and oil-fired electric generating units with a capacity of 25 megawatts or greater. All regulated units are considered major under the final rule. EPA did not identify any size, design, or engineering distinction between major and area sources.

3.2.4 Greenhouse Gas/Climate Change

Greenhouse gases (GHGs) 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 greenhouse gases (GHGs), along with other climate-influencing environmental factors, cause a net warming of the atmosphere. GHGs include CO_2, methane (CH_4), nitrous oxide (N_2O), water vapor, ozone (O_3), fluorocarbons, and sulfurhexafluoride gas (SF_6). These are called GHGs 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 GHGs 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 0.85°C from 1880-2012; during the period from 1901 to 2012, almost the entire planet experienced higher surface temperatures. Because temperature is a part of climate, the phenomenon of global warming is both an element of and a driving force behind climate change (IPCC, 2014).

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 (CCSP, 2009). In 2014, the Intergovernmental Panel on Climate Change (IPCC) produced the Climate Change Synthesis Report and Summary for Policymakers (IPCC, 2014). The Report states 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 previously recorded. This has led to atmospheric concentrations of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (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.

These climatic changes are impacts in and of themselves; however, they can also affect other aspects of the environment including desert distribution, sea level, 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 (IPCC, 2014). North Dakota's average temperature increased faster than any other state in the contiguous United States, and the number of days with temperatures over 100°F is projected to double in the Northern Plains by 2050. Warmer temperatures lengthen the growing season, which could increase plant growth or allow for a second planting. However, summer precipitation is not projected to rise, which increases vulnerability to drought conditions, while 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 (USEPA, 2017). Thus, the causes and effects of climate change can be described as follows. First, GHGs 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.

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_2eq) 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 CFR Part 98, Table A-1). Greenhouse gases directly emitted from the mining of coal are from diesel and gasoline-powered vehicles. Indirectly, GHGs 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. Further indirect emissions are generated when the coal is combusted by the user.

3.2.4.1 Greenhouse Gas Emissions

Coal from Falkirk is combusted at two power plants, Coal Creek Station and Spiritwood Station. The indirect emissions generated at these two facilities are summarized in *Table 6 Annual Greenhouse Gas Emissions at Coal Creek Station and Spiritwood Station 2012-2016*.

Table 6 Annual Greenhouse Gas Emissions at Coal Creek Station and Spiritwood Station 2012-2016

Year	Coal Combusted	CO_2	CH_4	N_2O	CO_2e	Unit
2012	7,225,823	11,060,356	1,245	181	11,114,323	tons
2013	6,927,877	10,604,299	1,194	174	10,656,040	tons
2014	7,026,579	10,755,379	1,211	176	10,807,858	tons
2015	7,211,153	11,037,901	1,242	181	11,091,758	tons
2016	6,484,546	9,925,705	1,117	163	9,974,135	tons
Average	6,975,196	10,676,728	1,202	175	10,728,823	tons

Source:

Emissions calculated from reported coal use and emission factors in Table C-1 and C-2 to Subpart C of 40 CFR Part 98 (USEPA, 1995).

The EPA collects GHG emissions data in the U.S. 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 7 1990-2015 Estimated US Greenhouse Gas Emissions Allocated to Economic Sectors (in Million Metric Tons of CO2e)* by GHG and for selected source sectors. GHG from coal mining are included in Industry emissions and were estimated to be 60.9 MMT in 2015, or approximately 1% of the total US GHG Inventory. According to the U.S. Energy Information Administration (EIA, 2017), US coal production in 2015 was 869,941,000 short tons of which 28,802,000 short tons (approximately 3.3%) were produced from four surface coal mines in North Dakota. Assuming roughly proportional emissions across coal mining operations, the four 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 two power plants combusting Falkirk coal account for approximately 0.5% of the electric power industry 2015 GHG emissions and less than 0.2% of the 2015 US GHG inventory.

Table 7 1990-2015 Estimated US Greenhouse Gas Emissions Allocated to Economic Sectors (in Million Metric Tons of CO_2e)

Sector	1990	2005	2011	2015
Electric Power Industry	1,862.5	2,441.6	2,197.3	1,941.4
Transportation	1,551.2	2,001.0	1,800.0	1,806.6
Industry	1,626.3	1,467.1	1,378.6	1,411.6
Agriculture	526.7	574.3	592.0	570.3
Commercial	418.1	400.7	406.5	437.4
Residential	344.9	370.4	356.3	372.7
US Territories	33.3	58.1	46	46.6
Total Emissions	6,363.1	7,313.3	6,776.7	6,586.7
Land Use, Land-Use Change, and Forestry (Sink)	(819.6)	(731.0)	(749.2)	(758.9)
Net Emissions (Sources and Sinks)	**5543.5**	**6,582.3**	**6,027.6**	**5,827.7**

Source: Table 2-10 (USEPA, 2017)

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

On a federal level, the EPA has implemented various programs to encourage the reduction of GHG emissions to address climate change. EPA has promulgated rules under the CAA to regulate greenhouse gas emissions, finalizing rules under Section 111(d) of the CAA to cut carbon emissions from existing fossil fuel-fired power plants. The rule is commonly referred to as “the Clean Power Plan”. Executive Order 13763 called for a review of the Clean Power Plan and although a repeal of the plan was proposed on October 16, 2017, the possible repeal is not finalized. The Clean Power Plan would establish goals for carbon reduction from power plants, but the states would determine the means of achieving the standards. Under the final Clean Power Plan, North Dakota will be required to reduce CO_2 emissions from existing power plants on the order of 45 percent (USEPA, 2015). The Clean Power Plan would not directly regulate emissions from the Mine, but would regulate emissions from downstream users of the coal produced by the Mine. The pending repeal of the Clean Power Plan has introduced additional uncertainty in the extent of GHG emissions reductions that may occur in the near future.

3.2.4.2 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 (IWG), to assist agencies in addressing Executive Order (EO) 12866, which requires federal agencies to assess the cost and the benefits of proposed regulations as part of their regulatory impact analyses. The SCC is an estimate of the economic damages associated with an increase in carbon dioxide 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 carbon dioxide (CO2) emissions into cost-benefit analyses of regulatory actions that have small, or 'marginal,' impacts on cumulative global emissions." Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 February 2010 (withdrawn by EO13783). 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 this Falkirk Mine EA for a number of reasons. Most notably, this action is not a rulemaking for which the SCC protocol was originally developed. Second, on March 28, 2017, the President issued Executive Order 13783 that, among other actions, withdrew the Technical Support Documents upon which the protocol was based and disbanded the earlier Interagency Working Group on Social Cost of Greenhouse Gases. The Order further directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). In compliance with OMB Circular A-4, interim protocols have been developed for use in the rulemaking context. However, the Circular does not apply to project decisions, so there is no Executive Order requirement to apply the SCC protocol to project decisions.

Further, NEPA does not require a cost-benefit analysis (40 C.F.R. § 1502.23), although NEPA 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, inclusion solely 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, inasmuch as such impacts might be viewed by another person as negative or undesirable impacts due to potential increase in local population, competition for jobs, and concerns that changes in population will 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 carbon dioxide emissions - typically expressed as a one metric ton 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" (Rose, et al., 2014). 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. However, the dollar cost figure is generated in a range and provides little benefit in assisting the authorized officer's decision for project level analyses. For example, in a recent environmental impact statement, OSM 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. 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 social cost of carbon resulting from seven additional months of operation under the mining plan, and that the SCC protocol and similar models were developed to estimate impacts of regulations over long timeframes, this EA quantifies direct and indirect GHG emissions and evaluates these emissions in the context of global, U.S., and North Dakota GHG emission inventories as discussed in Sections 4.2 and 5.2.

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) the IWG, technical supporting documents, and associated guidance have been withdrawn; 3) NEPA does not require cost-benefit analysis ; and 4) 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.

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 (OSMRE, 1989). Direct impacts are those that are caused directly by the proposed activities at the same time and place (40 CFR 1508.8(a)). Indirect impacts are those that are removed in time and place (40 CFR 1508.8(b)). This chapter incorporates Chapter 4.0 of the BLM EA by reference[4] and only provides supplemental information regarding air quality where relevant to the supplemental 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. The Mine currently operates under North Dakota Air Pollution Control Minor Source Permit to Operate #O79002. The NDDH sets standards to ensure operations under the Minor Source Permit are within State and Federal air quality regulations. In accordance with the Falkirk Mine Permit to Operate, the owner/operator keeps records of monthly coal production (tons per month) and may not exceed the allowable annual production limit listed in the Permit (20.0 MMTPY for the truck dump, primary crushing station, and conveyor; 34.0 MMTPY for the secondary crushing station and conveyor; and 14.0 MMTPY for the east dump/primary crusher/cable belt system). At the Mine, the only reportable sources included in the permit, and therefore included in the ND statewide emission inventories, are two lignite processing and handling facilities, one 16,000-ton storage silo, and one cable belt conveyor system. Emission limits to the controlled sources limit emissions from these units, and in 2016 emitted approximately 9.97 tons of total particulates based on mine production. Please refer to *Appendix A Air Emissions Information,* for details regarding the emission calculations.

Other sources of direct emissions from mining are fugitive emissions from coal excavation and reclamation activities and 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. Please refer to *Appendix A Air Emissions Information,* for details regarding the calculations related to fugitive emissions. The fugitive emissions calculated for this EA use basic screening equations and actual production information at the Falkirk Mine. The screening equations provide high-end estimates that are intended to overestimate and

[4] The BLM EA is available on their eplanning website at: https://eplanning.blm.gov/epl-front-office/projects/nepa/67410/105731/129311/DOI-BLM-MT-C030-2016-0020-EA.pdf

not underestimate actual emissions. Fugitive emissions are generally not reportable emissions.

In accordance with the Fugitive Dust Control Plan in Section 3-4 of the Falkirk Mine Permit to Engage in Surface Coal Mining and Reclamation Operations (Appendix B of (BLM, 2017)), fugitive dust emissions would be reduced by removing topsoil and subsoil in increments, only disturbing areas necessary for operations at any one time. All areas of disturbance would be stabilized as soon as possible using approved revegetation techniques. Fugitive dust from equipment activities and traffic would be reduced by treating road surfaces with approved stabilization agents; using water on roads and problem areas associated with construction, leveling, and other traffic activities; and using dust suppressants during dry periods on haulage and access roads. The Falkirk Mine also is required to implement fugitive dust control measures listed in the air permit for the entire site.

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 (CATF, 2009). Based on the diesel combustion at the Mine, approximately 36.4 tons of black carbon was generated per year from 2012 to 2016.

Another group of pollutants is nitrogen oxides (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 ozone, 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, as previously shown by *Table 1 NAAQS Standard and Monitored Concentrations at Hanover* and *Table 2 NAAQS Standard and Monitored Concentrations at TRNP-NU*. NO_x is created at the Mine by the burning of diesel and, in very small amounts, by coal blasting. Please refer to *Appendix A Air Emissions Information***,** for calculations relating to tailpipe and blasting NO_x emissions.

4.2.1.2 Indirect Emissions

Falkirk Mine sells coal to two facilities: Coal Creek Station and Spiritwood Station, both coal-fired power plants. Coal Creek Station is a 1,100-megawatt facility with two generating units; one that began commercial operation in 1979 and the second that began operating in 1980. Spiritwood Station is a 99-megawatt facility and began operations briefly in 2010 before shutting down for economic reasons. Operations resumed in 2014 and have continued to date. These plants work 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. Spiritwood Station also provides process steam to adjacent industrial consumers.

On a yearly basis, approximately 93 percent of the coal from the Falkirk Mine is consumed at Coal Creek Station and the remaining 7 percent is consumed at Spiritwood Station. Coal Creek Station and Spiritwood Station each maintain Title V Permits to Operate, issued by the NDDOH. These permits are required for any operations that emit 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. Each facility has technology in place that reduces the amount of pollutants from coal combustion to levels acceptable under NDDH and EPA regulations.

One particular pollutant of interest from power plant emission is mercury. Mercury is a naturally occurring element, but releases from power plants are the largest source of anthropogenic mercury in the United States (UNEP, 2013). Once released into the atmosphere, mercury deposits onto land or into water. Once deposited, microorganisms can transform it into methylmercury, which is highly toxic, and bioaccumulates in fish and other organisms. Mercury can cause health effects such as harm to the brain, heart, kidneys, lungs, and immune system if exposure levels are high enough. It can also have ecological impacts, particularly to fish, birds, and mammals that eat fish. Mercury exposure to ecological communities can cause reduced reproduction, slow growth and development, and death. When coal from the Mine is combusted, mercury is released.

4.2.2 Proposed Action

4.2.2.1 Direct Impacts

The mine plan operation under the Proposed Action at the Mine are not anticipated to substantially change; the coal from the Section 10 lease tract accounts for approximately seven months of operations. The overall annual amount of particulate and gaseous air pollution is also not anticipated to increase from current levels. Dust suppression techniques are utilized throughout Mine operations to manage fugitive particulate emissions. One common dust suppression technique is to apply water from sedimentation ponds to gravel roads throughout the Mine.

Specifically, it is estimated that the mining of the Section 10 lease tract coal in the Proposed Action would result in the use of approximately 23,183,000 gallons of diesel fuel. This equals approximately 260,000 short tons of CO_2 emissions per year from the mining of the Section 10 lease tract coal.[5]

Direct emissions from equipment used on the Mine to mine the Section 10 lease tract coal in the Proposed Action were estimated using the average total hours per year from 2012 to 2016 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.[6] 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.

[5] 1 gallon diesel combusted = 22.50 pounds CO_2
[6] Calculations were completed using the formula: tons of emissions=(x g/kw-hr*y kw*z average total hours)/907,185 g

Emission factors for SO_X and TOC were taken from EPA's *AP-42, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* (USEPA, 1995). These amounts are reported in *Table 8 Direct Fleet Emissions from Section 10 Lease Tract* Coal, tons.

Table 8 Direct Fleet Emissions from Section 10 Lease Tract Coal, tons

Fleet[1]	NO_X[2,3]	SO_X[4]	CO[2]	PM_{10}[2]	$PM_{2.5}$[2]
Hydraulic Shovels	28	0.04	4.6	0.3	0.3
Rubber Tire Dozers	11	0.02	1.9	0.1	0.1
Track Dozers (D10T)	32	0.06	24.2	1.4	1.4
Track Dozers (D11T)	81	0.11	12.8	0.9	0.9
Front End Loaders	66	0.06	9.6	1.0	1.0
Motor Graders	43	0.08	26.1	1.6	1.6
Scrapers	23	0.05	23.4	1.0	1.0
Coal Haulers	263	0.25	36.6	6.0	6.0
Overburden Truck Fleet	700	0.65	97.5	16.0	16.0
Total	*1,248*	*1.3*	*237*	*28*	*28*

[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 EPA's *AP-42* Chapter 3 Sections 3 and 4 (USEPA, 1995). 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 1,200 pounds NO_x, 140 pounds SO_2, and 4,600 pounds CO would be generated from the seven months of mining the Section 10 lease tract coal. Assuming the amount of diesel fuel combusted stays consistent, the amount of black carbon generated from mining the Section 10 lease tract coal in the Proposed Action would be approximately 21.2 tons.

Direct fugitive emissions are generated from mine and vehicle activities related to coal extraction, stockpiling, reclamation, and vehicle traffic. *Table 9 Estimated Direct Fugitive Emissions from Section 10 Lease Tract* Coal Activities shows the anticipated direct fugitive emissions related to mining the Section 10 lease tract coal. Details regarding the calculation of fugitive emissions are in *Appendix A Air Emissions Information*.

Table 9 Estimated Direct Fugitive Emissions from Section 10 Lease Tract Coal Activities

Fugitive Sources[1]	PM_{10}, tons	$PM_{2.5}$, tons
Road Emissions	3,930	393
Truck Loading	4.5	0.1
Bull Dozing	74.0	2.2
Dragline	5.2	0.1
Grading	40.7	2.1
Active Storage Pile	0.4	0.4
Total	4,055	398

[1] Emission Factors developed from factors in *AP-42* Chapter 13 Section 2.2 and Chapter 11 Section 9 (USEPA, 1995)

Please see *Appendix A Air Emissions Information* for details regarding direct emissions calculations**.** *Table 10 Total Annual Direct Emissions* shows the emissions including fleet emissions, permitted emission points, blasting and fugitive emissions from both the proposed mining of Section 10 lease tract coal and coal from other areas not in the Section 10 lease tract (non-federal coal). Compared to total North Dakota state emissions of hundreds of thousands of tons (see Section 5.2.1) the direct emissions from Falkirk are minor, even less than one percent of statewide emissions. As such, impacts of direct emissions from the Proposed Action would be minor and short-term, extending operations at the Falkirk Mine by seven months and staying in compliance with existing state air permits and NAAQS.

Table 10 Total Annual Direct Emissions

	From Section 10 lease tract coal, tons (A)	From coal not in Section 10 lease tract, tons (B)	Total Falkirk mine coal, tons (A+B)
NO_X	1,248	892.0	2,140.8
SO_X	1.4	1.0	2.4
CO	239.0	170.7	409.7
PM_{10}	4,089.6	2,921.1	7,010.7
$PM_{2.5}$	432.5	308.9	741.4
CO_2	52,164	37,260.2	89,424.6
CH_4	2.1	1.5	3.6
N_2O	0.4	0.3	0.7
CO_2e	52,290	37,350.3	89,640.8
Black carbon	21.2	15.2	36.4

4.2.2.2 Indirect Impacts

Indirect emissions resulting from the combustion of ½ Section 10 lease tract coal proposed in the Proposed Action were calculated based on historical emissions from each facility in which Falkirk Mine coal is combusted: Coal Creek Station and Spiritwood Station. Falkirk Mine is assumed to be the sole provider of coal to these facilities. Emission data was derived from the NDDH and Annual Emissions Inventory Reports (2012-2016). Anticipated Section 10 lease tract coal combusted at each facility was then estimated based on the average amount of coal used at each facility. These emission estimates are located in *Table 11 Estimated Indirect Annual Emissions for Section 10 Lease Tract Coal in the* Proposed Action*.*

Table 11 Estimated Indirect Annual Emissions for Section 10 Lease Tract Coal in the Proposed Action

	Tons Emissions
PM_{10}	99
$PM_{2.5}$	40
SO_2	8,916
NO_x	4,827
CO	1,031
TOC	84
Mercury	0.22
Selenium	0.06
Total Metals	3.8
Total HAP VOC	2.0
HCl	9
HF	37
H_2SO_4	17
CO_2	6,228,092
CH_4	701
N_2O	102
CO_2e	6,258,480

Source:
GRE Coal Creek Station Annual Inventory Reports 2012 - 2016 (GRE, 2013) (GRE, 2014) (GRE, 2015) (GRE, 2016) (GRE, 2017) and Spiritwood Station Annual Inventory Reports 2014, 2015, 2016 (GRE, 2015) (GRE, 2016) (GRE, 2017).

For comparison, the total indirect emissions from the combustion of all coal mined at the Falkirk Mine for the period 2012-2016 are shown in *Table 6 Annual Greenhouse Gas Emissions at Coal Creek Station and Spiritwood Station 2012-2016, Table 3 Annual Criteria Pollutant Emissions at Coal Creek Station and Spiritwood Station 2012-2016,* and *Table 4 Annual Emissions for HAPs at Coal Creek Station and Spiritwood Station 2012-2016***.** Emissions related to the Proposed Action would be minor and short-term by providing coal for seven months and maintaining compliance with state issued air permits and NAAQS. Note that Spiritwood Station began operations in 2014 so emissions in 2012 and 2013 are solely from Coal Creek Station.

NDDH relies on regional monitors in the state monitoring system as shown in *Figure 2 Ambient Air Monitoring Sites in North Dakota* to demonstrate attainment of the NAAQS. North Dakota policy is that applicable facilities report emissions as required by their permit and that air quality attainment is maintained as demonstrated by the regional monitoring network. As such, facility specific ambient air quality modeling data is not available for demonstration of NAAQS attainment. North Dakota is in attainment of all criteria pollutants as shown in *Table 1 NAAQS Standard and Monitored Concentrations at Hanover* and *Table 2 NAAQS Standard and Monitored Concentrations at TRNP-NU*. Historical emissions may be compared to the monitored results to relate a level of ambient air quality associated with the reported or estimated emissions. The monitored ambient air is expected to continue to have consistent concentrations of monitored pollutants as related to the proposed action.

Coal Creek Station and Spiritwood Station operate under Title V Permits to Operate. The permits are legally-enforceable documents that detail what the facilities must do to control air pollutants. These permits are issued and enforced by the NDDH as required by the Clean Air Act. Each permit specifically documents limits of air pollutants for each emitting source unit. Reporting requirements are also described in the Title V permits. These permits can be found on the NDDH website for air quality permits.[7]

Advances in technology and efficiency have allowed coal-fired power plants across North Dakota to greatly reduce their emissions. Electrostatic precipitators and filters remove a majority of fly ash from the combusted coal. Low NO_x burners have helped reduce nitrogen oxide emissions.

Greenhouse gas emissions under the Proposed Action are expected to be minor and short term when compared to state emissions. GHG emissions from the combustion of Section 10 lease tract coal at Coal Creek Station and Spiritwood Station together account for approximately 19% of the North Dakota GHG inventory and approximately 0.1% of the total US GHG inventory (USEPA, 2017) (USEPA, 2018).

In addition to CO_2, other airborne pollutants are produced during the combustion of coal. These emissions are reported to the NDDH on a yearly basis. The levels of NO_x, SO_2, and PM within the state of North Dakota have been steadily decreasing due to implementation of Best Available Retrofit Technology (BART) controls on BART eligible facilities such as Coal Creek Station. The North Dakota State Implementation Plan for Regional Haze specifies that for Coal Creek Station BART for SO_2 is achieved with modifications to the wet scrubbers and the addition of a unique coal drying operation using waste heat and BART for NO_x to be achieved with low NO_x burners with separated overfired air (LNC3+) (NDDH, 2010). As part of the Supplement No. 2 to Regional Haze State Implementation Plan (NDDH, 2012) the NDDH reaffirmed its position regarding BART for NO_x at Coal Creek Station. As a major source that began operations after the BART eligibility timeframe, Spiritwood Station is subject to Best Available Control Technology (BACT). The implementation of these technologies as well as the implementation of BART at other facilities in the state has resulted in a decreasing trend in both NO_x and SO_2 emissions from power plants in North Dakota as shown in *Figure 3 Sulfur Dioxide and Nitrogen Oxides Emissions from Power Plants in North Dakota* (USEPA, 2017).

[7] http://www.ndhealth.gov/EHS/FOIA/AQPermits/AQPermitOperating.aspx

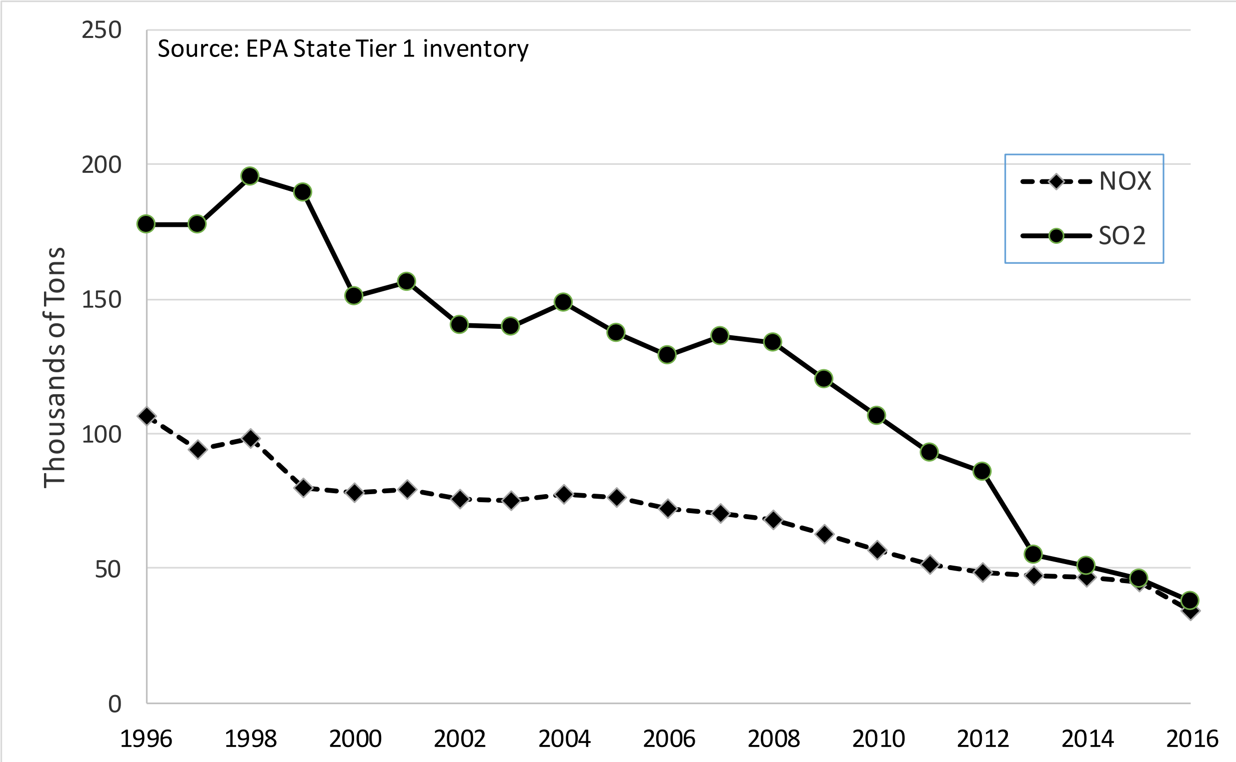

Figure 3 Sulfur Dioxide and Nitrogen Oxides Emissions from Power Plants in North Dakota

Power plants within North Dakota report mercury emissions to the NDDH. Much like NO_x and SO_2, improvements in technology have resulted in decreasing emissions of mercury. The EPA's Mercury and Air Toxics Standards (MATS) set emissions standards on all HAPs. Recently enacted Maximum Achievable Control Technology (MACT) Standards require the installation of mercury controls to achieve over 50 percent reduction from historical levels starting in June 2015. This effectively provides greater reduction of mercury emissions from North Dakota emission sources. More specifically, mercury controls at Coal Creek Station include use of bromine and a patented scrubber additive (GRE, 2016). Please refer to *Table 5 Annual Mercury Emissions at Coal Creek Station and Spiritwood Station* for a summary of mercury emissions at Coal Creek Station and Spiritwood station for the past five years.

Lignite coal from the Falkirk Mine would continue to be combusted at Coal Creek Station and Spiritwood Station even if the mining of the ½ Section 10 coal proposed by this document did not occur. As shown in *Table 11 Estimated Indirect Annual Emissions for Section 10 Lease Tract Coal in the* Proposed Action, emissions of CO2, criteria pollutants, and HAPS, from coal combustion would be minor and short term by providing coal for seven months and remaining in compliance with state issued permits and NAAQS.

Technological advances have recently been developed as the result of regulations. One such regulation is the New Source Performance Standards (NSPS). This regulation required new or modified facilities to meet emissions ratings and demonstrate compliance with the state implementation plan. The Acid Rain Program created under Title IV of the 1990 CAA Amendments required emission reductions of SO_2 and NO_x. The MATS rule previously discussed in Section 3.2.3 required similar reductions in HAPs. In order to continue operating, Coal Creek Station and Spiritwood Station must meet the requirements outlined in those regulations. As shown in *Table 5 Annual Mercury Emissions at Coal Creek Station and Spiritwood Station 2012-2016,* the indirect mercury emissions from Falkirk Mine coal show a decreasing trend over the past five years. As technologies continue to advance, it is reasonable to assume that further reductions in emissions could be achieved. Because future advancements and responses to regulation are facility-specific and have not yet been determined, it is reasonable to assume the technological advances would continue the past trend of reducing emissions.

4.2.3 No Action

Under the No Action Alternative, the ASLM would not approve the mining plan to recover the coal in ½ Section 10. Impacts from direct and indirect emissions have resulted from current mining activity and, therefore, under this alternative, direct and indirect emissions would be similar to the Proposed Action but would not be extended for an additional seven months.

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 CFR 1508.7). This chapter incorporates Chapter 5.0 of the BLM EA by reference[8] and only provides supplemental information regarding air quality where relevant to the supplemental 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 the Section 10 lease tract would be mined (i.e., seven months). The geographic extent of cumulative impacts includes McLean County and adjacent counties Mercer County and Oliver County. No significant, adverse, cumulative effects were identified in the cumulative effects analysis.

5.1.2 Past, Present, and Reasonably Foreseeable Actions

Currently, there are five operating surface coal mines in North Dakota that produced approximately 29.18 million tons of coal in 2016: Beulah Mine, Center Mine, Coyote Creek Mine, Falkirk Mine, and Freedom Mine. Section 5.1 of the BLM EA is incorporated by reference and provides a detailed description of each mine (BLM, 2017). *Table 12 Summary of 2016 and Anticipated Future Lignite Production in* North Dakota presents a summary of the annual production of each mine in 2016. Future production at each of these mines is expected to be consistent with 2016 levels except for Beulah Mine, which ended its coal supply contract with Coyote Power station in April, 2016 and Coyote Creek Mine, which began production in April 2016 and had its first year of full production in 2017. The anticipated future production levels for North Dakota surface mining is also shown in *Table 12 Summary of 2016 and Anticipated Future Lignite Production in* North Dakota and is not appreciably different from 2016 production levels. Production levels at Falkirk Mine are expected to be the same for the Proposed Action.

[8] The BLM EA is available on their eplanning website at: https://eplanning.blm.gov/epl-front-office/projects/nepa/67410/105731/129311/DOI-BLM-MT-C030-2016-0020-EA.pdf

Table 12 Summary of 2016 and Anticipated Future Lignite Production in North Dakota

Surface Mine	2016 Annual Coal Production, MMtons	Anticipated Future Coal Production, MMtons	Description of Anticipated Production Changes
Beulah Mine	2.5	0.5	Change in supply contracts
Center Mine	3.83	3.83	No anticipated change
Coyote Creek Mine	1.49	2.5	2016 production represents a partial year
Falkirk Mine	7.24	7.24	Additional seven months mine life from production of Section 10 lease tract coal. No change to annual production.
Freedom Mine	14.12	14.12	No anticipated change
Total	*29.18*	*28.19*	

Source:
USEIA 2016 Annual Coal Report (EIA, 2017) and North Dakota Mine Operators Data (BLM, 2017).

Coal Creek Station and other coal-fired power plants in the vicinity of the Section 10 lease tract are considered to be major stationary point sources (i.e., more than 100 TPY) for federally listed criteria pollutants (NDDH, 2017). A summary of the coal-fired power plants located in the area and considered to be major stationary point sources for CO, NO_x, VOCs, PM_{10}, and SO_2 is presented in *Table 13 Coal Fired Power Plants in North Dakota* (USEPA, 2017). The net electrical generation of each source is expected to remain relatively constant compared to 2014, except for Spiritwood station, which commenced operations in 2014. However, because Spiritwood is one of the smaller sources, the overall net generation in North Dakota is expected to be similar to that in 2014. Thus, overall impacts from electrical generation are expected to be relatively constant in the future.

One other major stationary source in the cumulative impact assessment area is the Dakota Gasification Company. The Dakota Gasification Company has added a urea manufacturing facility to the existing plant site, which is expected to begin operations in early 2018. This project adds to particulate and gaseous air pollutants in the area. As a major modification, direct impacts from the urea facility were addressed in PSD permitting and found to have no significant adverse impact (DGC, 2013). As the NAAQS levels have not been exceeded during the time of the Mine's operation, continued mining operations on a similar scale for seven additional months over the life of the mine are unlikely to cause a cumulative impact large enough to exceed the NAAQS standards even when combined with future projects, as those projects must also be permitted through the NDDH and be in compliance with the state implementation plan.

Table 13 Coal Fired Power Plants in North Dakota

	Nameplate Capacity, MW	2014 net Generation, MWh
Antelope Valley	869.8	5,838,431
Coal Creek Station	1,211.6	8,880,798
Coyote	450.0	2,745,038
Leland Olds	656.0	3,453,455
Milton R Young	734.0	4,557,992
R M Heskett	203.0	547,268
Spiritwood Station	106.2	32,125
Stanton	191.2	5,838,431

Source:
USEPA eGRID2014 (USEPA, 2017)

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 2016 reported levels did not exceed any NAAQS (see *Table 1 NAAQS Standard and Monitored Concentrations at Hanover*). 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 any facility receiving coal from the Falkirk Mine. As a result, the Proposed Action will extend the life of the mine by seven months, however, no changes to annual emissions of criteria pollutants or HAPs are expected from the Proposed Action. For perspective, the contribution of emissions from the Proposed Action in comparison with total reported statewide emissions in North Dakota is provided in *Table 14 North Dakota and Section 10 Lease* Tract Emissions. 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 14 North Dakota and Section 10 Lease Tract Emissions

	2016 Reported[1] Total North Dakota Emissions, tons	Average Direct Emissions[2] Section 10 Lease Tract, tons	Average Indirect Emissions Section 10 Lease Tract, tons	Percent[3] Direct + Indirect Section 10 Lease Tract Emissions
CO	334,632	239.0	1,031	0.4%
NO_x	175,321	1248.8	4,827	3.5%
PM_{10}	651,782	4089.6	99	0.6%
$PM_{2.5}$	134,879	432.5	40	0.4%
SO_2	152,506	1.4	8,916	5.8%
VOC	550,129	n/a	84	0.02%

Source:

USEPA FLIGHT tool (USEPA, 2018) and USEPA State Tier 1 Inventory (USEPA, 2017) for statewide emissions. Direct and indirect emissions are as presented in *Table 10* and *Table 11*

[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 Section 10 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 2016 results were measured. As emissions rates would be similar to existing operations but extended for seven months under the Proposed Action compared to the No Action, no significant cumulative impact to air quality would occur.

5.2.1.2 Greenhouse Gases and Climate Change

The EPA completes an annual inventory of greenhouse gases across the U.S. The most recent inventory shows a general trend of decreasing greenhouse gas emissions, with a 2.3 percent decrease from 2014 to 2015 (USEPA, 2017). In addition, 2015 emission levels were 10 percent below 2005 levels. The 2015 total U.S. greenhouse gas emissions equaled 6,587 million metric tons of carbon dioxide equivalents. Electricity generation was the largest source of these emissions, comprising 30 percent of the total, followed by transportation (27 percent), industry (21 percent), and agriculture (9 percent) (USEPA, 2017). The US Energy Administration tracks carbon dioxide emissions by sectors and by state. The 2015 total North Dakota carbon dioxide emissions was 57.1 million metric tons of carbon dioxide (USEIA, 2017), which represents a 2.6 percent decrease from 2014. Electricity generation is the largest source of carbon dioxide emissions in North Dakota comprising 52 percent of the total, followed by industry (28 percent), and transportation (16 percent). Direct emissions from the Proposed Action account for 0.2 percent of total carbon dioxide emissions from North Dakota and 0.0009% of carbon dioxide equivalents from the entire US. Indirect emissions from the Proposed Action account for approximately 19% of the total carbon dioxide emissions from North Dakota and approximately 0.1% of carbon dioxide equivalents from the entire US.

The EPA prepared a summary of available information regarding black carbon emissions. The 2005 total estimated black carbon emissions in the US was approximately 5.5 million tons. Black carbon emissions from the Proposed Action comprise less than 0.0004 percent of the total US annual black carbon emissions (USEPA, 2012).

Though total greenhouse gas emission levels from mining operations and emissions from Coal Creek Station and Spiritwood Station have been calculated for this EA (refer to *Table 10 Total Annual Direct Emissions* and *Table 6 Annual Greenhouse Gas Emissions at Coal Creek Station and Spiritwood Station 2012-2016*), 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. The rate of contribution to cumulative climate change, however, would be similar to the rate of existing operations under both the Proposed Action and the No Action. Emissions would be extended for seven months under the Proposed Action.

Chapter 6
Coordination and Consultation

6.1 Agencies and People Consulted

No additional people or agencies beyond those identified in Chapter 6.1 of the BLM EA[9] were consulted prior to and during the preparation of this Supplemental EA.

6.2 Preparers and Participants

Table 15 List of Preparers shows a list of the preparers of this Supplemental EA and those who participated in the preparation of this Supplemental EA from OSMRE.

Table 15 List of Preparers

Organization	Name	Title/ Project Responsibility
OSMRE	Gretchen Pinkham	Natural Resource Specialist/ Project Manager, internal scoping, review of Supplemental EA
OSMRE	Erica Trent	Natural Resource Specialist/MPDD Coordinator
OSMRE	Cecil Slaughter	Technical Reviewer

Table 16 Contractors shows a list of the preparers of this Supplemental EA and those who participated in the preparation of this Supplemental EA from the third party consultants Barr Engineering Co.

[9] The BLM EA is available on their eplanning website at: https://eplanning.blm.gov/epl-front-office/projects/nepa/67410/105731/129311/DOI-BLM-MT-C030-2016-0020-EA.pdf

Table 16 Contractors

Organization	Name	Title/ Project Responsibility
Barr Engineering Co.	Nadine Czoschke, PhD	Senior Environmental Scientist/Project Manager, Supplemental EA author
Barr Engineering Co.	Rachael Shetka	Senior Environmental Specialist/Supplemental EA author
Barr Engineering Co.	Amar Patel	Air Quality Scientist/Supplemental EA author

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Appendix A
Air Emissions Information

Emission Factors for Falkirk Mine 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	PM15	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	2.57	1.54	0.08	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

Emission Factors for Falkirk Mine Emissions Calculations (cont.)

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 of40 CFR Part 98—DefaultHigh Heat Values for Various Types of Fuel

Fuel type	HHV	Unit
Lignite	14.21	mmBtu/ton
Distillate Fuel Oil No. 2	0.14	mmBtu/gallon

Table C-1 and C-2 to Subpart C of40 CFR 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	1.531	1.72E-04	2.51E-05	1.54	ton/ton
Distillate Fuel Oil No. 2	73.96	3.00E-03	6.00E-04		kg/mmBtu
Distillate Fuel Oil No. 2	0.011	4.56E-07	9.13E-08	0.011	ton/gal

Global Warming Potential - Table A-1 40 CFR 98

Greenhouse gas	GWP
CO2	1
CH4	25
N2O	298

Emission Factors for Falkirk Mine Emissions Calculations (cont.)

Horsepower	Kilowatt	Fleet Vehicle Types	Model	Emission Standard	HC Exhaust (g/kw-hr)[a]	Ox 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]	CO_2 lb/hp-hr[b]	TOC lb/hp-hr[b]	Black carbon[c]
533	398	M. grader	24M	Tier 3	n/a	n/a	4	2.4	0.15	1.21E-05	1.08	12.555	0.1125
580	433	track dozer	D10T	Tier 3	n/a	n/a	3.7	2.8	0.16	1.21E-05	1.08	12.555	0.12
850	634	track dozer	D11T	Tier 2	n/a	n/a	5.7	0.9	0.06	1.21E-05	1.16	7.05	0.045
1969	1468	OB truck	789D	Tier 2	n/a	n/a	6.3	1.6	0.16	1.21E-05	1.16	7.05	0.12
2337	1743	OB truck	793D	Tier 2	n/a	n/a	7.9	1.1	0.18	1.21E-05	1.16	7.05	0.135
302	225	M. grader	16M	Tier 3	n/a	n/a	3.7	2.7	0.16	1.21E-05	1.08	12.555	0.12
600	447	scraper	657G	Tier 3	n/a	n/a	3.4	3.4	0.15	1.21E-05	1.16	7.05	0.1125
1463	1091	front end loader	994F	Tier 1	0.4	8.3	n/a	1.2	0.13	1.21E-05	1.16	7.05	0.0975
907	676	rt dozer & OB shovels	854K	Tier 2	n/a	n/a	5.4	0.9	0.06	1.21E-05	1.16	7.05	0.045
2100	1566	coal hauler	3516B	Tier 2	n/a	n/a	7.9	1.1	0.18	1.21E-05	1.16	7.05	0.135

[a] from engine manufacturer data

[b] from AP-42 Table 3.3-1 and Table 3.4-1

[c] Clean Air Task Force, 2009; Table 5. Assumption that 75% of diesel particulate matter is black carbon

Emission Factors for Falkirk Mine Emissions Calculations (cont.)

Permitted Emission Units Emission Limits at Falkirk Mine

Unit #	Description	Rate, ton/hr	Emission Limit, lb/hr PM
EU1	Truck dump	4000	1
EU2-3	NICO apron feeders	4000	2
EU4-5	Primary crushers	4000	2
EU6	72" conveyor	4000	1
EU7-8	Syntron MF-1000B Feeders	4000	2
EU9-10	Secondary crushers	4000	2
EU11	72" Silo feed conveyor	4000	1
EU12	Coal storage silo		
EU13	Cable Belt conveyor	1800	not operating

Particle size range	Fraction
PM10	0.75
PM2.5	0.03

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

Emissions Calculation Inputs for Falkirk Mine 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
Light vehicles	400,000	miles/yr	5	n/a	tons	Various	4.804	1.369	0.137	lb/vmt
Coal Haulers	830,000	miles/yr	461	200	tons	Kress 200C	36.786	10.486	1.049	lb/vmt
Cat End Dump Truck Fleet	3,200,000	miles/yr	518	190	tons	CAT 793D	38.763	11.049	1.105	lb/vmt
Miscelaneous	100,000	miles/yr	30	n/a	tons	Various	10.759	3.067	0.307	lb/vmt
Total	4,530,000	miles/yr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Annual Fuel Usage, 2012-2016

Year	Diesel Usage	Unit	CO_2	CH_4	N_2O	CO_2e	Unit
2012	8,216,759	gallons	92,444	4	1	92,668	tons
2013	7,638,060	gallons	85,934	3	1	86,141	tons
2014	7,930,836	gallons	89,228	4	1	89,443	tons
2015	8,238,261	gallons	92,686	4	1	92,910	tons
2016	7,717,800	gallons	86,831	4	1	87,041	tons
Total	39,741,716	gallons	447,123	18	4	448,204	tons

Annual VMT and diesel data provided by Falkirk Mining.

Blasting Emissions at Falkirk Mine

ANFO	Amount	Unit
2012	275,000.0	lbs
2013	225,000.0	lbs
2014	260,000.0	lbs
2015	260,000.0	lbs
2016	150,000.0	lbs
Total	1,170,000.0	lbs

Annual ANFO data provided by Falkirk Mining.

Year	CO	NO_X	SO_2	Unit
2012	4.6	1.2	0.14	TPY
2013	3.8	1.0	.011	TPY
2014	4.4	1.1	0.13	TPY
2015	4.4	1.1	0.13	TPY
2016	2.5	0.6	0.08	TPY
Annual	3.9	1.0	0.12	TPY

Calculation methodology for CO, NO_X, and SO_2 follows AP42, Chapter 13, Section 3.3, which provides an emission factor for pounds of pollutants per ton of ANFO combusted.

Falkirk Mine Total Mine Historical Emissions

Whole Mine Direct Fleet Emissions, Average of 2012-2016, tons

Equipment	NO_X	SO_X	CO	PM_{10}	$PM_{2.5}$
Hydraulic Shovels	48	0.1	8	0.5	0.5
Rubber Tire Dozers	19	0.0	3	0.2	0.2
Track Dozers (D10T)	55	0.1	42	2.4	2.4
Track Dozers (D11T)	139	0.2	22	1.5	1.5
F.E. Loaders	113	0.1	16	1.8	1.8
Motor Graders	74	0.1	45	2.8	2.8
Scrapers	40	0.1	40	1.8	1.8
Coal Haulers	450	0.4	63	10.3	10.3
OB Truck Fleet	1,200	1.1	167	27.3	27.3
Total	2,140	2.2	406	48.5	48.5

Whole Mine Fugitive Emissions, average of 2012-2016, tons

Fugitive Sources	PM_{10}	$PM_{2.5}$
Road Emissions	6,737	674
Truck Loading	7.8	0.2
Bull Dozing	127	4
Dragline	8.9	0.2
Grading	70	4
Active Storage Pile	0.8	0.8
Total	6,951.5	682.2

Average Emissions per Year Whole Mine, 2012-2016, tons

Pollutant	EU 1-11	Tailpipe emissions	Blasting	Fugitives	Total
NO_X	n/a	2,139.8	1.0	n/a	2,140.8
SO_X	n/a	2.2	0.1	n/a	2.4
CO	n/a	405.8	3.9	n/a	409.7
PM_{10}	10.7	48.5	n/a	6,951.5	7,010.7
$PM_{2.5}$	10.7	48.5	n/a	682.2	741.4
CO_2	n/a	89,424.6	n/a	n/a	89,424.6
CH_4	n/a	3.6	n/a	n/a	3.6
N_2O	n/a	0.7	n/a	n/a	0.7
CO_2e	n/a	89,640.8	n/a	n/a	89,640.8
Black carbon	n/a	36.4	n/a	n/a	36.4

Months	Coal Source
7	Section 10 coal
5	non-section 10 coal

Falkirk Mine Section 10 Federal Coal Direct Emissions

Section 10 Direct Fleet Emissions, tons

Equipment	NO_X	SO_X	CO	$PM_{2.5}$
Hydraulic Shovels	28	0.04	4.6	0.3
Rubber Tire Dozers	11	0.02	1.9	0.1
Track Dozers (D10T)	32	0.06	24.2	1.4
Track Dozers (D11T)	81	0.11	12.8	0.9
F.E. Loaders	66	0.06	9.6	1.0
Motor Graders	43	0.08	26.1	1.6
Scrapers	23	0.05	23.4	1.0
Coal Haulers	263	0.25	36.6	6.0
OB Truck Fleet	700	0.65	97.5	16.0
Total	1248	1.3	237	28

Section 10 Fugitive Emissions, tons

Fugitive Sources	PM_{10}	$PM_{2.5}$
Road Emissions	3,930.1	393.0
Truck Loading	4.5	0.1
Bull Dozing	74.0	2.2
Dragline	5.2	0.1
Grading	40.7	2.1
Active Storage Pile	0.4	0.4
Total	4,055.0	398.0

Total Direct Emissions

Pollutant	From Section 10 coal, tpy [A]	From non-Section 10 coal, tpy [B]	Total Falkirk mine coal, tpy [A+B]	Average Historical Falkirk Mine, tpy	Change in total Falkirk Mine emissions, tpy
NO_X	1,248.8	892.0	2,140.8	2,140.8	0
SO_X	1.4	1.0	2.4	2.4	0
CO	239.0	170.7	409.7	409.7	0
PM_{10}	4,089.6	2,921.1	7,010.7	7,010.7	0
$PM_{2.5}$	432.5	308.9	741.4	741.4	0
CO_2	52,164.3	37,260.2	89,424.6	89,424.6	0
CH_4	2.1	1.5	3.6	3.6	0
N_2O	0.4	0.3	0.7	0.7	0
CO_2e	52,290.4	37,350.3	89,640.8	89,640.8	0
Black carbon	21.2	15.2	36.4	36.4	0

Indirect Emissions from Combustion of Falkirk Mine Coal

Annual Indirect GHG Emissions based on coal combusted at Coal Creek Station and Spirit Wood, 2012-2016

Year	Coal Combusted	Unit	CO_2	CH_4	N_2O	CO_2e	Unit
2012	7,225,823	tons	11,060,356	1,245	181	11,114,323	tons
2013	6,927,877	tons	10,604,299	1,194	174	10,656,040	tons
2014	7,026,579	tons	10,755,379	1,211	176	10,807,858	tons
2015	7,211,153	tons	11,037,901	1,242	181	11,091,758	tons
2016	6,484,546	tons	9,925,705	1,117	163	9,974,135	tons
Average	6,975,196	tons	10,676,728	1,202	175	10,728,823	tons

Annual Total Indirect Emissions based on coal combusted at Coal Creek Station and Spirit Wood, 2012-2016

Year	Coal Combusted	Unit	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	TOC	Unit
2012	7,225,823	tons	194	78	16,272	8,655	1,807	145	tons
2013	6,927,877	tons	185	74	15,455	8,008	1,732	139	tons
2014	7,026,579	tons	193	77	15,865	8,042	1,836	144	tons
2015	7,211,153	tons	144	58	15,510	8,812	1,731	155	tons
2016	6,484,546	tons	134	54	13,317	7,857	1,731	140	tons
Average	6,975,196	tons	170	68	15,284	8,275	1,767	144	tons

Year	Coal Combusted	Unit	Hg	Se	Total Metals	Total HAP VOC	HCl	HF	H_2SO_4	Unit
2012	7,225,823	tons	0.40	0.02	6.61	3.12	0.75	79.00	21.50	tons
2013	6,927,877	tons	0.45	0.02	6.28	2.99	0.72	75.50	19.50	tons
2014	7,026,579	tons	0.45	0.02	6.79	2.99	3.42	75.80	69.60	tons
2015	7,211,153	tons	0.45	0.23	7.00	4.05	37.80	43.80	21.25	tons
2016	6,484,546	tons	0.17	0.20	5.98	3.59	34.85	39.70	17.55	tons
Average	6,975,196	tons	0.38	0.10	6.53	3.35	15.51	62.76	29.88	tons

Indirect Emissions from Combustion of Falkirk Mine Coal (cont.)

Annual Section 10 Coal combusted at Coal Creek Station and Spirit Wood Indirect Emissions, over life of project

Year	Coal Combusted	Unit	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC[a]	Unit
n/a	4,068,864	tons	99	40	8,916	4,827	1,031	84	tons

[a] Assumes TOC=VOC

Year	Coal Combusted	Unit	Hg	Se	Total Metals	Total HAP VOC	HCl	HF	H_2SO_4	Unit
n/a	4,068,864	tons	0.22	0.06	3.81	1.95	9.04	36.61	17.43	tons

Year	Coal Combusted	Unit	CO_2	CH_4	N_2O	CO_2e	Unit
n/a	4,068,864	tons	6,228,092	701	102	6,258,480	tons

Comparison of Direct and Indirect to North Dakota and US Emissions

All emissions in tons	2016 ND, from State Tier 1	Section 10 Direct	Section 10 Indirect	Section 10, % (Direct+Indirect)	Anticipated % change to State Emissions from Proposed Action
CO	334,632	239.0	1,031	0.4%	0%
NO_x	175,321	1248.8	4,827	3.5%	0%
PM_{10}	651,782	4089.6	99	0.6%	0%
$PM_{2.5}$	134,879	432.5	40	0.4%	0%
SO_2	152,506	1.4	8,916	5.8%	0%
VOC	550,129	n/a	84	0.02%	0%

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	CO_2e	% of ND	% of US	Black carbon[a]	% of ND	% of US
North Dakota Total	33.6			0.003		
US Total	5,764			5.5		
Section 10 Direct	0.05	0.2%	0.0009%	2.12E-05	0.8%	0.0004%
Section 10 Indirect	6.3	19%	0.1%			

Data Extracted from EPA's FLIGHT Tool (http://ghgdata.epa.gov/ghgp)

[a] Clean Air Task Force, 2009; Table 5. Assumption that 75% of diesel particulate matter is black carbon