Southern Ute Indian Tribe

Priority Climate Action Plan

April 1, 2024

Southern Ute Indian Tribe Air Quality Division

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This project has been funded wholly or in part by the United States Environmental Protection Agency (EPA) under assistance agreement 5D-00133400 to the Southern Ute Indian Tribe Air Quality Division. The contents of this document do not necessarily reflect the views and policies of the EPA, nor does the EPA endorse trade names or recommend the use of commercial products mentioned in this document.

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Abbreviations

AQ Planner	Air Quality Planner
AQD	Air Quality Division
AQDH	Air Quality Division Head
AQDM	Air Quality Division Manager
AQTM	Air Quality Technical Manager
ASAP	as soon as possible
CAA	Clean Air Act
CAPs	Criteria Air Pollutants
CARB	California Air Resources Board
CCAP	Comprehensive Climate Action Plan
CFR	Code of Federal Regulations
CH_4	methane
CMS	compliance monitoring strategy
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
Commission	Southern Ute Indian Tribe and State of Colorado Environmental Commission
Cottonwood	Cottonwood Consulting LLC
CPRG	Climate Pollution Reduction Grant
CY	Calendar Year
DOE	Department of Energy
EI	emissions inventory
EPA	US Environmental Protection Agency
EV	electric vehicle
FIP	Federal Implementation Plan for Managing Air Emission from True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Gas Sector
FLIGHT	Facility Level Information on Greenhouse Gases Tool
FY	fiscal year
GAP	General Assistance Program
GC	Grants Coordinator
GHG	Greenhouse Gas
HAPs	Hazardous Air Pollutants
HFCs	hydrofluorocarbons
IRA	Inflation Reduction Act
LDAR	Leak Detection and Repair
Lidar	Light Detection and Ranging
MACT	Maximum Achievable Control Technology
MERP	Methane Emissions Reduction Program
MM	millions
MW	megawatt

N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NF_3	nitrogen trifluoride
NO_x	nitrogen
NSPS	New Source Performance Standards
PCAP	Priority Climate Action Plan
PFCs	perfluorocarbons
$PM_{2.5}$	particulate matter 2.5 micrometers or less in diameter
PM_{10}	particulate matter 10 micrometers or less in diameter
PTE	potential to emit
QAPP	Quality Assurance Project Plan
RAC	Reservation Air Code
Red Cedar	Red Cedar
Red Willow	Red Willow Production Company
Reservation	Southern Ute Indian Reservation
SAQCS	Senior Air Quality Compliance Specialist
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
TBD	to be determined
TIP	Tribal Implementation Plan
TMNSR	Tribal Minor New Source Review
tpy	tons per year
Tribe	Southern Ute Indian Tribe
VOC	volatile organic compounds

1 Executive Summary

The purpose of this Priority Climate Action Plan (PCAP) is to provide a comprehensive and detailed analysis of the short-term, high-priority, and implementation ready greenhouse gas (GHG) emissions reductions measures that could be implemented by the Southern Ute Indian Tribe (Tribe) Air Quality Division (AQD) within the boundaries of the Southern Ute Indian Reservation (Reservation; see Figure 1).

The primary priority measure being considered in the PCAP is the Tribe's proposal to reduce GHG and volatile organic compound (VOC) emissions from minor sources of oil and gas on the Reservation through the Tribe's voluntary administration and implementation of several Clean Air Act (CAA) programs and standards.

The voluntarily administered CAA programs would be the Federal Minor New Source Review Program in Indian country, 40 CFR Part 49, Subpart C, Sections 49.151 through 49.164 (TMNSR), and the Federal Implementation Plan for Managing Air Emissions from True Minor Sources in Indian Country in the Oil and Natural Gas Production and Oil and Natural Gas Processing Segments of the Oil and Natural Gas Sector, 40 CFR Part 49, Subpart C, Sections 49.101 through 49.105 (FIP).

The voluntarily implemented standards are the New Source Performance Standards (NSPS) Subparts OOOO, OOOOa, and OOOOb. These standards were promulgated by the US Environmental Protection Agency (EPA) to establish standards designed to reduce GHG and VOC emissions from the oil and gas sector. Lastly, the Tribe is proposing the development and EPA approval of a Tribal Implementation Plan (TIP) for adoption of the Emissions Guidelines established in NSPS OOOOc.

The PCAP outlines the data collection methodology and analyses used to identify the emissions sources of interest within the Reservation and a mitigation plan that could be implemented to reduce emissions of GHG, and the co-benefit pollutant, VOCs through the Tribe's voluntary administration and implementation of these CAA programs and standards.

The Tribe's PCAP will focus on the industrial sector, as identified in the Climate Pollution Reduction Grant (CPRG), and specifically, the oil and gas sector. The industrial sector on the Reservation includes two landfills, and nearly 3,000 oil and gas sources ranging from small oil and gas pads to large gas processing facilities. Collectively, oil and gas sources are the largest emitters of GHG, VOC, hazardous air pollutants (HAPs), and criteria air pollutants (CAPs), on the Reservation.

For the purposes of the PCAP, emissions data will be sourced from the AQD's existing calendar year (CY) 2020 comprehensive emissions inventory, which includes emissions data from every source sector on the Reservation including "major" and "minor" oil and gas and landfill point sources, nonpoint oil and gas and landfill sources, mobile sources, wildfires, residential heating, airports and aviation fueling, biogenic sources, and natural occurring methane emissions from the Fruitland Coal outcrop. Reservation-wide emission totals for CY 2020 were 11,342,510.62 metric tons of GHG emissions measured in carbon dioxide equivalent (CO_2e), 8,773.01 tons of VOCs,

19,743.58 tons of oxides of nitrogen (NO_x), 80.94 tons of sulfur dioxide (SO_2), 396.57 tons of particulate matter 10 micrometers or less in diameter (PM_{10}), 146.02 tons of particulate matter 2.5 micrometers or less in diameter ($PM_{2.5}$), 18,767.33 tons of carbon monoxide (CO), and 1,527.28 tons of total HAP.

Minor oil and gas point sources are the focus of this PCAP, because this source category is currently the third most significant source of GHG emissions on the Reservation at 1,568,843 metric tons per year (tpy) of CO_2e, and the most significant source category subject to federal CAA permit programs (TMNSR and the FIP) which could be administered by the Tribe through an EPA delegation. Title V major oil and gas sources are the largest source of GHG emissions on the Reservation at GHG at 2,124,765 tpy of CO_2e, and sources below the TMNSR and FIP program thresholds are the second largest GHG emitters at 1,618,204 tpy CO_2e. Title V major sources and sources below TMNSR and FIP program thresholds are not being considered in this PCAP because the Tribe has previously implemented measures to reduce emissions from these sources, including voluntary administration of CAA programs to regulate these sources, or because the sources are not subject to federal CAA permit programs, and are therefore not easily regulated by the Tribe. A 2012 EPA rulemaking provided the Tribe with a full delegation of the Title V operating permit program, implementation of the NSPS, National Emissions Standards for Hazardous Air Pollutants (NESHAP) and Maximum Achievable Control Technology (MACT) standards. A 2013 EPA rulemaking granted the Tribe automatic delegation of the standards under CAA §§111 and 112.

The Tribe's efforts to administer the TMNSR program and FIP are well underway, with the Tribe having applied to EPA in April of 2020 requesting conditional approval for administrative delegation of the TMNSR permitting program and FIP. The Tribe and EPA are currently nearing completion of a delegation agreement between the Tribe and the EPA for these programs and it's a goal of EPA to publish a rulemaking in 2024 to make the agreement final.

The decision for the Tribe to apply for delegation of the TMNSR and FIP followed an extensive stakeholder outreach process from 2017 through 2019, which included the regulated community, the public, and other governmental agencies, including La Plata County, Archuleta County, the State of Colorado, EPA, and Tribal Council. This process entailed numerous public meetings tailored towards regulated industry and multiple public Tribe/State of Colorado Environmental Commission (Commission) meetings to evaluate the project options with all interested parties and stakeholders.

Central to the Tribe's PCAP priority measure is the Tribe's plan to assess compliance with the TMNSR, FIP, and NSPS OOOO series rules through increased compliance oversight of the approximately 250 true minor oil and gas sources and six synthetic minor oil and gas sources on the Reservation. The Tribe is certain, due to its previous experience implementing CAA programs and standards, that these activities would lead to increased compliance, and in turn, a reduction of GHG, VOC, and other harmful air pollutants. Under the Tribe's proposal, true minor sources (e.g. FIP sources) would be inspected on a five-year basis and synthetic minor sources (e.g. TMNSR sources) would be inspected on a two-year basis through an EPA-approved compliance monitoring strategy (CMS). Under the current EPA administration of the TMNSR program and FIP, true minor sources are not inspected, and synthetic minor sources are inspected once every five years.

The Tribe's proposed inspection frequency is consistent with the CMS inspection frequency of the State of Colorado and New Mexico air quality jurisdictions adjacent to the Reservation.

In addition, the Tribe plans to investigate oil and gas sources identified in the Tribe's emissions inventory that may be operating above TMNSR or Title V operating permit program emission thresholds without a federal or Tribal permit. The Tribe will work to get these sources into compliance through the Tribe's existing CAA authorities under 40 CFR Part 49 and Part 70, and CAA §§§§111, 112, 113 and 114.

Furthermore, the Tribe intends to evaluate and include in the PCAP, the Comprehensive Climate Action Plan (CCAP), and emissions inventories potential emissions reductions that may result from several projects and emissions quantifications activities being undertaken on the Reservation by the Tribe's business entities and non-Tribal private industry. These projects are further described below in Sections 4.2 and 4.6.

All activities completed under the CPRG will (1) be the responsibility of the Tribe's AQD as the lead agency, (2) be performed within the exterior boundaries of the Reservation in southwest Colorado and (3), begin in CY 2025 and implemented through the end of the grant cycle in CY 2030.

To demonstrate the GHG and co-pollutant emissions reductions that could be realized through the PCAP measures, the Tribe has estimated emissions projections and reduction targets from CY 2025 through CY 2050. To make this demonstration, the Tribe began by projecting emissions forward based on a per facility emissions estimate, determined using the CY 2020 emissions inventory report, and applying a target GHG reduction of 29 percent (%) from a report developed by the California Air Resources Board (CARB) titled "*CARB's Oil and Gas Methane Regulation 2018 Annual LDAR Summary*" which estimates GHG emission reductions resulting from implementation of leak detection and repair programs in California. The Tribe has estimated that one true minor source has a potential to emit (PTE) 520.67 CO_2e metric tons per year. Between the years of 2025 and 2030, the AQD expects to reduce GHG emissions from minor oil and gas sources by approximately 247,482 metric tons of CO_2e. The Tribe has estimated that 4.3 new minor sources will be developed every year through 2050 and that the PCAP priority measure will reduce GHG emissions from true minor sources by approximately 654.3 metric tons per year. The AQD also estimates similar reductions from the six synthetic minor sources; however, for simplicity, these sources are being grouped into the true minor source category, despite them being larger sources with potentially higher emissions and possible emission reductions.

The Tribe's voluntarily administration of these CAA programs and standards and the accompanying compliance strategy would result in significant improvements to the Tribe's air shed and reduce the impacts of climate change caused by GHG emissions. This will, in turn, help mitigate several potential impacts of climate change that are currently observed on the Reservation (such as increased droughts and forest fires) and will significantly reduce climate change impacts for future generations.

If the Tribe is successful in obtaining these EPA delegations, it would be the first instance of a federally recognized Tribe in the United States to voluntarily receive TMNSR and FIP delegation

and to implement a minor source inspection schedule that will ensure compliance at regulated and potentially unregulated polluting sources on a Reservation. In addition, this delegation will improve the Tribe's understanding of emissions sources on the Reservation and enhance emissions data collection from these sources. This delegation will also provide other federally recognized tribes an example that can be used to seek delegation of the TMNSR programs and FIP from EPA in their own jurisdictions.

2 Introduction

The Reservation is located in the southwestern region of Colorado bordering the state line of New Mexico. This semi-arid and high desert landscape is vulnerable to the effects of climate change and warmer temperatures. An increase in wildfires, droughts, and excessive heat waves are just a few of the harmful impacts felt by Tribal members, local residents, and the environment. To mitigate these effects, the Tribe applied for and received a Climate Action Planning Grant to develop a long-term strategy to reduce the effects of climate change by decreasing GHG emissions within the exterior boundaries of the Reservation.

The Tribe is dedicated to ensuring that the air on the Reservation remains clean and safe for Tribal members and residents, now and into the future. The Tribe does this through monitoring of air quality, CAA permitting and compliance monitoring of major air pollution sources, emissions inventories, and continued research of air pollution and its sources. By reducing GHG and other harmful air pollutant emissions, the Tribe will reduce the harmful effects of climate change related to global temperature rise and improve air quality for Tribal members, residents of the Reservation, and the environment.

The Tribe has developed this PCAP to address near-term, high-priority, implementation-ready measures to reduce GHG and VOC emissions on the Reservation. The PCAP is focused on the oil and gas (industrial) sector, which is the highest-emitting sector on the Reservation.

As outlined in the Executive Summary, the Tribe proposes to reduce GHG emissions on the Reservation through the Tribe's voluntary administration and implementation of several CAA programs and standards.

Furthermore, the Tribe intends to describe potential GHG emissions reductions projects that may be undertaken by Tribal business entities (separate from Tribal government) and non-Tribal private industry.

Based on data from the EPA's Environmental Justice Screening and Mapping Tool, EJScreen, the Reservation and Tribal members are an environmental justice population. Creation of high-quality jobs in environmental justice populations is a high priority of EPA and the Tribe. The Tribe is dedicated to being a premier employer in the southwestern region of Colorado. The Tribe offers competitive wages and a significant employee benefits package that includes paid holidays, health insurance, annual and sick leave accrual, dental, vision, life insurance, and retirement plans for full-time employees (further discussed in section 4.7).

2.1 Climate Pollution Reduction Grant Overview

Through the Inflation Reduction Act of 2022 (IRA), Congress provided many tools to pursue GHG pollution reductions, including the CPRG program. In implementing this and many other programs under the IRA, the EPA seeks to achieve three broad objectives:

- Tackle damaging climate pollution while supporting the creation of good jobs and lowering energy costs for families.
- Accelerate work to address environmental injustice and empower community-driven solutions in overburdened neighborhoods.
- Deliver cleaner air by reducing harmful air pollution in places where people live, work, play, and go to school.

In line with this strategy, EPA is committed to supporting the development and expansion of tribal, state, territorial, and local climate action plans, and the implementation of investment-ready projects to reduce GHG pollution.

2.2 Priority Climate Action Plan Overview

The Tribe received a CPRG planning grant award in 2023 and is utilizing that award to develop a PCAP. The planning grant provides flexible support to design climate action plans that incorporate a variety of measures to reduce GHG emissions from across their economies in key sectors.

The PCAP will help the Tribe to:

1. Improve their understanding of current and future GHG and other harmful pollutant emissions,
2. Identify priority strategies to reduce these emissions and the potential other benefits of those strategies, and
3. Engage stakeholders in an emissions reduction planning process, including development of the CCAP.

Development of the PCAP will also support the Tribe's CPRG implementation grant application and will inform the CCAP, which is due at the close of the grant period (CY 2030).

The PCAP includes the elements listed below:

- GHG inventory.
- Analysis of GHG emissions reductions that would be achieved through implementation of the proposed GHG reduction measure.
- Benefits analysis.
- A review of the Tribe's authority to implement the proposed GHG reduction measure.

2.3 Approach to Developing the PCAP

Multiple approaches and methodologies have been used to develop this PCAP, including leveraging of the expertise and technical capacities at the Tribe’s disposal.

The Tribe prepares emissions inventories for air emission sources within the Reservation boundaries. Comprehensive inventories of emissions from all quantifiable point, nonpoint sources,

mobile, and fire events are completed every three years and inventories of large point source emissions are completed annually. The emissions inventory utilized by the PCAP was developed for CY 2020 emissions.

Based on the results of the 2020 Emissions Inventory (2020 EI), the oil and gas sector is the highest-emitting sector on the Reservation and minor oil and gas sources are the third largest emitters within the sector. The Tribe sought to develop GHG reduction measures that would reduce emissions from oil and gas facilities. The Tribe prioritized measures that are ready for implementation and for which the Tribe will have the authority to implement.

The Tribe engaged stakeholders and the public in other, closely related projects. Additionally, the Tribe met with stakeholders early in the CPRG planning grant process to develop an understanding of other GHG reduction measures and projects underway on the Reservation.

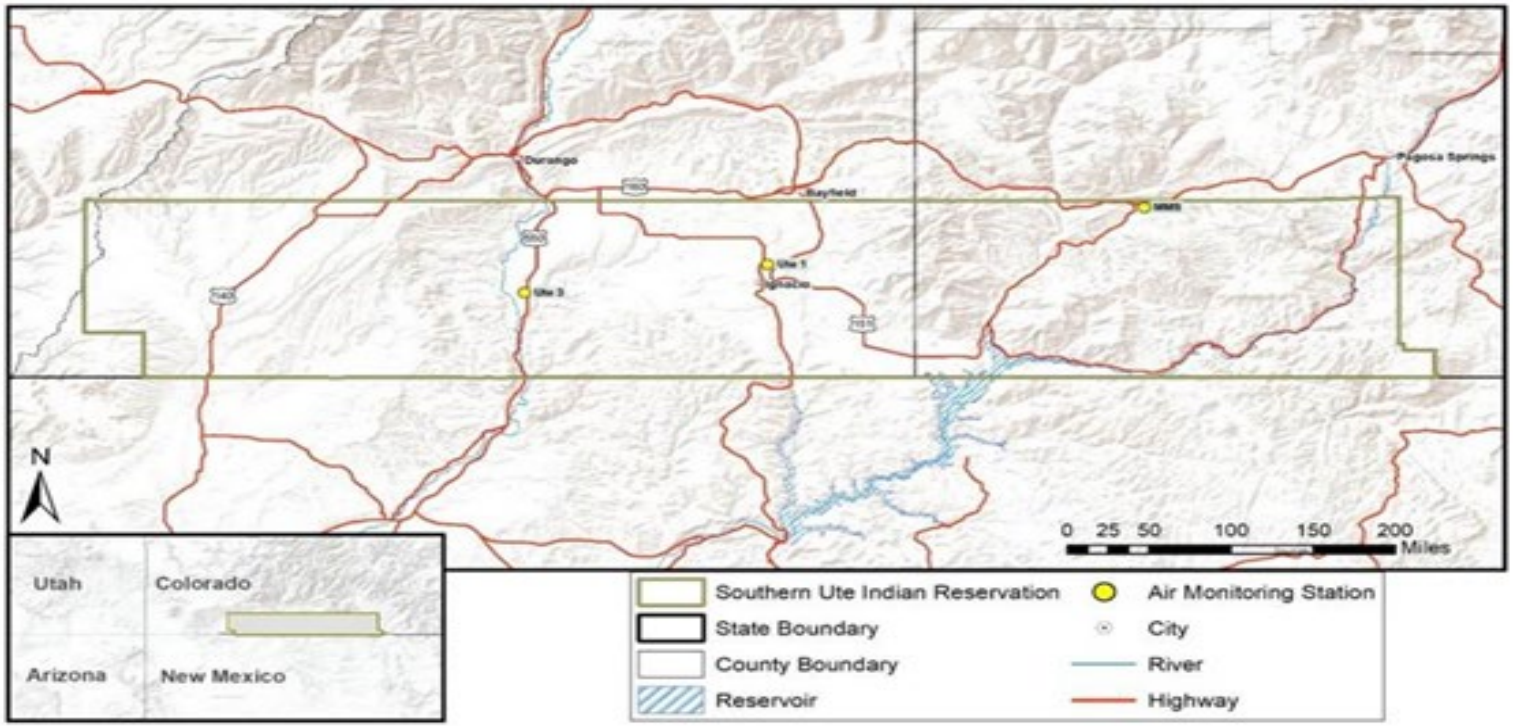
2.4 Scope of the PCAP

All lands located within the exterior boundaries of the Reservation are under the jurisdiction of the Reservation Air Program, which was established in 2004 by the Intergovernmental Agreement between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation (Pub. L. No. 108-336, 118 Stat. 1354). The Reservation Air Program is under the oversight of the Commission, which serves as the policy-making and administrative review authority for the Reservation Air Program.

The Reservation is located in southwestern Colorado and covers 682,590 acres in three counties (La Plata, Archuleta, and Montezuma), bordering New Mexico to the south (Figure 1). The Tribe and/or its members own approximately 320,000 acres, while the remaining land is comprised of non-Indian and government land in a checkerboard fashion. The primary land use is agricultural, and the predominant industry is oil and natural gas production.

All GHG emissions reduction activities proposed in the PCAP will be performed within the exterior boundaries of the Reservation.

Figure 1. Southern Ute Indian Reservation



3 Tribal Organization and Considerations

The AQD is a division of the Environmental Programs Department of the Southern Ute Tribal Government. The Southern Ute Indian Tribal Council is the governing body of the Tribal Government, as established by the passage of the Indian Reorganization Act by Congress.

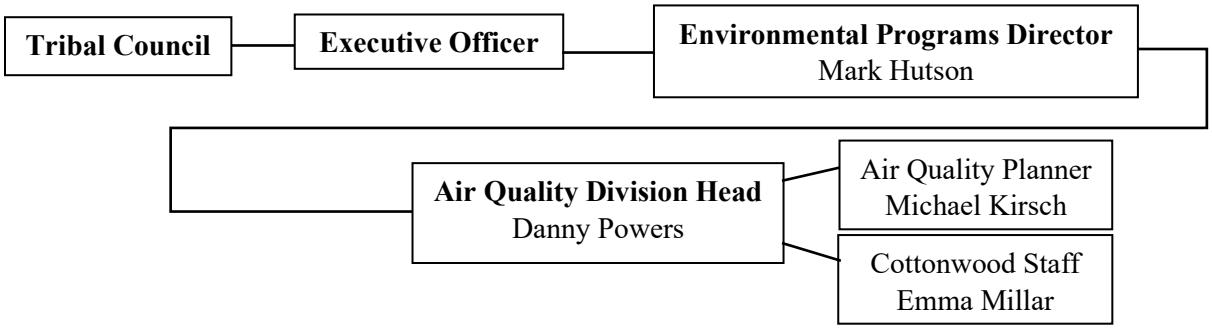
The AQD's staff positions include an Air Quality Division Head (AQDH), two Air Quality Division Managers (AQDMs), an Air Quality Planner (AQ Planner), three Air Quality Compliance Specialists, a Permit Writer, an Enforcement Coordinator, and an Ambient Air Quality Specialist.

3.1 PCAP Management and Development Team

The PCAP was prepared at the direction of Tribal Council by AQD staff with assistance from a consultant, Cottonwood Consulting LLC (Cottonwood), who was contracted to assist the AQD with the development of planning grant deliverables, including a quality assurance project plan (QAPP), the PCAP, and the CCAP.

A PCAP development organization chart is included as Figure 2.

Figure 2. PCAP Development Organization Chart



3.2 Special Considerations

The Tribe currently implements and administers a Title V operating permit program (EPA 40 Code of Federal Regulations [CFR] Part 70) for Title V sources within the exterior boundaries of the Reservation. To further improve air quality on the Reservation, the Tribe has requested EPA authority to implement and administer the TMNSR program and FIP on the Reservation. This authority will allow the Tribe to regulate approximately 250 true minor oil and gas sources and six synthetic minor sources within the Reservation. These sources are currently permitted and inspected by the EPA; however, the EPA has been unable to conduct compliance inspections at true minor sources due to resource constraints, and the six synthetic minor sources are only inspected on a five-year basis. The Tribe anticipates that administering these programs, including issuance of permits and conducting inspections, will result in higher levels of compliance with applicable regulations and a subsequent reduction in GHG and VOC emissions.

3.3 Collaborations

From 2017 through 2019, the Tribe undertook an extensive stakeholder outreach process to determine the best option for the Tribe's regulation of minor oil and gas sources within the Reservation boundaries. The stakeholders included the regulated community, the public, and other

governmental agencies, including La Plata County, Archuleta County, the State of Colorado, EPA, and Southern Ute Tribal Council. This process entailed numerous public meetings tailored towards the regulated industry and multiple public Commission meetings to evaluate the project options with all interested parties and stakeholders.

For the purpose of the CPRG, the AQD includes agenda item discussions at the bi-annual Commission meetings, and will conduct additional public stakeholder meetings as warranted, to discuss proposed and additional measures that could be taken to reduce GHG emissions. These Commission agenda item discussions and public meetings provide the opportunity for stakeholders to offer input on how to meet the PCAP and CCAP goals most effectively, including additional potential GHG reduction measures on the Reservation from source sectors other than oil and gas. Discussions also include ideas of how to develop quality GHG emission inventories and the sharing of draft items being prepared for the CPRG implementation phase. The Tribe also engages with oil and gas operators and energy development companies on the Reservation to quantify their emission reduction measures in the Tribe's emissions inventories.

All Commission meeting announcements, draft agendas, and final documents are available on the Tribe's AQD websites and published in local newspapers, when necessary. Virtual meeting options are provided to the public and stakeholders for all in-person meetings. The next Commission meeting is scheduled for April 24, 2024.

Following receipt of the CPRG planning grant, the AQD also met with other entities, including Red Willow Production Company (Red Willow), Red Cedar Gathering Company (Red Cedar), Department of Energy (DOE), and Aka Energy Group, that operate on the Reservation and are implementing emissions reduction projects on the Reservation. Some information about those projects is included in 4.2.2 and more detail will be included in the CCAP.

In addition to Commission meetings and coordination with other entities, the Tribe has solicited feedback from Tribal members, Tribal employees, and residents of the Reservation via a survey linked to the Tribe's AQD website. The survey consists of a series of questions related to GHG emissions and proposed GHG reduction measures. The survey also includes a comment section to solicit other input. Results and analysis of the survey results will be included in the CCAP. Based on the feedback received from that survey, the Tribe may conduct virtual or in-person meetings to solicit additional public input. The Tribe may also host webinars or in-person meetings to explain proposed GHG reduction measures.

For the purposes of increasing public knowledge of the CPRG, soliciting input on PCAP and CCAP developing, and posting draft and final documents, a new CPRG webpage has been developed by the Tribe. This website includes information about the CPRG and PCAP/CCAP development, and a link to the aforementioned survey to allow the public to actively participate in the planning process. All documents related to the CPRG will be posted once finalized and approved by EPA and the Tribe.

4 PCAP Elements

Section 4 includes a GHG inventory, a list of implementation-ready measures to reduce GHG pollution, an analysis of GHG emissions reductions, a benefits analysis, and a review of the Tribe's authority to implement to proposed GHG reduction measure.

4.1 GHG Inventory

The GHG inventory included in the PCAP was compiled using existing data derived from the Tribe's Comprehensive Emissions Inventory developed for CY 2020 and is included as Appendix A. The 2020 EI was developed to determine emissions estimates for all quantifiable air emission sources located within the Reservation's exterior boundary. The emissions data presented in the 2020 EI have been organized by source category and pollutant. The 2020 EI is used for air quality planning purposes, including development of air quality regulations targeted at ozone precursors for maintaining attainment with the National Ambient Air Quality Standards (NAAQS), emissions modeling, Title V permitting fee analysis, and to monitor GHG emissions within the Reservation.

4.1.1 Scope

The geographic scope of the 2020 EI is the exterior boundary of the Reservation. The total area covered by the inventory is approximately 682,590 acres, which encompasses all land within the external boundaries of the Reservation.

The primary air pollutants included in the 2020 EI are NO_x, CO, PM_{10}, $PM_{2.5}$, VOC, HAP, and GHG emissions (carbon dioxide [CO_2], methane [CH_4], nitrous oxide [N_2O], hydrofluorocarbons [HFCs], perfluorocarbons [PFCs], sulfur hexafluoride [SF_6], and nitrogen trifluoride [NF_3]) measured in CO_2e. The emissions inventory was prepared according to the EPA Level II emission inventory guidelines of using measured data when available or data and emissions factors from reputable sources when measured data were not available.

4.1.2 Data Collection

The sources included in this emissions inventory were organized according to source type and size. These sources are as follows:

A. Point Sources
    1) Title V permitted oil and natural gas sources,
    2) TMNSR minor oil and natural gas sources, including:
        a. Permitted minor TMNSR sources
        b. Registered minor FIP sources
    3) Municipal solid waste landfills, and
    4) Airports.
B. Non-point Sources
    1) Small oil and gas sources,
    2) Fruitland Coal Outcrop natural gas seeps,
    3) Gasoline stations,
    4) Aviation gasoline dispensing,
    5) Gravel pits,
    6) Residential heating, and

7) Agricultural burning.

C. Mobile Sources
   1) On-road vehicles, and
   2) Non-road equipment.

D. Events
   1) Fire events (wildland fires and prescribed burns).

Oil and natural gas production is the dominant industry on the Reservation and oil and gas sources were identified as the primary source of GHG emissions on the Reservation. Emissions data for these sources were collected directly from source operators through annual emission inventories, registrations from sources under the EPA-administered TMNSR program, and a CAA Section 114 information collection request issued by the Tribe in June 2021. Data for other sources were collected from various reputable state, local, and federal data sources such as the Motor Vehicle Emission Simulator, Landfill Gas Emissions Model, and Facility Level Information on GreenHouse gases Tool (FLIGHT) tools developed by the EPA. More detail about data collection and data quality are included in the 2020 EI.

The 2020 EI inventory also covers emissions from landfills, nonpoint sources, mobile sources, wildfires, biogenic sources, and naturally occurring natural gas emissions from the Fruitland Coal geologic outcrop. Nonpoint sources include agricultural burning, residential heating, gravel pits, gas stations, and airports. Airport emissions include emissions from landing, take-off, and aviation fueling. Mobile sources include on-road vehicles and non-road engines including lawn equipment, recreational vehicles, agricultural equipment, construction equipment, etc.

4.1.3 GHG Accounting Method

Title V sources are required to report emissions annually and pay a per-ton emission fee for pollutants emitted. Emissions data for Title V sources were collected directly from the operators through required emission reports submitted by each source to the Tribe. Actual emissions data were available for all 35 Title V oil and gas sources. GHG emissions, reported as CO_2e, were obtained from fee calculation worksheets (if provided) and if not, the PTE listed in their most recent Title V permit renewal was used and cross checked with EPA FLIGHT at https://GHGdata.epa.gov/GHGp/main.do. Data for minor oil and gas sources were collected directly from source operators through registrations from sources under the EPA-administered TMNSR program and FIP. Data for oil and gas sources below the emission thresholds of the TMNSR and FIP programs were obtained using a CAA Section 114 information collection request issued by the Tribe in June 2021. The Tribe used this information to calculate emissions using actual production data from the Reservation and the best available emissions factors and assumptions. This data collection and calculation methodology adheres to the EPA Level II EI guidelines for utilizing measured data when available and the best available emissions factors and assumptions when measured data is not available.

4.1.4 GHG Emission Results by Sector- Oil and Gas

As of 2020, there were a total of 2,860 oil and gas production sources operating on the Reservation. These sources consisted of 35 sources operating under Tribe-issued Title V operating permits, six sources operating under EPA TMNSR synthetic minor permits, 238 true minor sources operating

under EPA FIP registrations, and 2,582 non-point sources with emissions below the TMNSR and FIP program thresholds, referred to in the 2020 EI as "small oil and gas sources."

Reservation-wide emission totals for CY 2020 were 19,743.58 tons of NO_x, 8,773.01 tons of VOC, 80.94 tons of SO_2, 396.57 tons of PM_{10}, 146.02 tons of $PM_{2.5}$, 18,767.33 tons of CO, 1,527.28 tons of total HAP, and 11,342,510.62 metric tons of GHG emissions measured in CO_2e.

4.2 GHG Reduction Measure – Voluntary Administration and Implementation of CAA Programs and Standards

The Tribe has demonstrated through several emissions inventories that the oil and gas industry is the most significant source of GHG and other air pollution on the Reservation. The Tribe anticipates oil and gas production and development to continue on the Reservation, and within the greater Four Corners region, for several more decades. For this reason, it is an important function of the Tribe to make efforts to mitigate these emissions in an environmentally and economically efficient manner. To mitigate these emission impacts, the Tribe has developed a GHG reduction measure that will have significant and lasting reductions in GHG emissions on the Reservation, which will result in associated climate and health benefits.

The GHG reduction measure being proposed by the Tribe is the Tribe's voluntary administration and implementation of several CAA programs and standards, including (1) the TMNSR program; (2) the minor oil and gas source FIP; (3) implementation of the NSPS OOOO, OOOOa, and OOOOb standards through the Tribe's existing NSPS authority; and (4) development of a TIP to adopt the Emissions Guidelines of NSPS OOOOc. Compliance with all of these measures will be verified through the compliance and enforcement activities and strategies listed below.

The Tribe, through nearly 15 years of successful administration of CAA programs for major sources and a highly developed and experienced compliance and enforcement program, anticipates that the Tribe's voluntary administration and implementation of these listed CAA programs and standards at minor sources on the Reservation will result in significantly increased compliance and reduced emissions. Central to this assessment is the Tribe's proposal for increased compliance oversight of the approximately 250 true minor oil and gas sources and six synthetic minor oil and gas sources on the Reservation. Under the Tribe's proposal, true minor sources would be inspected on a five-year basis and synthetic minor sources on a two-year basis, through an EPA-approved CMS. Under the current EPA administration of the TMNSR program and FIP, true minor sources are not inspected, and synthetic minor sources are inspected every five years. The Tribe's proposed monitoring frequency is consistent with the CMS inspection frequency of the State of Colorado and New Mexico air quality jurisdictions adjacent to the Reservation.

In addition to inspecting known oil and gas minor sources, the Tribe plans to investigate sources identified in the Tribe's emissions inventory that may be operating above TMNSR, FIP, or Title V operating permit program emission thresholds without a federal or Tribal permit. The Tribe will work to get these sources into compliance through the Tribe's existing CAA authorities under 40 CFR Part 70, and CAA §§§§111, 112, 113 and 114, and, once delegated, through the TMNSR and FIP authorities of 40 CFR Part 49.

The Tribe anticipates that GHG emissions from minor oil and gas sources on the Reservation could be reduced by approximately 29% each year through the Tribe's priority measure of voluntary administration and implementation of CAA programs and standards and realized through implementation of an EPA-approved CMS. This estimation is based on a CARB report titled "*CARB's Oil and Gas Methane Regulation 2018 Annual LDAR Summary*", which found that leak detection and repair (LDAR) inspections reduced GHG emissions from leaking components and valves by 29% (see Section 4.3) The CARB report is included as Appendix B. Table 1 provides a more detailed list of these project components.

Table 1: Components of the Tribe's Priority Measure for Reducing GHG Emissions

Components of the Tribe's Priority Measure for Reducing GHG Emissions	
Component	**Summary**
Tribal Minor New Source Review (TMNSR)	• TMNSR is a preconstruction permit program that serves two purposes. The first is to ensure that air quality is not significantly degraded by the addition or modification of new sources. The second assures people that any large new or modified industrial source in their neighborhoods will be as clean as possible, and that advances in pollution control occur concurrently with industrial expansion. • Tribe has outlined a delegation agreement between EPA and the Tribe to voluntarily obtain authority of the TMNSR program. Delegation is anticipated to be finalized by the end of CY 2024.
Federal Implementation Plan (FIP)	• FIP is an air quality plan developed by EPA under certain circumstances to help states or tribes attain and/or maintain the NAAQS for criteria air pollutants and fulfill other requirements of the CAA. • New or modified true minor new source review oil and gas sources in Indian Country may obtain coverage to construct under the FIP, codified at 40 CFR 49. • The FIP incorporates by reference several NSPS and MACT rules, including NSPS OOOO. • The Tribe has outlined a delegation agreement between EPA and the Tribe to voluntarily obtain authority of the FIP program. • Delegation is anticipated to be finalized by the end of CY 2024.
New Source Performance Standards (NSPS) Subpart OOOO – Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Facilities	• The NSPS OOOO series rules, include OOOO, OOOOa and OOOOb, established emissions standards for GHG and VOC in the oil and gas sectors. These include standards for leaking components and LDAR programs. The Tribe has existing CAA authority to implement the OOOO & OOOOa standards and plans to adopt OOOOb in the fall of 2024.
Tribal Implementation Plan (TIP)	• An air quality plan developed by a tribe to help attain and/or maintain NAAQS for CAPs and fulfill other requirements of the CAA. • Unlike states, tribes are not required to adopt an implementation plan. • EPA established Emissions Guidelines under section 111(d) of the CAA for GHGs emissions (in the form of methane limitations) from existing sources (designated facilities) under the new NSPS OOOOc rule. • The Tribe is proposing to develop a TIP for adopting the Emissions Guidelines established in the NSPS OOOOc rule.

To increase tribal sovereignty and expand upon the Tribe's current authority to implement the NSPS, the Tribe will propose a rulemaking through the Commission to adopt NSPS Subpart OOOOb into the Reservation Air Code (RAC) in late 2024 or early 2025.

The development of a TIP for adopting the Emissions Guidelines in NSPS Subpart OOOOc continues the Tribe's mission to improve air quality on the Reservation while also maintaining national air quality standards outlined in NAAQS. Although the development of a TIP is not required, the Tribe plans to develop and implement a TIP to increase tribal sovereignty and advance the Tribe and Commission's goals of having authority of all core CAA programs on the Reservation.

Table 2 is a summary of the Tribe's priority measure, voluntary implementation of CAA programs and standards. This includes TMNSR and FIP Implementation, NSPS Adoption, and TIP development.

Table 2. TMNSR and FIP Implementation, NSPS Adoption, and TIP Development Summary

TMNSR and FIP Implementation, NSPS Adoption, and TIP Development Summary	
Implementing agency	Southern Ute Indian Tribe Air Quality Division
Geographic location	Oil and gas sources within the boundary of the Reservation
Applicable sector	Oil and gas (industrial)
Funding sources	CPRG Implementation Grant
Metrics tracking	The Tribe will evaluate emissions reduction from the proposed measure in their tri-annual emissions inventories. The next emissions inventory is for CY 2023 and will be complete in 2025.
Cost estimate	To be determined
Annual estimated GHG and criteria air pollutant emission reductions	654.3 metric tons of GHG, 1.8 metric tons of VOC
Implementation authority milestones	Delegation of TMNSR and FIP. Adoption of NSPS OOOOb under the Tribe's automatic NSPS delegation authority. Development of a TIP to adopt the Emissions Guidelines of NSPS OOOOc.
Implementation schedule	The Tribe anticipates the delegation of the TMNSR and FIP by the end of CY 2024. The new NSPS OOOOb & OOOOc rules were published in the Federal Register on March 8, 2024, and the AQD anticipates adoption of NSPS OOOOb in late 2024 or early 2025. AQD plans to submit a draft TIP to adopt the Emissions Guidelines of NSPS OOOOc to EPA for approval in 2026.

4.2.1 Other GHG Emission Reduction Measures Administered by AQD

Greenhouse gas emissions and other pollution reduction measures have been an ongoing goal of the Tribe. The Tribe has received voluntary delegation of multiple CAA programs and air quality regulations from the EPA, which can be viewed in detail in the RAC (Appendix C). A detailed summary of current and future emission reduction measures is included in Table 3 below.

Table 3. Summary of AQD GHG Reduction Measures

GHG Reduction Measure	Summary
Air Monitoring	The Tribe operates three State and Local Air Monitoring Stations to monitor air quality on the Reservation. Ambient air monitoring data collected from these stations are reported to the EPA Air Quality System for NAAQS determinations and EPA's AirNow website for generating real-time health risk forecasting. To enable Tribal members and the public with access to this information, the Tribe maintains a website with real-time ambient pollutant concentrations and the corresponding EPA AirNow index values. The AirNow index values are a color-based rating system to help people understand when air quality can be harmful to their health.
Title V Operating Permit Program	On March 2, 2012, the EPA issued a final rule approving the Tribe's Title V Program application. This granted the Tribe full authority to implement and administer its 40 CFR Part 70 Operating Permit Program for Title V sources within the exterior boundaries of the Reservation. The Tribe currently has Title V permits issued to 35 sources, which comprises approximately 14% of all Title V sources in the State of Colorado within less than 1% of the State land base. The Tribe conducts bi-annual compliance inspections based on an EPA-approved CMS and initiates civil enforcement actions for non-compliance with permit terms and conditions. The Southern Ute Indian Tribe is currently the only Tribe with a fully delegated Part 70 operating permit program. Title V operating permits are legally enforceable documents issued to major stationary sources after a source has begun operation. Operating permits include all federal, state or tribal air pollution regulatory requirements that apply to the source. The program does not allow for the addition of new emissions control requirements, but rather clarifies the air pollution control obligations of major sources by compiling in one document all of a source's compliance requirements. The intent is that by including all applicable requirements in one permit, it will be easier for the source owner, the regulatory agency, and the public to determine if the source is in compliance. The permits may contain, at the discretion of the permitting agency, additional monitoring, recordkeeping, and reporting requirements designed to ensure that the source maintains compliance with existing applicable requirements of the permit. Owners of sources with operating permits must certify that the source is in compliance each year and the permits must be renewed every five years. Each issued operating permit is subject to public comment and offers the public an opportunity for a hearing.

GHG Reduction Measure	Summary
NSPS & NESHAP	On September 6, 2013, the EPA issued a final rule delegating authority to the Tribe to implement and enforce CAA Section 111 (NSPS) and CAA Section 112 (NESHAP). NSPS and NESHAP set the minimum standards for certain new, modified, and existing sources of air pollution. The EPA delegation provided the Tribe with full upfront approval to voluntarily implement and enforce any NESHAP that the Commission chooses to include by reference at Article II, Part 3 of the RAC. EPA also delegated voluntary authority for the Tribe to implement and enforce certain NSPS that were incorporated by reference into Article II, Part 2 of the RAC by the Commission. Although it's unnecessary for the Tribe to have delegation of the NSPS and NESHAP standards for the purposes of implementing and enforcing these standards as applicable requirements of Title V permits, the delegation of these rules provides the Tribe with the authority to enforce the standards independently of a Title V permit. The Tribe and Commission plan to consider the incorporation of any new NSPS and NESHAP that apply to Reservation sources into the RAC.
Emission Inventory Development	The Tribe plans to continue development of emissions inventories for the Reservation to aid in future air quality planning and program development for maintaining compliance with the NAAQS. Comprehensive emission inventories will be completed no less than every three years and emission inventories of Title V sources will be completed annually. At the request of EPA, the Tribe is developing a QAPP for emission inventories which outlines the procedures followed by the Tribe during development of emission inventories. The procedures outlined in the QAPP will describe how the Tribe's emission inventory development adheres to the guidelines set forth in EPA's Emission Inventory Improvement Program.

In addition to the above-described GHG reduction measures, the Commission's Long Term Plan describes several additional measures which the Tribe and Commission may consider implementing in the future. These include: (1) a pollutant-specific voluntary program such as the EPA's Ozone Advance or Methane Challenge or a TIP (programs to reduce VOC and methane emissions), (2) consideration of adopting certain State of Colorado air quality initiatives for the oil and gas industry or other industries, (3) a Prevention of Significant Deterioration program, (4) the designation of the Reservation as its own air quality control region, and/or (5) any program or rule deemed beneficial for the health of the Reservation's residents or its environment (such as a visible emissions rule or GHG initiatives). These and other programs may be included in the CCAP.

4.2.2 Other GHG Emission Reduction Measures Occurring on the Reservation

Several Tribal-owned business entities and departments, including Red Willow, Red Cedar, and DOE, and other private business entities on the Reservation, are engaged in other GHG emissions quantification efforts and potential GHG emission reduction projects and the Tribe will continue to engage these entities. The Tribe plans to include the power generation and potential GHG emission reductions from these projects in the GHG emissions inventory and CCAP evaluation and to integrate the data generated from Tribal business entity emission quantification efforts into the CCAP. Table 4, below, is a summary of some of these GHG emissions reductions projects.

Table 4. Summary of Other GHG Emission Reduction Projects.

Enterprise	Project	Estimated Cost	Project Start	Project Completion
Red Willow Production Company	Admin Vehicle Electric Vehicle (EV) Pilot - Pilot program to evaluate use of EVs for non-critical vehicle fleet (admin, engineering, wells team, etc).	TBD	TBD	TBD
Red Willow Production Company	Solar installations on office building roofs - Install solar power systems on Red Willow building roof. Look at other options in field to offset emissions on larger industrial buildings (new materials warehouse).	TBD	TBD	TBD
Red Willow Production Company	Routine aerial methane detection surveys - Drone or Fixed wing. Working to establish methodology and frequency. Detect and fix leaks before they emit for extended duration and monitor progress on methane emission reduction programs	$400,000/ year	ASAP	ongoing
Red Willow Production Company	Pneumatic Retrofit Program - Eliminate up to 80% of methane emissions associated with gas driven pneumatic devices on natural gas well pads and associated facilities on Red Willow-operated assets on the Reservation.	$3.5-5MM	ASAP	5-7 years
Red Willow Production Company	Continuous Monitoring Installations - Install new devices to monitor methane (and other) emissions continuously. Allow for notifications to operators when leaks are detected and measure actual emissions for reporting to regulatory agencies.	$100,000/ year	TBD	TBD
Red Willow Production Company / Red Cedar Gathering Company / DOE	Wellsite Electrification Program - Outside engineering firm to conduct grid study to compare existing power infrastructure to gas production and transportation facilities to determine approach towards grid improvements. Engineering firm will develop priority areas based on proximity, cost, reduced emissions, and wellsite/facility profitability (lifespan of operation). Reduction in CH_4, CO_2, N_2O, $PM_{2.5}$, PM_{10} and VOC emissions.	$10MM+	Grid study planned for 2024, installation 2025	10 years
Red Willow	Emissions Tracking Database - Specialized software for tracking emissions and results of reduction programs.	$100,000/ year	ASAP	ongoing

Enterprise	Project	Estimated Cost	Project Start	Project Completion
DOE	Enhanced Outcrop Methane Capture Project - Project includes installation of two shallow horizontal methane capture pilot wells with the goal of reducing naturally occurring methane seepage from the Fruitland Coal outcrop by intercepting the methane in the subsurface before it is emitted. The project also includes pilot testing of Bridger Photonics, Trellisense, and other advanced methane detection technologies in the San Juan Basin and statistical analysis of historic methane seepage data to guide future seep mitigation efforts and reduce methane seepage to the atmosphere.	$5MM	ongoing	12/1/2025
DOE	Grid Resiliency Grant - The DOE was awarded a grant to improve grid resiliency and decrease power outages on the Reservation. This grant is a partnership with La Plata Electric Association. Grid resiliency projects reduce power outages at industrial facilities and require fewer well interventions and work overs which require venting methane to the atmosphere thereby reducing methane emission. The Tribe expects to receive an additional $750,000 in formula grant funding over the next three fiscal years as part of the program and is looking into additional electrification of oilfield equipment to reduce methane emissions.	$340,000	ongoing	1/1/2027
DOE	Orphaned Well Program Grant - The DOE was awarded a grant through the Department of the Interior to investigate wells plugged and abandoned on the Reservation prior to the year 2000. The work is aimed at a desktop and field review of these sites and the goal is to ensure tribal minerals are protected and are not leaking to the atmosphere. This is the first phase of the work and subsequent phases will focus on plugging any wells which are found to be leaking methane to the atmosphere.	$500,000	2/1/2024	2/1/2027

Enterprise	Project	Estimated Cost	Project Start	Project Completion
DOE	Orphaned Well Plugging - The Tribe is actively managing plugging and abandonment of two orphaned wells on the Reservation. Plugging of the wells may reduce fugitive methane emissions.	~$100,000 /year	ongoing	TBD
Growth Fund	Arkansas Loop/Simpson Treating Plant CO_2 Sequestration Project - Plan to capture 250,000 metric tons of CO_2 from the existing Arkansas Loop/Simpson natural gas treating plant to be routed to a pipeline for subsequent geologic sequestration via subsurface injection.	TBD	TBD	TBD
Growth Fund	Coyote Clean Power Project - The capture of CO_2 from a 250 MW natural gas-fired powerplant that is currently under construction. The CO_2 will be routed through a pipeline for subsequent geologic sequestration via subsurface injection.	TBD	TBD	TBD
Growth Fund	Lidar Flyover of the Reservation - Undertaken by the Growth Fund under the IRA MERP grant and private funding to quantify methane emissions on the Reservation.	TBD	TBD	TBD
Primergy Energy	Solar Energy Project - The planning phase of a project for a 1,920-acre, 155 MW solar energy project on the Reservation.	TBD	TBD	TBD

Notes: ASAP – as soon as possible; MM – millions; MW – megawatt; Lidar – Light Detection and Ranging; MERP – Methane Emissions Reduction Program; TBD – to be determined

4.3 GHG Emissions Projections and Reduction Targets

For the purposes of the PCAP, the Tribe has established GHG emissions projections and reductions from leaking components at minor oil and gas sources, on a per-site basis, and forecasted the anticipated reduction through five years of inspections under the Tribe's proposed five-year EPA approved minor source CMS. The Tribe has also provided emissions projections and reductions through 2050.

The Tribe has developed an emissions reductions quantification method utilizing (1) leaking component and fugitive emissions data from the Tribe's 2020 EI, (2) minor source data for Reservation sources, and (3) a report developed by CARB titled "*CARB's Oil and Gas Methane Regulation 2018 Annual LDAR Summary*". The CARB report summarized emission reductions from leaking component identification and subsequent corrections.

Emissions Projections:

To establish emission projections, the Tribe first determined the GHG emissions contributions

from leaking components, fugitive emissions and pneumatic devices at true minor oil and gas sources on the Reservation for the baseline year of CY 2020, using data from the Tribe's 2020 EI. The Tribe used these data to project GHG emissions forward from base year 2020 by determining a per source GHG emissions estimate and an estimated minor oil and gas source growth rate.

Based on the CY 2020 EI, the Tribe has estimated that one true minor source has a PTE of 520.67 CO_2e metric tons per year. The Tribe established an estimated true minor source growth rate by downloading the current FIP registration data from the EPA Region 8 and determining a per year average for new true minor sources based on source registrations from 2016 through the beginning of 2024. By averaging the number of sources registered between 2016 and 2024, the Tribe determined an estimated true minor source growth rate of 4.3 new sources per year. To project emissions forward from the currently known number of true minor sources on the Reservation for 2023 (254 sources), the Tribe applied the 4.3 sources per years growth rate and multiplied it by the per source estimated GHG emissions of 520.6 metric tons of CO_2e per year.

Using this methodology, the Tribe estimated that, without voluntary implementation of CAA programs and standards, GHG emissions from leaking components, fugitive emissions and pneumatic devices will increase by 654.6 metric tons of CO_2e per year. Projecting this per year emissions increase forward for a five-year period would yield an increase of 3,271.5 metric tons of CO_2e. Total estimated emissions from leaking components, fugitive emissions and pneumatic devices for year 2025 are 136,590.4 metric tons of CO_2e and 147,871.7 metric tons for year 2030.

Reduction Targets:

To establish a GHG emissions reduction target, the Tribe applied the 29% GHG emissions reduction observed in the 2018 CARB report to each projected year, from 2025 through 2050. The CARB report determined that leak detection and repair inspections resulted in a 29% reduction in fugitive gas emissions from leaking components.

During the first five years, through the Tribe's voluntary administration and implementation of CAA programs and standards and corresponding compliance inspections at all regulated sources, the Tribe expects to see approximately 39,611.2 metric tons of GHG emissions.

As of April 1, 2024, there were 258 true minor sources registered under the FIP and six synthetic minor sources permitted through the TMNSR program on the Reservation. For the purposes of emissions projection and estimated reductions, the Tribe has assumed synthetic minor sources to have the same per site emissions and emissions reduction potential as true minor sources. In actuality, synthetic minor sources are larger sources and are likely to have higher emissions rates and higher corresponding emission reductions.

Table 5 is a summary of the number of estimated sources (true minor and synthetic minor), emissions projections that would occur without voluntary implementation of CAA programs and standards, and emissions reduction targets based on the assumptions and calculations presented above.

Table 5. Emissions Projections and Reductions Targets.

Year	Number of Sources	GHG Emissions Projection by Year (tpy CO_2e)	GHG Emission Reduction Target (tpy CO_2e)
2020	238	123,920.7	-
2021	243	126,524.0	-
2022	250	130,168.8	-
2023	254	132,251.5	-
2024	258*	134,334.2	-
2025	262.3	136,590.4	39,611.2
2026	266.7	138,846.7	40,265.5
2027	271.0	141,102.9	40,919.8
2028	275.3	143,359.2	41,574.2
2029	279.7	145,615.4	42,228.5
2030	284.0	147,871.7	42,882.8
2031	288.3	150,128.0	43,537.1
2032	292.7	152,384.2	44,191.4
2033	297.0	154,640.5	44,845.7
2034	301.3	156,896.7	45,500.1
2035	305.7	159,153.0	46,154.4
2036	310.0	161,409.3	46,808.7
2037	314.3	163,665.5	47,463.0
2038	318.7	165,921.8	48,117.3
2039	323.0	168,178.0	48,771.6
2040	327.3	170,434.3	49,425.9
2041	331.7	172,690.5	50,080.3
2042	336.0	174,946.8	50,734.6
2043	340.3	177,203.1	51,388.9
2045	344.7	179,459.3	52,043.2
2046	349.0	181,715.6	52,697.5
2047	353.3	183,971.8	53,351.8
2048	357.7	186,228.1	54,006.1
2049	362.0	188,484.4	54,660.5
2050	366.3	190,740.6	55,314.8
Total Emissions Reductions 2025-2050			**1,186,574.9**

Notes: number of sources are based on EPA permitting data from 2016-2024 and projected for 2024-2050; tpy – tons per year; "-" – indicates no data; * - 2024 sources based on sources as of April 1, 2024.

Refined projections and reductions targets may be included in the CCAP.

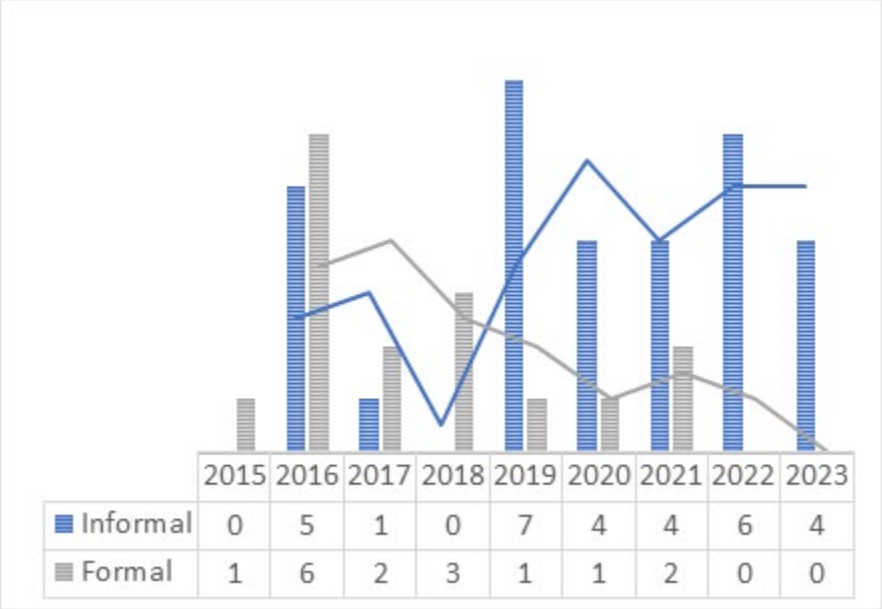
4.4 Benefits Analysis

The AQD, Commission, State of Colorado, and Tribe believe that the Tribe's administration of the TMNSR program and FIP, would result in increased compliance with CAA permit programs

and standards on the Reservation through increased source oversight by the of the Tribe and application of the Tribe's established CAA compliance and enforcement sections. To date, true minor sources on the Reservation have never been inspected by the EPA and synthetic minor sources are only inspected by the EPA every five years. Additionally, based on emissions information submitted to the Tribe as part of the 2020 EI development, it's likely that a number of sources on the Reservation are operating without applicable CAA permits and may be out of compliance with other CAA standards. Because EPA does not currently perform on-site inspections of the known minor sources on the Reservation or investigate potentially applicable sources on the Reservation, the Tribe intends to perform the work of the EPA in administering these responsibilities, voluntarily. The Tribe plans to inspect the known true minor sources on a five-year basis and synthetic minor sources on a two-year basis, through an EPA-approved CMS. The Tribe will work to bring all sources into compliance using the Tribe's authority to implement CAA programs.

The Tribe has a proven record of improving compliance with the CAA on the Reservation, through its voluntary implementation of the Title V operating permit program. When the Tribe began performing Title V source inspections in 2015 under its voluntary 2012 delegation of the Title V operating permit program, non-compliance with CAA rules was prevalent. As displayed in Figure 3, below, compliance has significantly improved since that time, as can be determined through examining the downward trend of formal enforcement actions being initiated by the Tribe from 2015 through 2023. In general, formal enforcement actions include more significant instances of CAA non-compliance, including types on non-compliance that are more likely to have caused, or have the potential to cause, environmental harm. Informal enforcement actions are generally for smaller occurrences of CAA non-compliance that are unlikely to have caused environmental harm, such as minor recordkeeping or reporting deviations.

Figure 3. CAA Enforcement at Title V Sources by Calendar Year



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Informal	0	5	1	0	7	4	4	6	4
Formal	1	6	2	3	1	1	2	0	0

Many of the formal enforcement actions initiated by the Tribe involved similar instances of non-compliance at multiple sources owned by the same owner/operator and resulted in significant penalties under the Tribe's Enforcement Procedures and Penalty Policy. Based on the results of the Tribe's Title V inspections, it's expected that increased compliance oversight will have a similar effect on true minor sources and synthetic minor sources on the Reservation and result in greater CAA compliance and a reduction in GHG emissions.

It is expected that the Tribe's GHG reduction plan would have a corresponding reduction of co-pollutants entrained in the natural gas stream. Co-pollutants would include VOCs, CAPs, and Haps. The reduction of VOC, an ozone precursor, could also have the co-benefit of reducing ground level ozone formation. Emission reductions will be quantified consistently with the emission factors used in the 2020 EI, or corrected to more accurate emission factors, if available.

Table 6 shows the 2020 criteria pollutants and HAP emissions from true minor oil and gas sources as calculated in the 2020 EI.

Table 6: 2020 Criteria Pollutant and HAP Emissions from True Minor Sources (tons)

Pollutant	**NOx**	**CO**	**VOC**	**PM**	**SO2**	**Total HAP**	**GHG (CO_2e)**
Emissions	4,575.2	3,248.1	834.5	42.8	16.1	291.0	1,568,843.6

The Tribe's proposed GHG reduction measure will reduce CAPs and other HAPs in addition to GHG emissions. An estimation of these reductions was developed for VOCs and projected estimates and the correlating reduction targets are included in Table 7 below.

Table 7. VOC Estimated Projections and Reductions

Year	**VOC Emissions Projection by Year (tpy)**	**VOC Emission Reduction Target (tpy)**
2020	330.8	-
2021	337.8	-
2022	347.5	-
2023	353.1	-
2024	358.6	-
2025	364.6	105.7
2026	370.7	107.5
2027	376.7	109.2
2028	382.7	111.0
2029	388.7	112.7
2030	394.8	114.5
2031	400.8	116.2
2032	406.8	118.0
2033	412.8	119.7
2034	418.9	121.5
2035	424.9	123.2

Year	VOC Emissions Projection by Year (tpy)	VOC Emission Reduction Target (tpy)
2036	430.9	125.0
2037	436.9	126.7
2038	442.9	128.5
2039	449.0	130.2
2040	455.0	131.9
2041	461.0	133.7
2042	467.0	135.4
2043	473.1	137.2
2045	479.1	138.9
2046	485.1	140.7
2047	491.1	142.4
2048	497.2	144.2
2049	503.2	145.9
2050	509.2	147.7
Total Emissions Reductions 2025-2030	**2,278.2**	**660.6**
Total Emissions Reductions 2025-2050	**10,923.1**	**3,167.7**

Notes: tpy – tons per year

In addition to the Tribe's primary PCAP goal of reducing GHG emissions relating to the repair of leaking fugitive emission sources, the AQD also anticipates that increased compliance oversight of minor sources by the Tribe will result in secondary co-pollutant emission reductions of CAPs from internal combustion engines, glycol dehydration units, and other oil and gas production equipment. Co-pollutants would include NO_x, CO, VOC, and HAPs. These emission reductions would be realized through increased compliance with NSPS and MACT rules relating to these types of oil and gas emission units.

4.5 Review of Authority to Implement

All lands located within the exterior boundaries of the Reservation are under the jurisdiction of the Reservation Air Program established by the Intergovernmental Agreement between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation (Pub. L. No. 108-336, 118 Stat. 1354). The Intergovernmental Agreement is managed by the Commission, which serves as the policy-making and administrative review authority for the Reservation Air Program, and the AQD has been delegated the administration of the Reservation Air Program.

In 2012, the EPA issued a final rule approving the Tribe's Title V Program application, granting the Tribe full authority to implement and administer its 40 CFR Part 70 Operating Permit Program for Title V sources within the exterior boundaries of the Reservation. Additionally, on September 6, 2013, EPA issued a final rule delegating authority to the Tribe to implement and enforce CAA §111 (NSPS) and CAA §112 (NESHAP and MACT).

The Tribe and EPA are currently finalizing a delegation agreement for administration of the federal TMNSR Program and the FIP. The Tribe anticipates receiving the full authority to implement the programs in 2024. Once delegation is received, the Tribe will have authority to issue permits and conduct compliance inspections under the TMNSR program and FIP. Enforcement authority under these programs is not delegable to Tribes and will remain with EPA; however, the Tribe has independent authority to implement and enforce the NSPS, NESHAP and MACT standards, which are incorporated by reference by the FIP, and which in many instances are the primary emissions standards and limits that apply at minor oil and gas sources. Therefore, under these EPA delegations, the Tribe will have substantial authority to implement the voluntary CAA programs and standards being proposed by this PCAP.

Other GHG emissions reduction measures may be outside the authority of the Commission and the Tribe to implement or would require Tribal Council approval. The Tribe may offer support to projects outside their jurisdiction.

4.6 Identification of Other Funding Mechanisms

The Tribe has applied for and received partial funding for activities related to development and administration of the TMNSR program and FIP under Fiscal Year (FY) 23 and FY24 CAA §105 grants, a small FY24 CAA IRA grant, an FY22 Multi-purpose Grant, an FY22 General Assistance Program (GAP) grant, and FY21 and FY22 CAA §103 grants. In some of these funding examples, no funding or only partial funding was provided to the Tribe.

The Tribe's delegation request application was conditioned upon the Tribe receiving assurance from EPA Region 8 of a continued funding source for year-to-year administration of the programs by the Tribe. This request was to provide the Tribe with assurance that the programs could be funded into the future and confidence that the Tribe's efforts to build the resource and staffing needs to successfully administer the program are preserved. The EPA has been unable to provide the Tribe with funding assurance, and therefore, the Tribe has sought funding from multiple grant opportunities to fund the development and future implementation of these programs. In FY23, it was recommended by EPA Region 8 staff that the Tribe pursue funding under the CPRG as a potential funding source to administer the TMNSR and FIP. In addition to the CPRG implementation grant, the Tribe plans to continue concurrently applying for funding each fiscal year under CAA §105 and GAP to ensure sufficient funding can be secured to administer the programs.

4.7 Workforce Planning Analysis

For the purposes of the Phase II implementation grant, the Tribe anticipates the need for staff hours from six full-time AQD positions, including, (1) the AQDH, (2) the Air Quality Technical Manager (AQTM), (3) two AQ Planners, (4) the Senior Air Quality Compliance Specialist (SAQCS), and (5) a Grants Coordinator (GC). The AQDH and AQTM would be responsible for directing the broad scale planning, resource development, and meeting planning for the CCAP. The AQ Planners would be responsible for the detailed plan development, GHG emission inventory development, and meeting agenda development. The SAQCS would be responsible for CCAP planning and resource development, specific to the AQD's inspection and emission reduction activities at TMNSR and FIP oil and gas sources. In addition, the SAQCS was a position

identified by the Tribe as necessary to fulfill the resource needs that would be assumed by the Tribe under an administrative delegation of the TMNSR program and FIP for the purpose of inspecting and documenting compliance and non-compliance at the six synthetic minor sources and over 250 true minor sources. The GC would be responsible for on-going grant reporting, development, and analysis for the CCAP.

The Tribe is dedicated to being a premier employer in the southwestern region of Colorado. The Tribe offers competitive wages and a significant employee benefits package that includes paid holidays, health insurance, annual and sick leave accrual, dental, vision, life insurance, and retirement plans for full-time employees. This also includes training opportunities, technology, workwear, and certifications, as needed, for individuals to perform job duties.

The EPA considers the Reservation and Tribal members an environmental justice population. Creation of high-quality jobs in environmental justice populations is a high priority of the EPA and the Tribe.

The Tribe follows the requirements of the Davis-Bacon and Related Acts for hiring contractors and subcontractors for performing on federally funded and assisted contracts that exceed $2,000 for public works projects.

The Tribe understands that the need for sustainability, innovation, and efficient strategies to reduce GHG is an on-going effort that will result in new training opportunities, expansion of current environmental departments, and on-going education efforts for current and future employees. The Tribe will continue to seek new training and work closely with both state and federal entities to ensure employees are receiving the latest available training and educational opportunities to enhance workforce development.

5 Next Steps

The results of the survey outlined in Section 3.3 will inform sections of the CCAP and future GHG reduction projects on the Reservation.

Oil and gas production is the single-largest emitter of GHG on the Reservation and thus remains the Tribe's priority sector. Other sectors that will be included in the analysis in the CCAP include mobile combustion, electricity consumption, urban forestry, agriculture, waste generation, wastewater treatment, and water sectors. The Tribe will determine what source sectors are viable for potential GHG emission reductions, including sectors where the Tribe has authority to implement the measures, and those where the Tribe does not. Certain CCAP milestones and target completion dates will be based off the scheduled completion and implementation dates of projects being conducted by entities outside of the Tribe, including the oil and gas industry and other private industry, such as solar installation companies.

Appendix A: 2020 EI

Final Report for 2020 Southern Ute Indian Tribe Comprehensive Emissions Inventory for Criteria Pollutants, Hazardous Air Pollutants, and Greenhouse Gases

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January 2023

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List of Acronyms

AP-42	EPA Compilation of Air Pollutant Emission Factors
API	American Petroleum Institute
AQP	Air Quality Program
BIA	United States Bureau of Indian Affairs
BSFC	Brake Specific Fuel Consumption
BTEX	Benzene, Toluene Ethyl-Benzene, Xylene
bbl	Barrel (42 U.S. Gallons)
CAA	Clean Air Act
CARMMS	Colorado Air Resource Management Modeling Study
CDPHE	Colorado Department of Health and Environment
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO2*e*	Carbon Dioxide Equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CY	Calendar Year
CFR	Code of Federal Regulations
DRMS	Colorado Division of Reclamation Mining and Safety
EI	Emissions Inventory
EIA	Environmental Impact Assessment
EPA	United States Environmental Protection Agency
FAA	Federal Aviation Administration
GHG	Greenhouse gas
GSJB	Greater San Juan Basin
HAP	Hazardous Air Pollutants
hp	Horse Power
H_2S	Hydrogen Sulfide
ICR	Information Collection Request
ITEP	Institute for Tribal Environmental Professionals
Kdf	Cretaceous Fruitland Formation
Kpcl	Cretaceous Picture Cliffs Sandstone
LFG	Landfill Gas

LP	Liquid Petroleum
LTO	Landing and Take-off Cycles
MMscf	Million Standard Cubic Feet
MSW	Municipal Solid Waste
NEI	National Emissions Inventory
NMHC	Non-methane Hydrocarbons
NMOC	Non-methane Organic Compounds
NO_x	Oxides of Nitrogen
NPS	National Park Service
O_3	Ozone
Pb	Lead
PM_{10}	Particulate Matter 10 microns and smaller
$PM_{2.5}$	Particulate Matter 2.5 microns and smaller
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
QA	Quality Assurance
RICE	Reciprocating internal combustion engine
scf	Standard Cubic Feet
SO_2	Sulfur Dioxide
SUIT	Southern Ute Indian Tribe
TEG	Tri-ethylene Glycol
TEISS	Tribal Emissions Inventory Software Solutions
THC	Total Hydrocarbons
TMNSR	Tribal Minor New Source Review Program
TOC	Total Organic Compounds
tpy	Tons per Year
USFS	United States Forest Service
VOC	Volatile Organic Compounds
WRAP	Western Regional Air Partnership
4SLB	Four stroke lean burn
4SRB	Four stroke rich burn
2SLB	Two stroke lean burn

I. Executive Summary

The Southern Ute Indian Tribe (Tribe) Air Quality Program (AQP) has prepared an emissions inventory of quantifiable point and non-point sources on the Southern Ute Indian Reservation (Reservation) for calendar year 2020 (CY2020). The emissions inventory was prepared according to the Environmental Protection Agency Class II emission inventory guidelines of using measured data when available or data and emissions factors from reputable sources when measured data were not available.

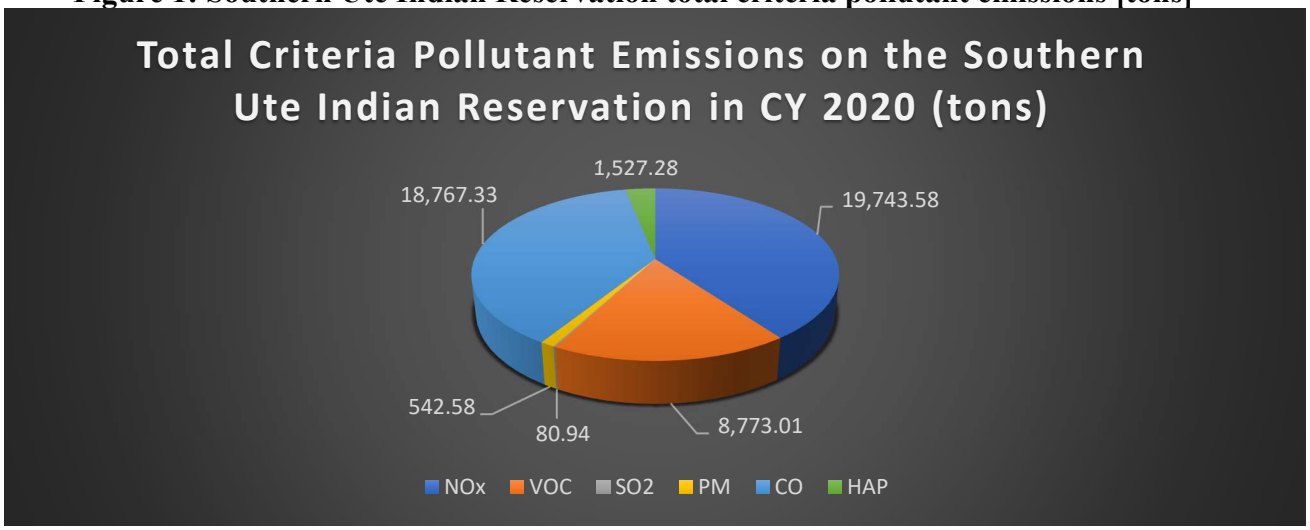
Oil and natural gas production is the predominant industry on the Reservation and emissions data for these sources were collected directly from source operators through annual emission inventories, registrations from sources under the Tribal Minor New Source Review (TMNSR) program (true minor sources), and a Clean Air Act (CAA) Section 114 information collection request issued by the Tribe in June 2021. Data for other sources were collected from various reputable state, local, and federal data sources.

This report also covers emissions from landfills, nonpoint sources, mobile sources, wildfires, biogenic sources, and the Fruitland outcrop. Nonpoint sources include agricultural burning, residential heating, gravel pits. gas stations, and airports.

Reservation emission totals for CY 2020 were 19,743.58 tons of oxides of Nitrogen (NOx), 8,773.01 tons of Volatile Organic Compounds (VOC), 80.94 tons of Sulfur Dioxide (SO_2), 396.57 tons of Particulate Matter 10 micrometers or less in diameter (PM_{10}), 146.02 tons of Particulate Matter 2.5 micrometers or less in diameter ($PM_{2.5}$), 18,767.33 tons of Carbon Monoxide (CO), 1,527.28 tons of total Hazardous Air Pollutants (HAP), and 11,342,510.62 metric tonnes of Greenhouse Gas (GHG) emissions measured in Carbon Dioxide Equivalent (CO2*e*).

Total criteria pollutant (NOx, VOC, SO_2, PM_{10}, $PM_{2.5}$, CO) and HAP emissions on the Reservation for 2020 are presented below in Figure 1.

Figure 1: Southern Ute Indian Reservation total criteria pollutant emissions [tons]



II. Overview

1. Purpose of Inventory

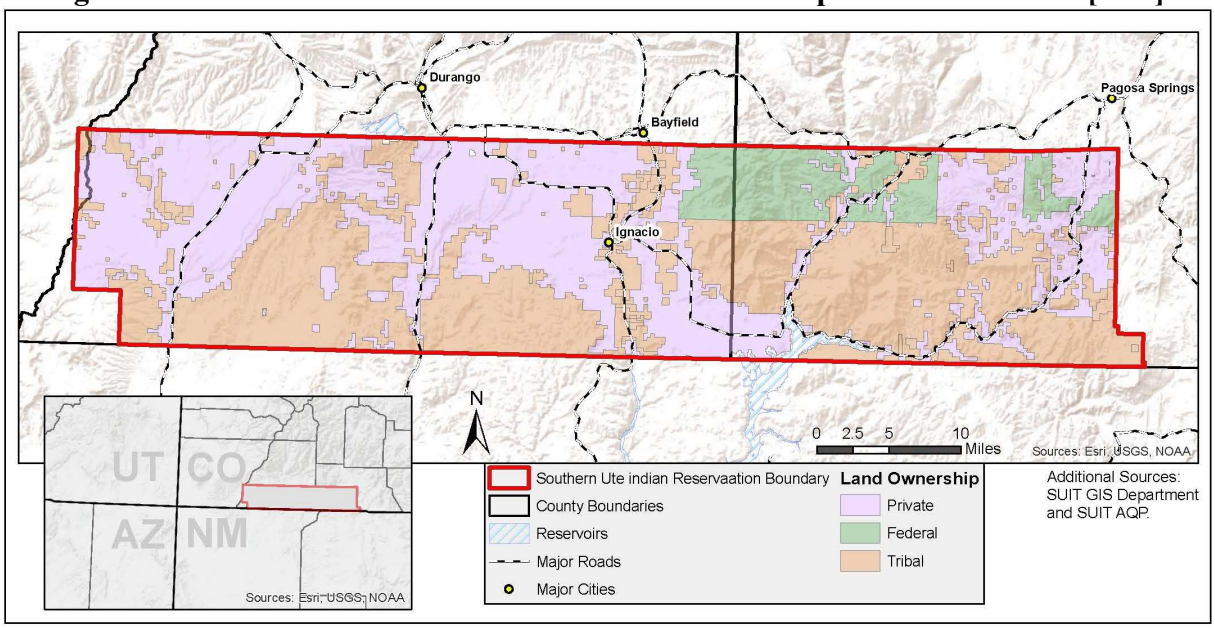
The purpose of this Emissions Inventory (EI) was to establish baseline emissions estimates for the 2020 calendar year for all quantifiable air emission sources located within the exterior boundaries of Reservation. The emissions data for the Reservation presented in this EI has been organized by source category and pollutant. The EI will be used for future air quality planning purposes, such as development of air quality regulations targeted at ozone precursors for maintaining attainment with the National Ambient Air Quality Standards, emissions modeling, and Title V permitting fee analysis.

The primary air pollutants included in this EI are NOx, CO, PM_{10}, $PM_{2.5}$, VOC, HAP, and GHG.

2. Geographic Location of Southern Ute Indian Reservation

The Reservation is located in southwestern Colorado. The Reservation land area covers 1,066 square miles in three counties (La Plata, Archuleta, and Montezuma) and borders New Mexico to the south (Figure 2). The total area covered by this inventory is approximately 682,590 acres, which encompasses all land within the external boundaries of the Reservation. The Southern Ute Indian Tribe (Tribe) and/or its members own approximately 320,000 acres, while the remaining land mass is comprised of non-Indian and government land in a checkerboard fashion. The primary land use is agricultural, and the predominant industry is oil and natural gas production.

Figure 2: Southern Ute Indian Reservation total criteria pollutant emissions [tons]



3. Climate

The Reservation remains generally semi-arid throughout the year. Located north of northern New Mexico desert land and south of the Colorado alpines, the average temperature range during the winter months average temperatures are between 20 and 40 degrees Fahrenheit. Freezing temperatures are common throughout the winter and during the 2020 calendar year the coldest month was February with a low of 3.4 degrees Fahrenheit and a monthly average of 32.4 degrees Fahrenheit. During the summer months the average high temperatures were in the high eighties and nineties. The warmest month of 2020 was July with a high of 99.6 degrees Fahrenheit, and a monthly average of 73.6 degrees Fahrenheit. Rain was the dominant form of precipitation on the Reservation and total precipitation for calendar year 2020 was 4.0 inches. The driest month was June with 0.3 inches of precipitation and the wettest month was August with 2.2 inches of precipitation.[1]

4. Geology

The Reservation is situated in the northern portion of the San Juan Basin, a geologic structural basin underlying southwestern Colorado and northwestern New Mexico. The basin is composed of Cambrian to Holocene aged sedimentary rocks and contains one of the

[1] Southern Ute Indian Tribe: Ambient Monitoring. (2020). *2020 AQS Ute 3 Humidity and Temperature Hourly Data.* Retrieved from: http://www.southernute-nsn.gov/environmental-programs/air-quality/ambient-monitoring/.

largest coal-bed methane natural gas fields in the world within the Cretaceous aged Fruitland Formation.[2] The majority of the natural gas production on the Reservation is coalbed methane from the Fruitland Formation, but conventional natural gas is also produced from Cretaceous aged sandstone reservoirs of the Pictured Cliffs Formation, Mesa Verde Group, and the Dakota Sandstone. Tight gas reservoirs of the Cretaceous aged Mancos Shale have also been drilled, however, no significant exploration and production has occurred within the Reservation as of 2020.

5. Sources

The sources included in this emissions inventory were organized according to source type and size. These sources are as follows:

A. Point Sources

1) Title V permitted oil and natural gas sources
2) TMNSR minor oil and natural gas sources, including:
    a. Permitted minor TMNSR sources,
    b. Registered minor TMNSR sources,
3) Municipal solid waste landfills, and
4) Airports.

B. Non-point Sources

1) Small oil and gas sources,
2) Fruitland Formation Outcrop natural gas seeps,
3) Gasoline stations,
4) Aviation gasoline dispensing,
5) Gravel pits,
6) Residential heating, and
7) Agricultural burning.

C. Mobile Sources

1) On-road vehicles, and
2) Non-road equipment.

D. Events

[2] Fasset, J. E., & Hinds, J. S. (1971). Geology and Fuel Resources of the Fruitland Formation and Kirtland Shale of the San Juan Basin, New Mexico and Colorado. Geological Survey Professional Paper 676. United States Government Printing Office. Retrieved from https://pubs.usgs.gov/pp/0676/report.pdf.

1) Fire events (wildland fires and prescribed burns).

E. Biogenic Sources

III. Data Quality Objectives

Data objectives for this inventory are as follows:

1. Accuracy

- Data for this EI were collected according to EPA level II EI guidelines using measured data when available or data from reputable sources such as EPA, the Colorado Oil and Gas Conservation Commission (COGCC) and professional organizations when measured data were not available.
- Emission factors were developed using measured data or commonly accepted emissions factors and assumptions from EPA and professional organizations.
- All data sources, emission factors, assumptions, and emission calculation methodologies were documented.
- Emission calculation models were utilized when available (GRI-GLYCalc 4.0, Tanks 4.09d, etc.) and all inputs are provided in annual emission reports or 2020 CAA Section 114 Information Collection Request (ICR) worksheets.
- Results of the 2020 SUIT EI were compared with results from the 2017 SUIT EI.
- Quality Assurance review of emission totals, assumptions, emission factors, and calculation methodologies was conducted by a third-party contractor.

2. Uncertainty

- Reported emissions may be inaccurate.
- The number of unreported oil and gas sources is unknown and can only be estimated based on sources reported to COGCC.
- Emissions differences between CY2020 SUIT EI, CY2017 SUIT EI, and CY2015 SUIT EI may occur due to different preparation methodologies and assumptions.

3. Completeness

- Capture 100% of point source emissions reported in the annual emission fees for CY2020.
- Capture 95% of non-point oil and gas sources in the 2020 CAA 114 ICR.
- Reported information will be used to extrapolate emissions to 100% to fill data gaps.
- Capture 80% of area sources (gas stations, etc.).

4. Comparability

- EI results will be compared with results from the 2017 SUIT EI and 2015 SUIT EI.
- Emission factors and assumptions will be compared with methodologies used in similar emission calculation applications.

IV. Point Sources

As of 2020, there were a total of 2,860 oil and gas production sources operating on the Reservation. These sources consisted of 35 sources operating under Title V operating permits, 11 sources operating under TMNSR permits (synthetic minor sources), 238 true minor sources, and 2,582 non-point sources with emissions below the TMNSR program thresholds, referred to in this emissions inventory as "small oil and gas sources".

1. Title V Permitted Oil and Gas Sources

Description of Sources

Thirty-five oil and gas Title V sources operated on the Reservation during calendar year 2020. Sources include natural gas compressor stations, central delivery points, treating plants, and processing plants.

Title V sources are defined as sources with the potential to emit (PTE) 100 tons per year (tpy) of a single criteria pollutant, 25 tpy of HAP in aggregate, or ten tpy of an individual HAP. The Tribe has full delegation of a Title V operating permit program under 40 CFR Part 70 and during calendar year 2020, 35 oil and gas sources operated under Tribally-issued Title V permits.

Data Collection

Title V sources are required to report emissions annually and pay a per-ton emission fee for pollutants emitted. Emissions data for Title V sources were collected directly from the calendar year 2020 fee calculation worksheets submitted by each source to the Tribe. Actual emissions data were available for all 35 Title V oil and gas sources. GHG emissions, reported as carbon dioxide equivalent (CO2*e*) were obtained from fee calculation worksheets (if provided) and if not, the PTE listed in their most recent Title V permit renewal was used and cross checked with EPA Facility Level Information on GreenHouse Gases Tool (FLIGHT) at https://ghgdata.epa.gov/ghgp/main.do. This data collection methodology adheres to the EPA level II EI guidelines for utilizing measured data when available.

Emissions

Total criteria pollutant, HAP, and GHG emissions estimated from Title V sources for the 2020 calendar year are displayed below in Table 1.

Table 1: Title V criteria pollutant, HAP, and GHG emissions estimations [tons]*

Pollutant	NOx	VOC	SO2	PM	CO	Total HAP	GHG
Emissions	2,359.8	1,032.9	46.9	101.9	1,872.9	306.1	2,124,765.3

*CO2*e* emissions for all Title V sources are reported values obtained from annual Title V fee forms and EPA GHG data and are reported in metric tonnes

Total criteria pollutant and HAP emissions by equipment type from Title V sources for the 2020 calendar year are displayed below in Figures 3 through 5.

Figure 3: Criteria pollutant and HAP emissions at Title V sources [tons]

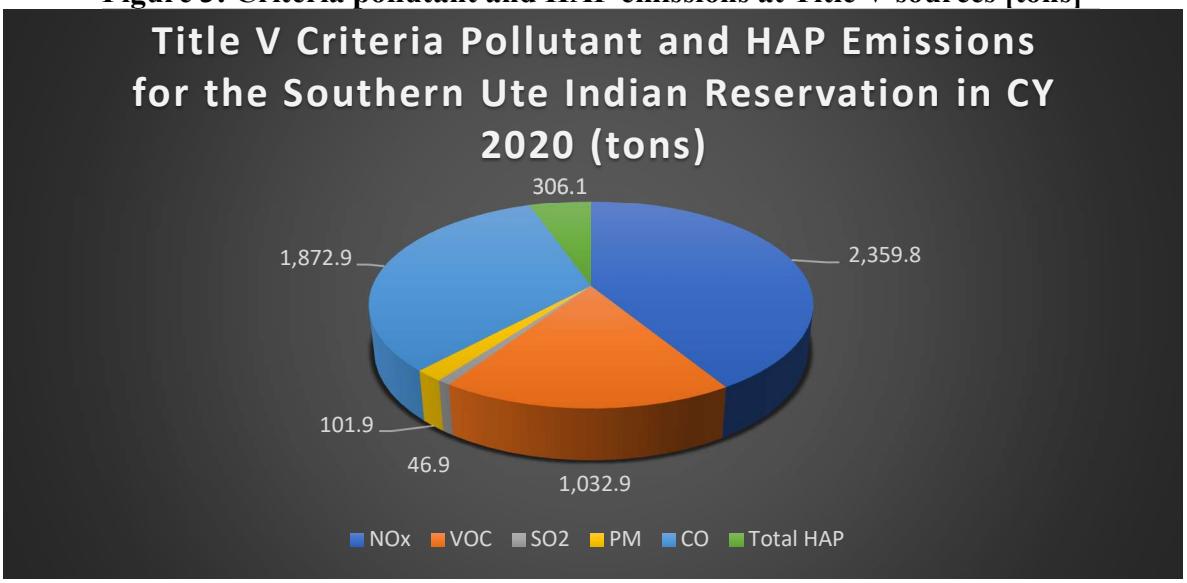
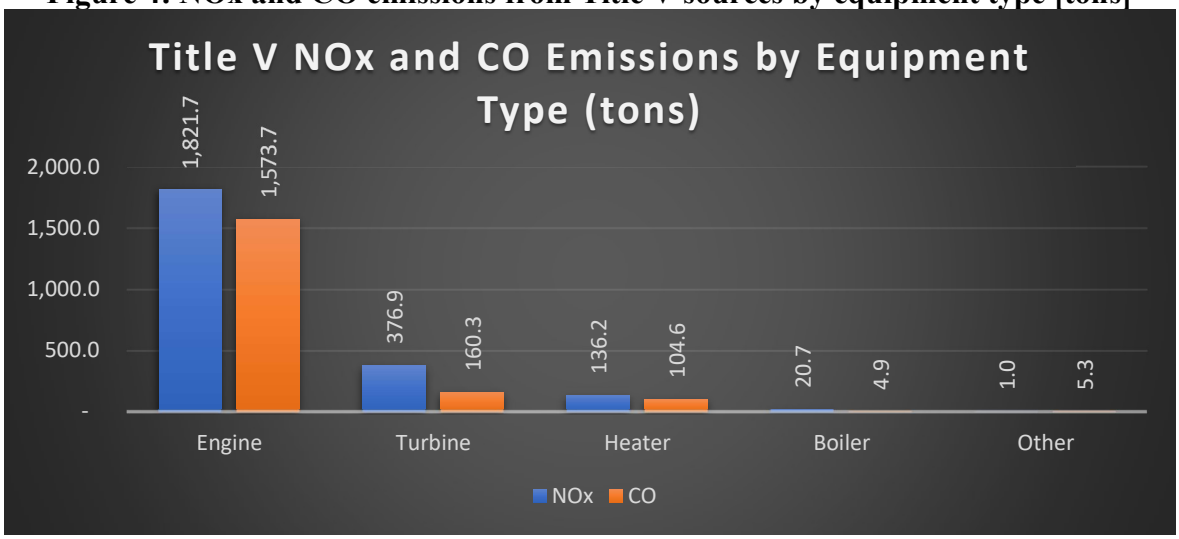
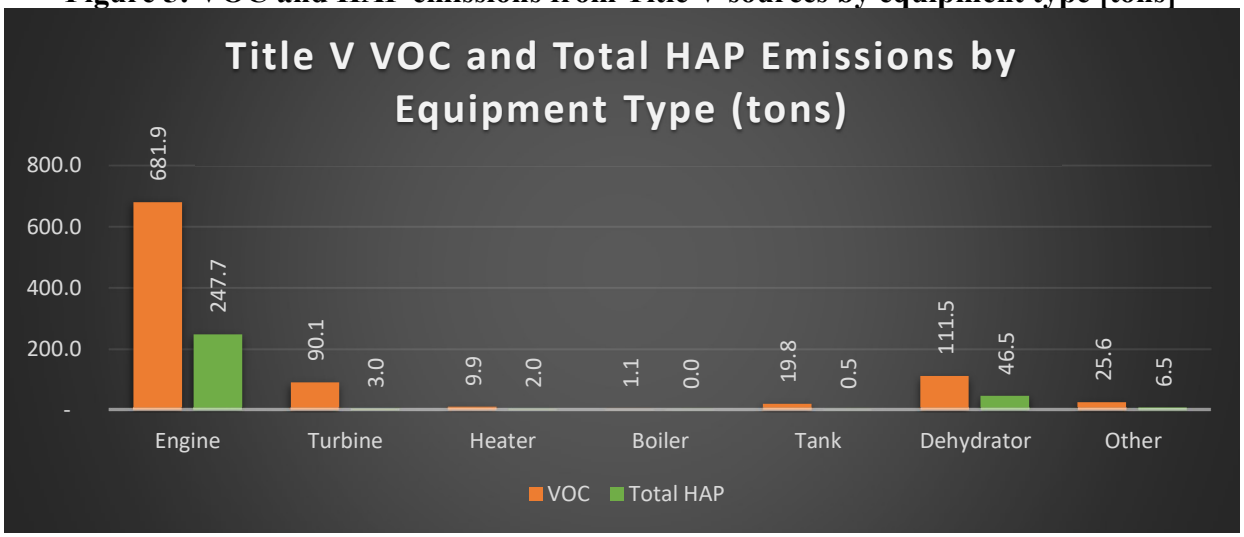


Figure 4: NOx and CO emissions from Title V sources by equipment type [tons]



*"Other" includes emissions from amine units, excess emission events, blowdowns, maintenance, and fugitive emission sources

Figure 5: VOC and HAP emissions from Title V sources by equipment type [tons]



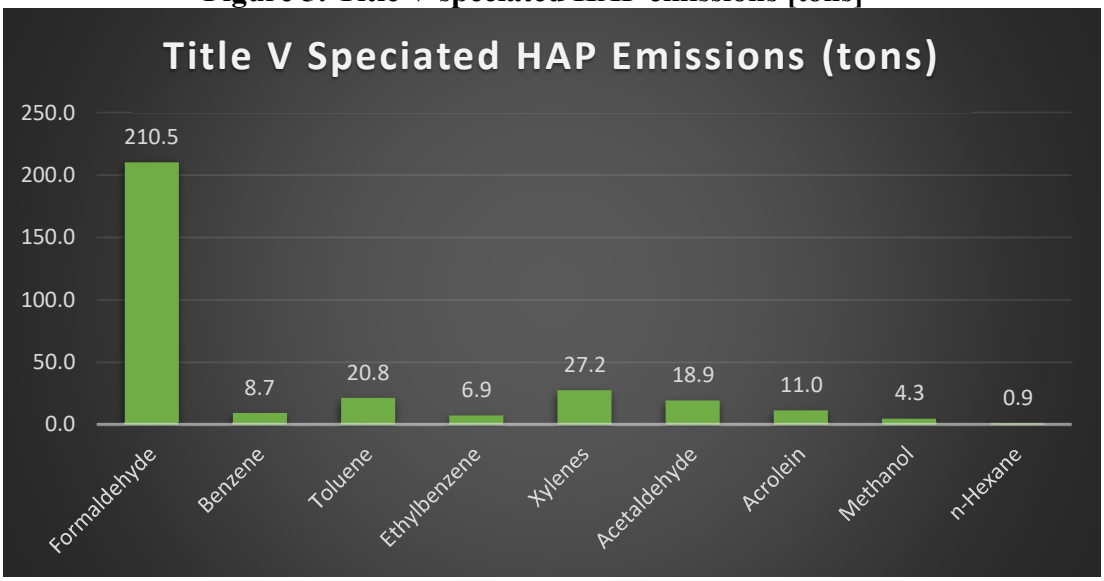
*"Other" includes emissions from amine units, excess emission events, blowdowns, maintenance, and fugitive emission sources

Speciated HAP emissions from Title V sources are displayed below in Table 2 and Figure 5.

Table 2: Title V HAP emissions [tons]

Pollutant	Formaldehyde	Benzene	Toluene	Ethylbenzene	Xylenes	Acetaldehyde	Acrolein	Methanol	n-Hexane
Emissions	210.5	8.7	20.8	6.9	27.2	18.9	11.0	4.3	0.9

Figure 5: Title V speciated HAP emissions [tons]



2. Minor Oil and Gas Point Sources

The Tribal Minor New Source Review (TMNSR) permitting program is found at 40 CFR Part §49.151 through §49.164.[3] The TMNSR permitting program includes new or modified source permitting, permits by rule, and a registration program. For the purposes of this inventory, two main categories of emission sources under this program were considered: a.) Permitted TMNSR oil and gas sources, and b.) Registered TMNSR Oil and Gas Sources.

The emission thresholds for the TMNSR permitting program are located at 40 CFR Part §49.153. Minor sources with emissions less than the levels displayed in Table 3 below are not required to obtain a permit or register under the program.

The emission thresholds from 40 CFR Part §49.153 are displayed below in Table 3.

Table 3: 40 CFR Part 49 Minor New Source Review Program Emissions Thresholds

Regulated NSR Pollutant	Minor NSR Thresholds for Attainment/ Unclassifiable [tpy]
Carbon Monoxide (CO)	10
Nitrogen Oxides (NO_x)	10
Sulfur Dioxide (SO_2)	10
Volatile Organic Compounds (VOC)	5
PM Total	10
PM_{10}	5
$PM_{2.5}$	3
Lead	0.1
Fluorides	1
Sulfuric Acid Mist	2
Hydrogen Sulfide (H_2S)	2
Total Reduced Sulfur (including H_2S)	2
Reduced Sulfur Compounds (including H_2S)	2
Municipal Waste Combustor Emissions	2
Municipal Solid Waste Landfill Emissions (measured as non-methane organic compounds)	10

A. Synthetic minor Oil and Gas Sources

Description of Sources

This category reflects larger emission sources that would be subject to either the Prevention of Significant Deterioration (PSD), Title V operating permit program, or both programs absent enforceable emission limitations to reduce the source's PTE. These types of permits are often referred to as "synthetic minor permits".

[3] 40 CFR Part 49 - Indian Country: Air Quality Planning and Management. (2020). U.S. Government Publishing Office. Retrieved from http://www.ecfr.gov/cgi-bin/text-idx?SID=bc4187dbf0b08beb092efe4251fe4493&mc=true&tpl=/ecfrbrowse/Title40/40cfr49_main_02.tpl

During calendar year 2020, eleven sources on the Reservation operated under TMNSR permits. Of the eleven sources in this category, nine sources are natural gas compressor stations, and one source is a natural gas processing plant. Five sources have permits to reduce emissions below Title V permitting thresholds and six sources have permits for various other reasons.

Data Collection

Only the five oil and gas sources with TMNSR permitted emissions below the Title V permitting thresholds were included in this category to avoid double counting emissions. Emissions from the remaining six oil and gas sources, which also hold Title V operating permits issued by the Tribe, were already accounted for under the Title V Oil and Gas Sources category of this inventory.

Synthetic minor sources are required to submit annual emissions inventories to EPA Region 8 for the pollutants regulated under each permit and emissions data was collected directly from the annual emissions inventories submitted for calendar year 2020[4]. For the pollutants and emission units that were not reported to EPA Region 8, AQP calculated emissions or utilized data that was submitted for its 2017 emission inventory. If actual operating hours were not available, maximum operating hours were used. This data collection methodology adheres to the EPA level II EI guidelines for using measured data when available.

Emissions

Total 2020 criteria pollutant, HAP, and GHG emissions from permitted TMNSR oil and gas sources on the Southern Ute Indian Reservation are presented below in Table 4.

Table 4: Criteria Pollutant, HAP, and GHG emissions for synthetic minor sources [tons]*

Pollutant	NOx	CO	VOC	PM	SO2	Total HAP	GHG (CO2e)
Emissions	253.9	137.5	126.2	3.8	5.9	29.7	69931.4

*GHG emissions reported in tonnes.

Total criteria pollutant and HAP emissions from synthetic minor sources on the Southern Ute Indian Reservation by equipment type are presented below in Figure 6, Figure 7, and Figure 8.

Figure 6: Criteria pollutant and HAP emissions from synthetic minor sources [tons]

[4] Emissions from Southern Ute Indian Tribe (2021). CY 2020 EPA TMNSR Fee Forms.

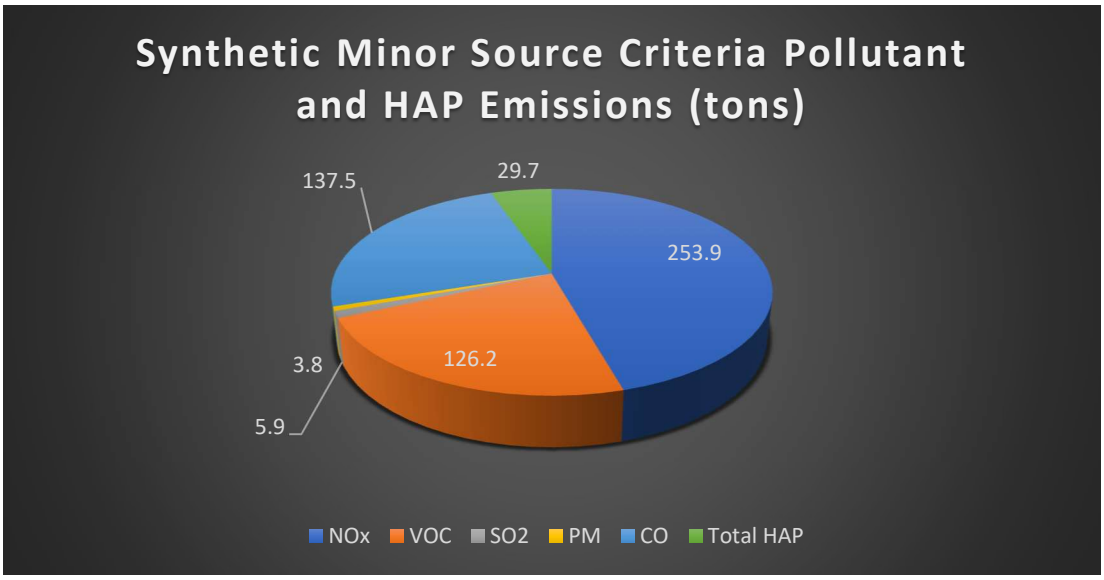
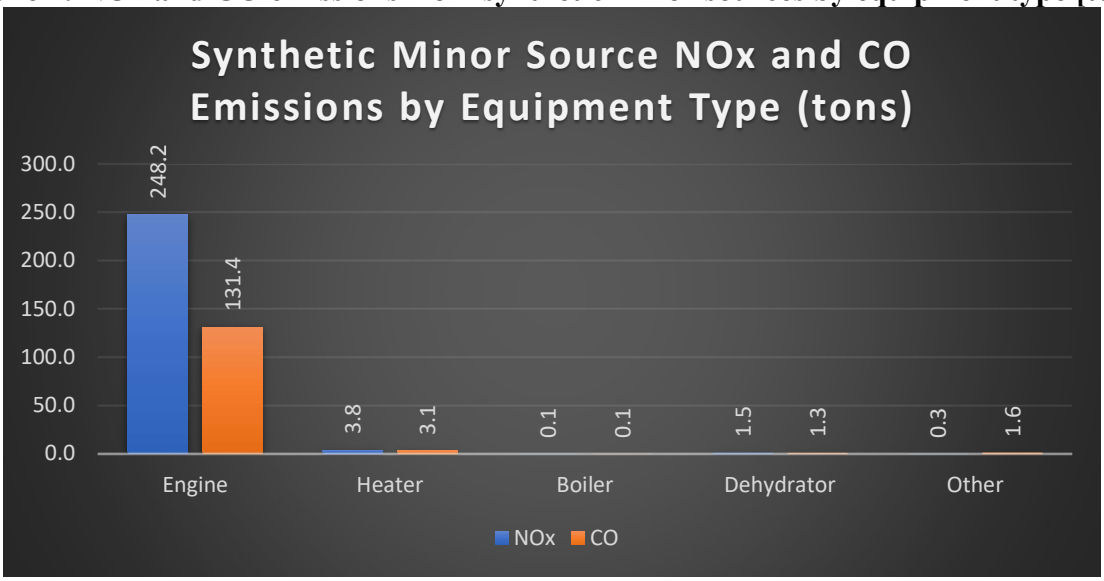
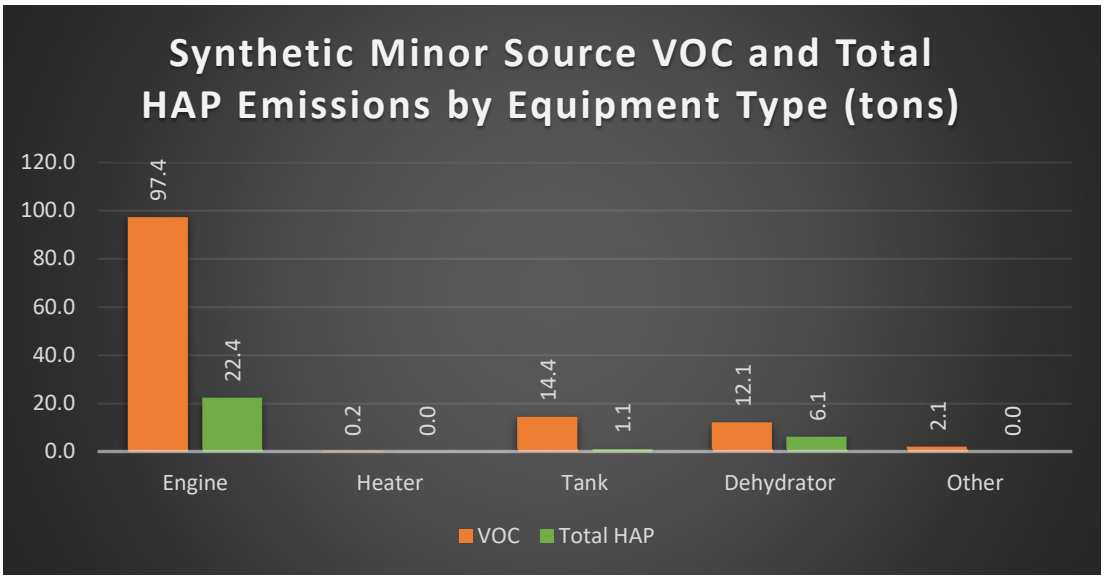


Figure 7: NOx and CO emissions from synthetic minor sources by equipment type [tons]



*"Other" includes emissions from insignificant emission units

Figure 8: VOC and HAP emissions from synthetic minor sources by equipment type [tons]



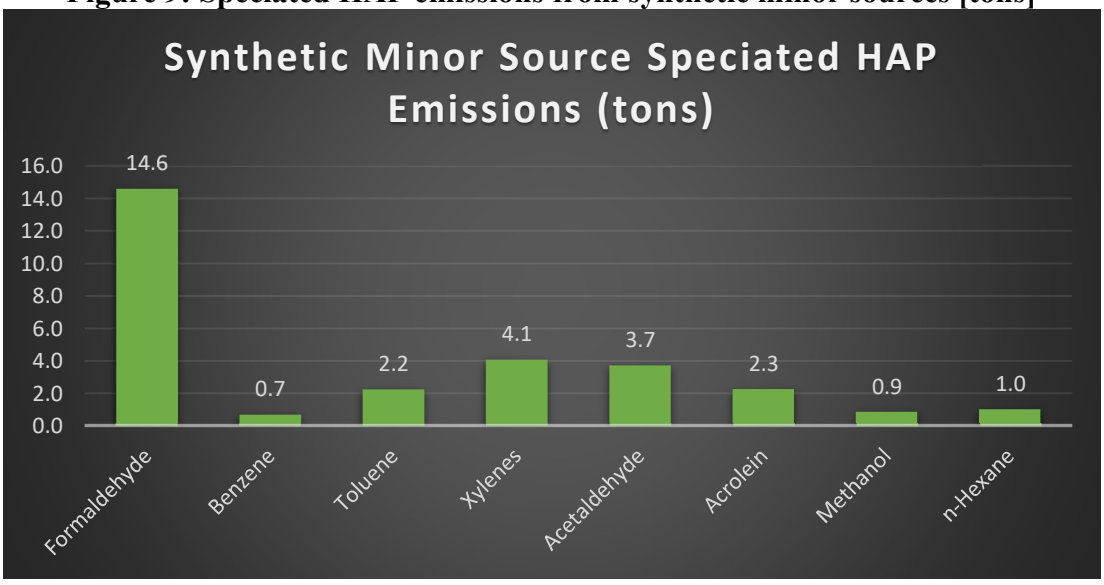
*"Other" includes emissions from insignificant emission units

Total 2020 speciated HAP emissions from synthetic minor sources on the Southern Ute Indian Reservation are displayed below in Table 5 and Figure 9.

Table 5: Speciated HAP emissions from synthetic minor sources [tons]

Pollutant	Formaldehyde	Benzene	Toluene	Xylenes	Acetaldehyde	Acrolein	Methanol	n-Hexane
Emissions	14.6	0.7	2.2	4.1	3.7	2.3	0.9	1.0

Figure 9: Speciated HAP emissions from synthetic minor sources [tons]



B. Registered Tribal Minor New Source Review Oil and Gas Sources
Description of Sources

The TMNSR program required operators of true minor sources, as defined in §49.152, to register each oil and gas source with EPA Region 8 by no later than March 1, 2013. Existing oil and gas sources constructed or modified after March 1, 2013, but before October 3, 2016 were also required to register. All oil and gas sources constructed after March 1, 2013 are required to apply for a site-specific TMSNR permit or comply with the Oil and Gas Federal Implementation Plan for Indian Country at 40 CFR Part 49, Subpart C.

For CY 2020, the AQP had record of 238 active oil and gas source registrations for the Reservation.[5] The registrations included source locations, emission unit descriptions, and actual emissions calculations. All of the registered sources are natural gas production sources, primarily well-sites. Certain non-oil and gas sources, such as hot mix asphalt plants and stone quarrying, crushing and screening operations, also required registration with the EPA under the TMNSR program, but to date, no such sources have been registered. Presumably, non-oil and gas sources that did not register with the EPA may exist on the Reservation, and this issue will be addressed below in the data collection section.

Data Collection

For the purposes of this emission inventory section, only emissions from true minor sources were included. Sources with Title V operating permits or synthetic minor permits were not required to register under 40 CFR Part 49; therefore, there is little risk of double counting emissions from these sources. Emissions from Title V sources and synthetic minor sources were assessed separately, as discussed in Chapter IV Section 1 and 2A of this report.

Due to the potential for registration information to be stale or out of date, the AQP issued a mandatory Clean Air Act Section 114 ICR in June 2021 to obtain updated and reconciled registration data for true minor sources from each facility operator. The ICR included data for registered oil and gas sources. Specifically, the ICR requested reconciliation of the operational status of each previously registered true minor source, equipment located at each source, and the actual emissions for calendar year 2020.

The ICR also requested information that was exempted from TMNSR registration including emissions estimates for engines less than or equal to 50-hp and facility-wide emissions of HAP and GHG. It was anticipated that the ICR could also result in emissions reporting by sources that had never registered with the EPA. This data collection methodology adheres to the EPA level II EI guidelines for utilizing measured data when available.

Emissions

[5] Southern Ute Indian Tribe. (2021). Information Collection Request.

Total 2020 emissions of criteria pollutants, HAP, and GHG from true minor sources on the Reservation are displayed below in Table 6.

Table 6: Criteria pollutant and HAP emissions from true minor sources [tons]*

Pollutant	NOx	CO	VOC	PM	SO2	Total HAP	GHG (CO2e)
Emissions	4,575.2	3,248.1	834.5	42.8	16.1	291.0	1,568,843.6

*GHG emissions reported in metric tonnes.

Total 2020 criteria pollutant and HAP emissions from true minor sources on the Reservation by equipment type are displayed below in Figures 10 through 12. GHG emissions from true minor sources are displayed below in Figure 13.

Figure 10: Criteria pollutant and HAP emissions from true minor oil and gas sources [tons]

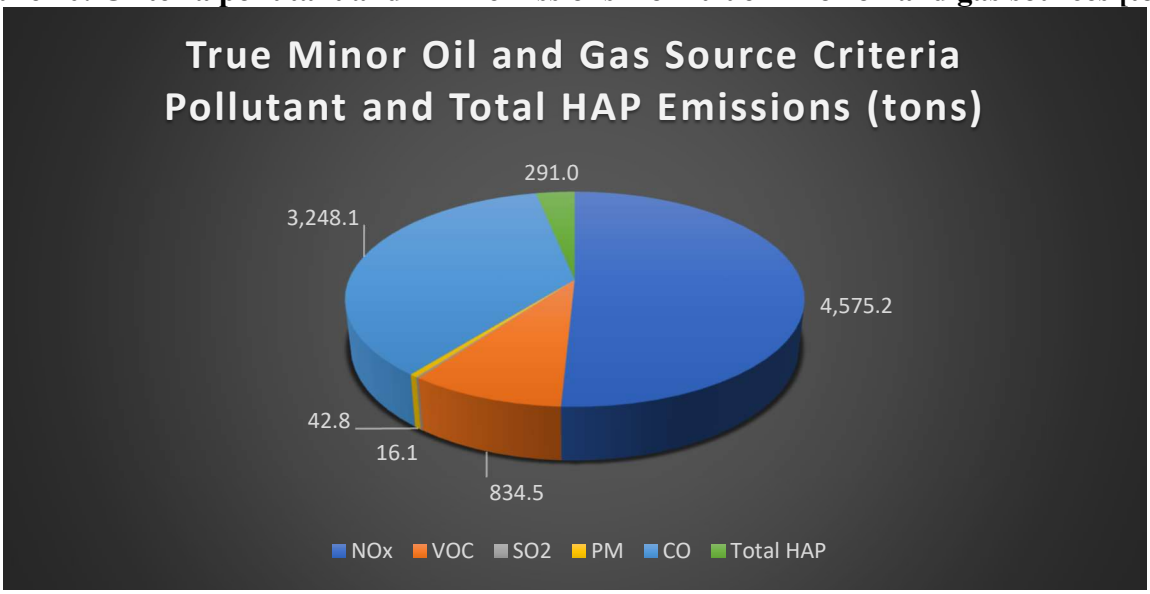
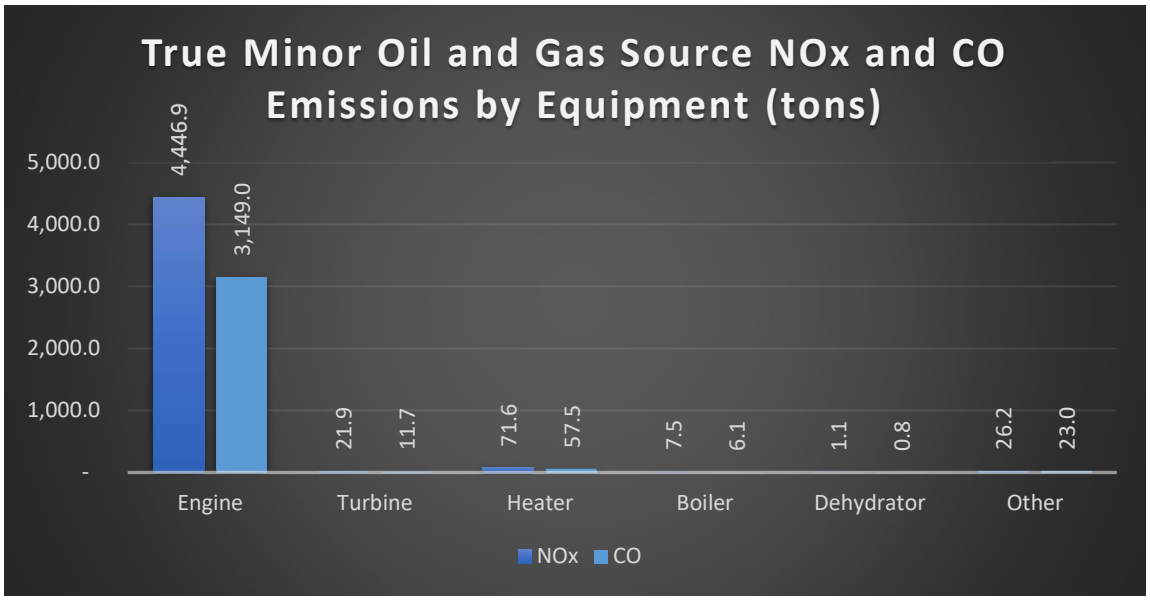
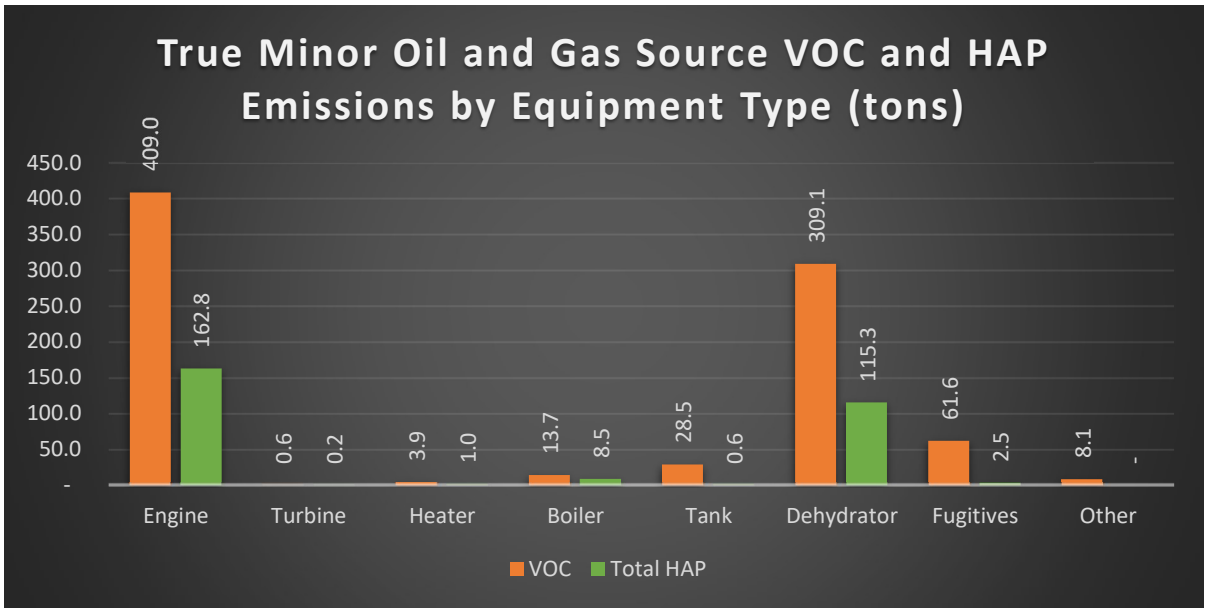


Figure 11: NOx and CO emissions from true minor oil and gas sources by equipment type [tons]



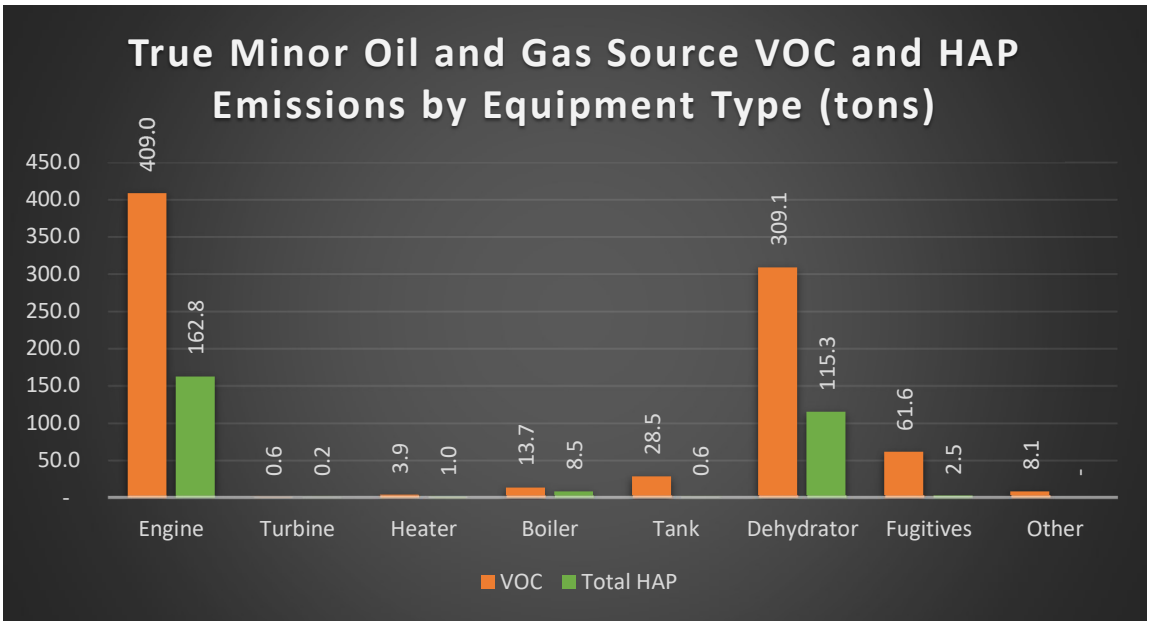
*"Other" consists of combustors, flares, and undefined equipment

Figure 12: VOC and HAP emissions from true minor oil and gas sources by equipment type [tons]



*"Other" consists of combustors, flares, and undefined equipment

Figure 13: GHG emissions from true minor oil and gas sources by equipment type [tonnes]



*"Other" consists of combustors, flares, and undefined equipment

3. Permitted Point Sources

In 2020, the one non-oil and gas point source operating under a TMNSR permit on the Reservation is a gravel pit. The operator reported the facility did not operate in 2020 and therefore, no emissions were reported for the source.

Table 7: Criteria pollutant and HAP emissions from permitted non-oil and gas point sources [tons]

Pollutant	NOx	CO	VOC	PM_{10}	$PM_{2.5}$	PM	SO_2	Total HAP	CO_2e
Emissions	0	0	0	0	0	0	0	0	0

4. Landfill Gas

The Southern Ute Indian Tribe has two Class II municipal solid waste (MSW) landfills within the Reservation boundaries. The first one is the Bondad Recycling Center and Depository (Bondad Landfill) located in Bondad, Colorado and the second one is the Archuleta County Landfill, located south of Pagosa Springs, Colorado. Both MSW disposal sites accept non-hazardous residential, commercial, and industrial waste. The Bondad Landfill is owned and operated by Transit Waste, LLC and has been in operation since 1997. The Archuleta County Landfill is owned and operated by Archuleta County and began operation in 1985. The Bondad Landfill operates under a tribally issued Title V operating permit and the Archuleta County Landfill reports annual landfill gas emissions to the Colorado Department of Public Health and Environment (CDPHE).

Data Collection

The Archuleta County Landfill submitted acceptance volumes for 2018, 2019, and 2020 for input in LandGEM 3.02 with a density 0.79 Megagram/cubic yard. The density was estimated from the reported Megagrams per cubic yard for the years 2013 through 2015. All reports were previously submitted by Archuleta County to the CDPHE. Emissions data for the Bondad Landfill were directly obtained from the CY 2020 Title V emissions fee form submitted to the Tribe.

Emission Calculation Methodology

Emissions for the Archuleta County landfill were estimated using the EPA's MSW landfill emissions model, LandGEM version 3.02 (LandGEM).[6] Emissions data for the Bondad Landfill were obtained from the CY 2020 Title V emissions fee form submitted to the Tribe by Transit Waste, LLC, who ran LandGEM to estimate emissions from this facility. The LandGEM model estimates total landfill gas, non-methane organic compounds (NMOC), and hazardous air pollutants (HAP).

The LandGEM model is based on a first-order decomposition rate equation for quantifying emissions from the decomposition of landfilled waste in MSW landfills.

$$Q_{CH_4} = \sum_{i=1}^{n} \sum_{j=0.1}^{1} kL_0 \left(\frac{M_i}{10} \right) e^{-kt_{ij}}$$

Where:

Q_{CH4} = annual methane generation in the year of calculation (m^3/year)
i = 1 year time increment
n = (year of the calculation) – (initial year of waste acceptance)
j = 0.1 year time increment
k = methane generation rate (year-1)
Lo = potential methane generation capacity (m^3/Mg)
M_i = mass of waste accepted in the i^{th} year (Mg)
t_{ij} = age of the j^{th} section of waste mass M_i accepted the i^{th} year (decimal years, e.g., 3.2 years)

LandGEM Inputs and Assumptions

Complex microbial and biochemical reactions occur within the landfill's interior after the waste has been deposited. The two primary constituents of landfill gas (LFG) are methane (CH_4) and carbon dioxide (CO_2). LFG also contains small amounts of non-methane organic

[6] U.S. EPA - Landfill Gas Emissions Model. (2021). Retrieved from https://www.epa.gov/catc/clean-air-technology-center-products#software.

compounds, which includes VOC, HAP, and GHG. LandGEM estimates the LFG from anaerobic decomposition of the waste with CH_4 and CO_2 content between 40 and 60 percent. The LandGEM default used for methane is 50 percent by volume (the model default value). The production of LFG is a continuous process until microbial reactions are limited by substrate or moisture. Other factors include climate, moisture conditions, and types of solid waste accepted (degradable vs. inert).

Parameters for climatic conditions used in the LandGEM model were a k-value of 0.02 $year^{-1}$ (an arid area that receives less than 25 inches of rain annually) and a L_o-value of 170 cubic meter per megagram. The VOC concentrations are assumed to be 39 percent of NMOC concentrations, consistent with the footnote C Table 2.4-2 of the EPA's publication titled *AP-42, Fifth Edition Compilation of Air Emission Factors* (EPA AP-42).[7] HAP emissions for the Archuleta County Landfill are from the LandGEM report using default emissions factors from EPA AP-42. The total estimated emissions of LFG were estimated using the flow rate and molecular weights.

Emissions

The estimated LandGEM emissions for Bondad Landfill were provided to the Tribe in a Title V emissions fee form package submitted by Transit Waste for calendar year 2020. Emissions estimates for Archuleta County Landfill were calculated by the Tribe using LandGEM and the waste acceptance rates and waste-in-place data values for 2018-2020 along with the historical data submitted

To avoid double counting emissions from the Bondad Landfill, emissions from Bondad Landfill were only included in the Landfill gas emission totals and not included in the Title V emission totals presented in Section IV.1 of this report.

Total refuse in place in tons and total emissions of GHG, VOC and HAP from MSW landfills on the Reservation for 2020 are displayed below in Table 8 and Figure 14.

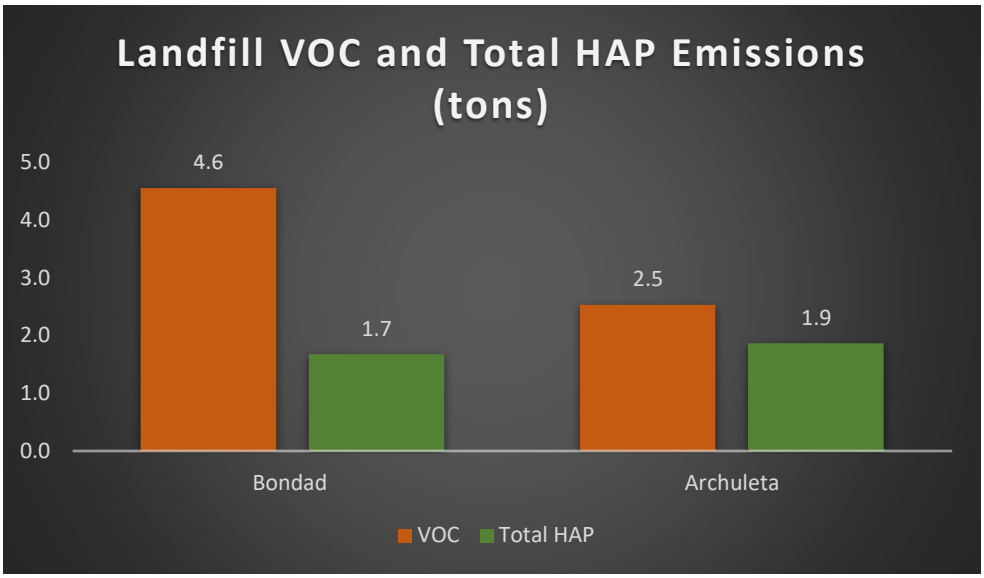
Table 8: Municipal solid waste landfill refuse in place [tons] and emissions [tons]*

	Refuse in Place	GHG	VOC	HAPs[1]
Bondad Landfill	1,667,802	4,846.5	4.6	1.7
Archuleta County Landfill	548,775	18,380.2	2.5	1.9
Totals	**2,216,577**	**23,226.7**	**7.1**	**3.6**

*An insignificant quantity of double counting of VOCs occurs because many reported HAPs are also considered VOCs.

Figure 14: Municipal solid waste landfill emissions [tons]

[7] U.S. Environmental Protection Agency. (2020). *AP-42: Compilation of Air Emission Factors*. Retrieved from https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.



5. Airports

There are three airports located within the Reservation: the Durango-La Plata County Airport, the Animas Air Park, and the Animas Air Park Helipark.

Data Collection

The AQP obtained CY 2018 data from EPA's National Emissions Inventory database (NEI), which includes total landing and take-off cycles (LTOs) and piston and turbine engine emission estimates for the heliport, taxi, and general aviation at the Animas Air Park.[8] The LTOs were from the Federal Aviation Administration (FAA). The methodologies used by EPA to calculate airport emissions are detailed in the Eastern Research Group's document titled *Documentation for Aircraft Component of the National Emissions Inventory Methodology.*[9]

Emissions data for the Animas Air Park and Animas Air Park Heliport were submitted to the NEI by EPA. Emissions data for the Durango-La Plata airport were reported to the NEI by the CDPHE.

Assumptions

[8] U.S. EPA National Emission Inventory Emissions Inventory System. (2020). Retrieved from https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei.

[9] Eastern Research Group. (2001, January). Documentation for Aircraft Component of the National Emissions Inventory Methodology. (ERG No. 0245.03402.011).

Calendar year 2020 airport emissions are assumed to be similar to emissions from the airports during CY 2018.

Emissions

Total criteria pollutant and HAP emissions from airports on the Reservation for 2020 are displayed in Table 9 and Figure 15 and Figure 16 below.

Table 9: Criteria pollutant and HAP emission from airports [tons]*

	NOx	VOC	SO_2	$PM_{2.5}$	PM_{10}	Lead	CO	Total HAP
Animas Air Park Heliport	0.01	0.01	0.00	0.01	0.01	0.00	0.27	0.00
Animas Air Park	0.40	0.84	0.08	0.51	0.66	0.03	30.93	0.31
Durango-La Plata County	36.07	13.09	4.94	3.29	3.83	0.1	185.91	3.59
Totals	**36.47**	**13.94**	**5.02**	**3.81**	**4.50**	**0.13**	**217.11**	**3.90**

*Emissions estimations for airports are from the 2018 EPA National Emission Inventory Database and assumed to be realistic estimations of airport emissions for 2020.

Figure 15: CO and NOx emissions from airports [tons]

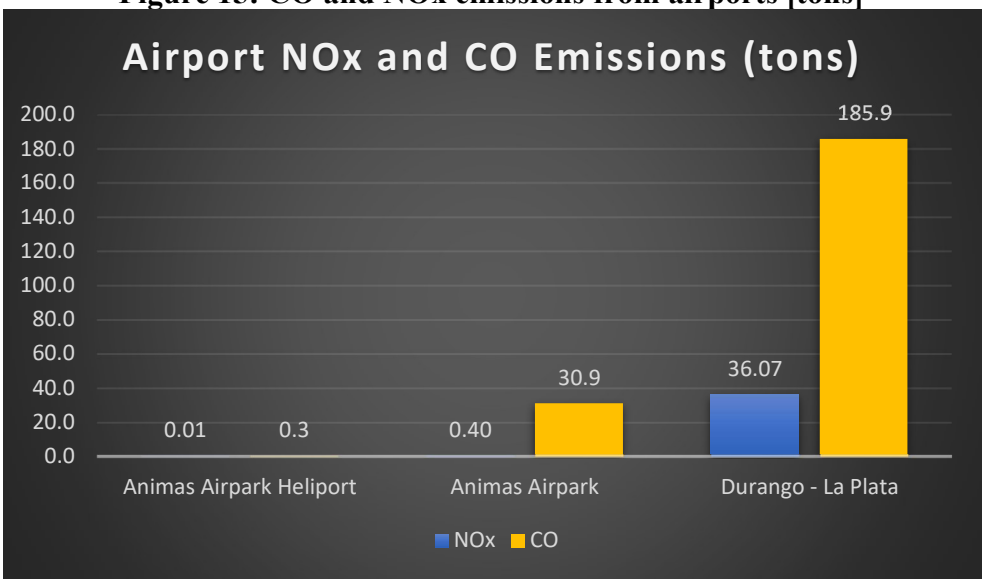
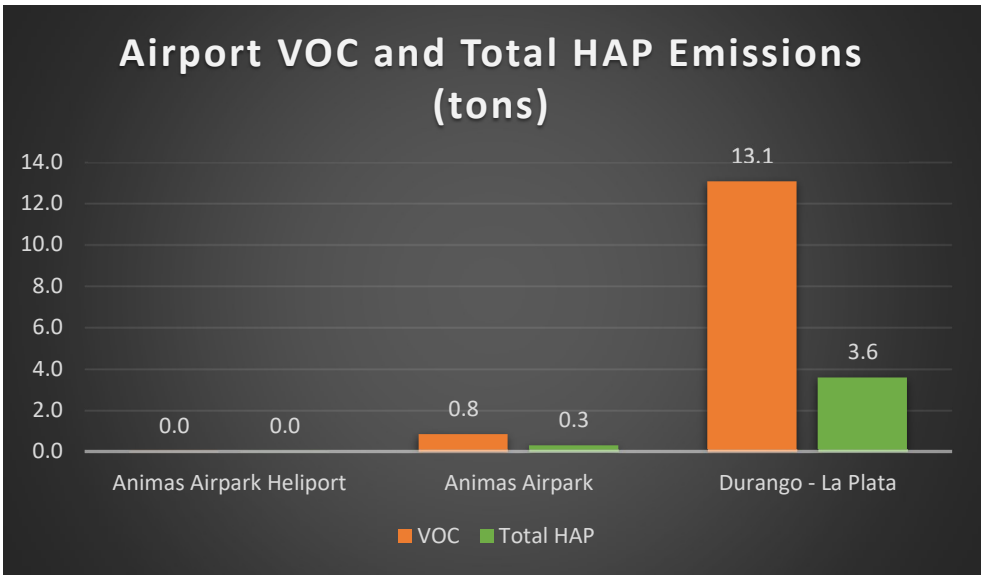


Figure 16: VOC and Total HAP emissions from airports [tons]



V. Non-Point Sources

1. Small Oil and Gas Sources

Description of Sources

For the purpose of this EI small oil and gas sources are defined as: *oil and gas sources with emissions below the thresholds that require registration under the EPA Tribal Minor New Source Review (TMNSR) Program at 40 CFR Part 49*. The majority of these sources are natural gas well sites, which are comprised of artificial lift engines, separators, filter coalescers, compressor engines, reciprocating compressors, lube oil tanks, tank heaters, dehydration units, and produced water, condensate, and oil tanks.

Data Collection

Source information for small oil and gas sources was obtained through a mandatory Clean Air Act Section 114 ICR issued by the AQP in June of 2021 to each known operator with sources operating on the Reservation. To identify the operators within the Reservation and estimate the total number of small oil and gas sources on the Reservation, the AQP compiled site and ownership data from the COGCC and Drilling Edge databases.[10,11]

The ICR was the basis for collecting the information necessary to calculate emissions from small oil and gas sources and required each recipient to provide actual equipment counts

[10] COGCC. (2020). Production Data. La Plata. Retrieved from http://cogcc.state.co.us/data2.html#/downloads.

[11] Drilling Edge Database (2016). Retrieved from http://www.drillingedge.com/colorado.

and production information. Data was requested for each company's operations on the Reservation in its entirety and not specific to any single source location.

Completed ICRs were submitted by 27 of the 32 (84%) companies that reported production on the Reservation in CY 2020 to the COGCC database. The completed ICRs accounted for 2,570 of the 2,582 (99.5%) known small oil and gas sources on the Reservation. The AQP used 2017 ICR submitted information for the remaining unreported sources.

Calculation Methodology

The AQP calculated emissions for small oil and gas sources on an equipment basis using measured data, widely accepted emission factors and emission calculation methodologies, the equipment counts reported in the ICR, and CY 2020 production data from the COGCC. Descriptions of how emissions were calculated for each equipment type are included later in this section.

Emissions

Criteria pollutant, HAP, and GHG emission estimations from small oil and gas sources on the Reservation in 2020 are displayed below in Table 10.

Table 10: Emissions from small oil and gas sources [tons]*

Pollutant	NOx	VOC	SO2	PM	CO	Total HAP	GHG
Emissions	11,664.0	798.8	5.6	183.8	9,716.6	233.9	1,575,054.1

*GHG emissions reported in metric tonnes.

Criteria pollutant, HAP, and GHG emissions from small oil and gas sources on the Reservation by equipment type are displayed below in Figures 17 through 20.

Figure 17: Criteria pollutant and HAP emissions from small oil and gas sources [tons]

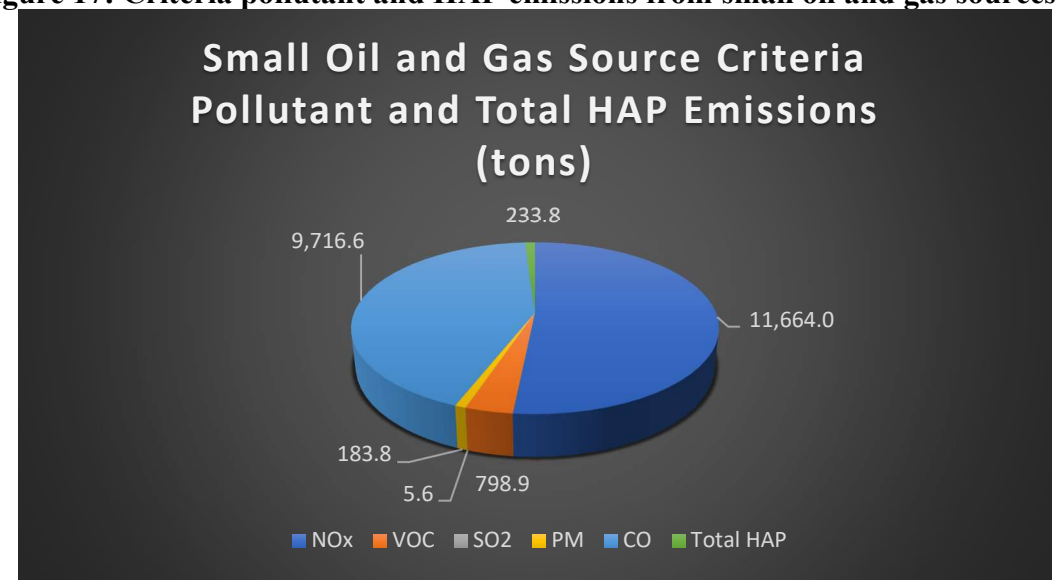


Figure 18: NOx and CO emissions from small oil and gas sources by equipment type [tons]

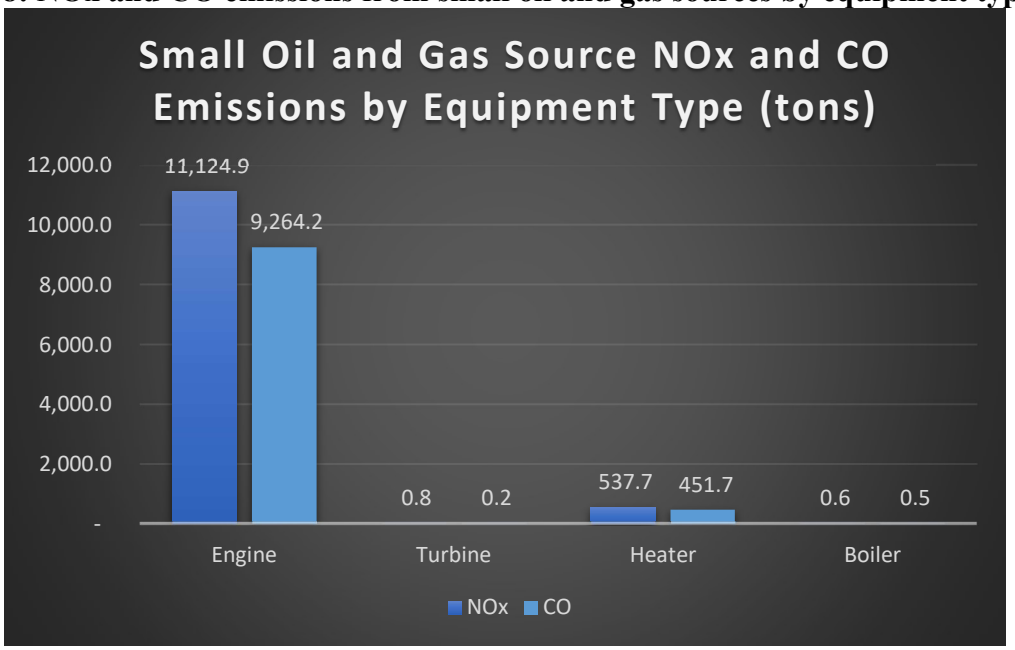


Figure 19: VOC and HAP emissions from small oil and gas sources by equipment type [tons]

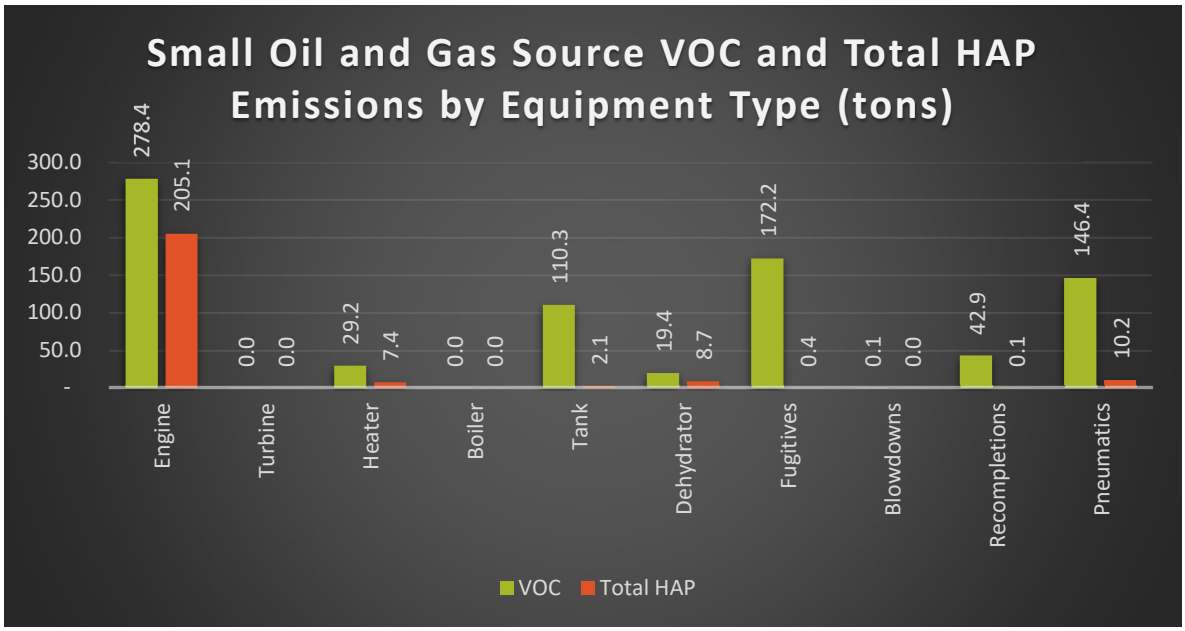
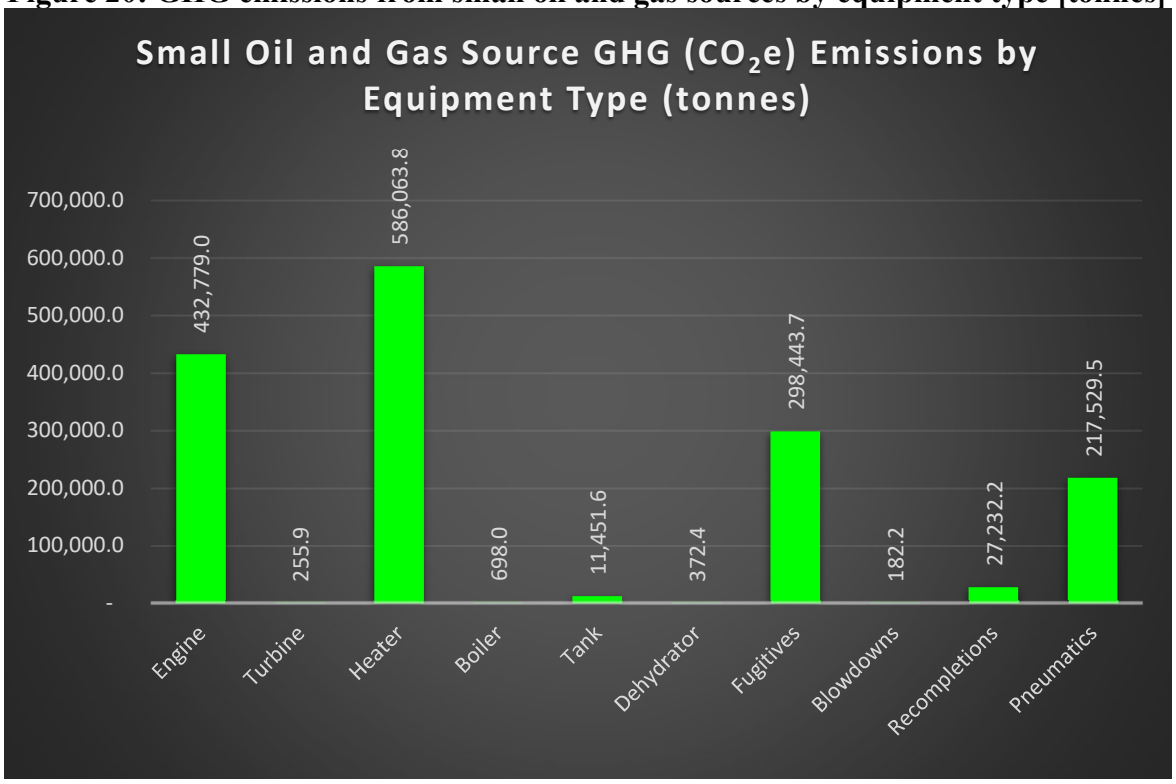


Figure 20: GHG emissions from small oil and gas sources by equipment type [tonnes]

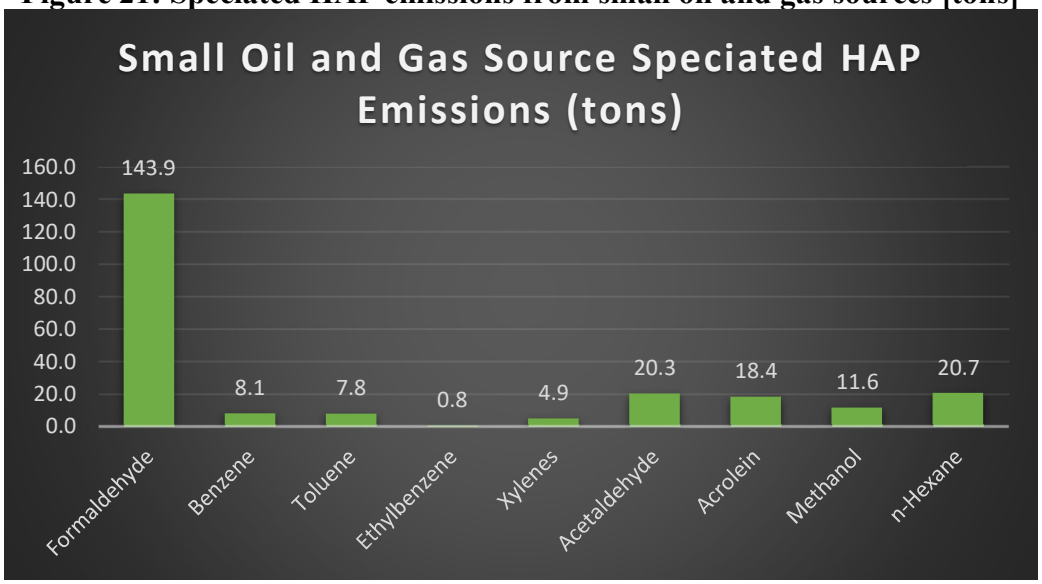


2020 Speciated HAP emissions are displayed below in Table 11 and Figure 21.

Table 11: Speciated HAP emissions from small oil and gas sources [tons]

Pollutant	Formaldehyde	Benzene	Toluene	Ethylbenzene	Xylenes	Acetaldehyde	Acrolein	Methanol	n-Hexane
Emissions	143.9	8.1	7.8	0.8	4.9	20.3	18.4	11.6	20.7

Figure 21: Speciated HAP emissions from small oil and gas sources [tons]



A. Natural Gas-Fired Reciprocating Internal Combustion Engines

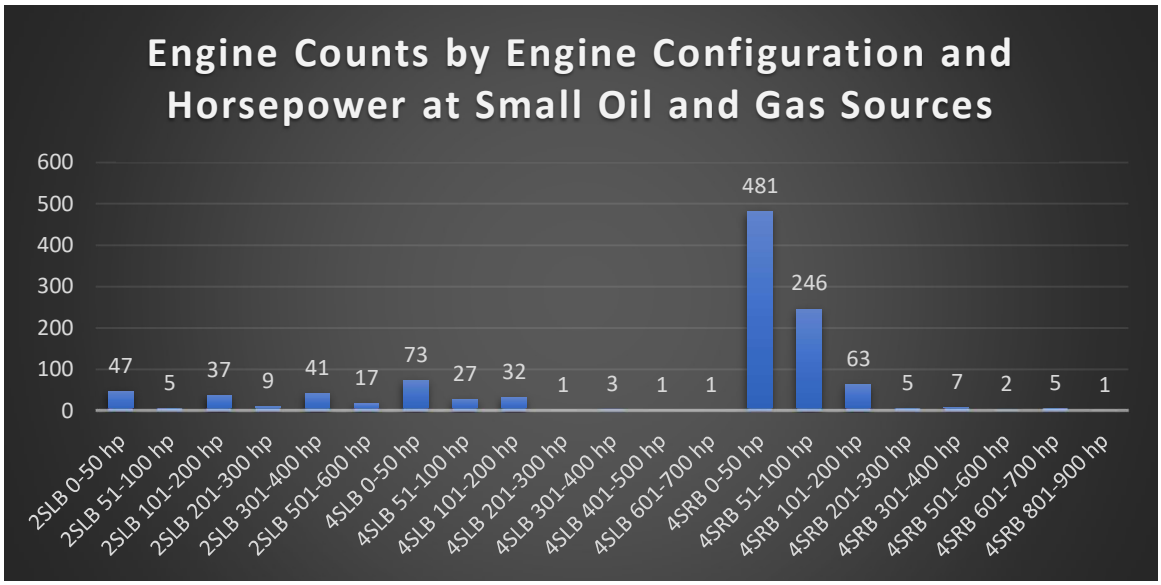
Description of Units

Natural gas-fired spark-ignited reciprocating internal combustion engines (RICE) are used by the oil and gas industry to compress natural gas, pump liquids, generate electricity, and to provide artificial lift. The most prevalent pollutants emitted from natural gas-fired RICE are NOx, CO, VOC, and HAP.

Data Collection

The ICR required recipients to list the total number of natural gas-fired spark-ignition and compression ignition RICE operated by their company on the Reservation. Engines were reported according to horsepower range, and engine configuration. Engine configurations included two-stroke lean-burn (2SLB), four-stroke lean-burn (4SLB), four-stroke rich-burn (4SRB), and diesel. The ICR included assumed values for engine operating hours and average brake specific fuel consumption (BSFC) and provided recipients the option to provide values more representative of their operations. A summary of reported engines at small oil and gas sources on the Reservation in 2020 are displayed below in Figure 22.

Figure 22: Engine counts by engine configuration and horsepower at small oil and gas sources



Emission Calculation Methodology

Criteria Pollutant and HAP Emissions:

Criteria pollutant and HAP emissions were calculated for each engine configuration and horsepower rating category reported in the ICR. Emission calculations were based on the maximum horsepower of each reported horsepower range, the appropriate emission factors for stationary internal combustion sources from Chapter 3 of EPA AP-42, an assumed BSFC of 7,500 Btu/hp-hr (if the operator did not input anything more representative of their operating conditions), an assumed 100% engine operating load, and assumed operating schedule of 8,760 hours per year (if the operator did not input a different number of annual operating hours). The assumed BSFC value was derived by averaging the BSCF from all natural gas-fired engines in the Caterpillar Gas Engine Rating Pro software.[12] All emissions were calculated for uncontrolled operation. The natural gas on the Reservation contains negligible amounts of sulfur, therefore SO_2 emissions from engines are minimal.

GHG Emissions:

Greenhouse gas emissions were calculated using the default values from Tables C-1 and C-2 of 40 CFR Part 98, Subpart C and the same methodology as used for criteria pollutants and HAP.[13]

[12] Caterpillar, Inc. (2015). Gas Engine Rating Pro Emissions Estimation Software. Retrieved from http://www.cat.com/en_US/articles/solutions/oil-gas/gas_engine_rating_pro.html.

[13] 40 CFR Part 98 - Mandatory Greenhouse Gas Reporting. (2021). U.S. Government Publishing Office. Retrieved from http://www.ecfr.gov/cgi-bin/text-idx?SID=32c4baa0d0aff54fa651d1cdb1cd7934&mc=true&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

Example Calculation

Calculation of engine heat rate (MMBtu/hr) using AQP's assumed brake specific fuel consumption (Btu/hp-hr):

HR (MMBtu/hr) = BSFC (7500 Btu/hp-hr)/10^6 x hp

Where:

HR = heat rating (MMBtu/hr)
BSFC = brake-specific fuel consumption
hp = engine horsepower

Engine emission calculation:

tpy = (EF) x HR x OH/2000 pounds/ton

Where:

tpy = tons per year
EF = emission factor (lb/MMBtu)
HR = heat rate
OH = annual operating hours

Example Nox emissions calculation for a 200 hp four-stroke rich-burn engine operating 8,760 hours per year:

tpy = (2.21 lb/MMBtu) x (1.5 MMBtu/hr) x (8760 hr)/2000 lb/ton = 14.52 tpy Nox

Emissions

Total criteria pollutant, HAP, and GHG emissions from natural gas-fired RICE at small oil and gas sources are displayed below in Table 12 and Figures 23 and 24.

Table 12: Natural gas-fired reciprocating internal combustion engine counts and criteria pollutant, HAP, and GHG emissions for small oil and gas sources [tons]*

Engine Configuration and Horsepower (hp)	Number of Engines	NOx	VOC	SO2	PM	CO	Total HAP	GHG
2SLB 0-50 hp	47	170.8	6.5	0.0	4.1	20.8	4.2	5,722.5
2SLB 51-100 hp	5	61.3	2.3	0.0	1.5	7.5	1.5	2,055.0
2SLB 101-200 hp	37	774.3	29.3	0.1	18.8	94.3	18.8	25,948.5
2SLB 201-300 hp	9	270.0	10.2	0.1	6.5	32.9	6.7	9,046.7

2SLB 301-400 hp	41	1,707.8	64.6	0.3	41.4	208.0	41.5	57,232.6
2SLB 501-600 hp	17	1,062.2	40.2	0.2	25.7	129.3	25.8	35,595.9
4SLB 0-50 hp	73	472.4	13.7	0.1	0.0	36.7	8.4	12,301.5
4SLB 51-100 hp	27	361.9	10.5	0.1	0.0	28.1	6.3	9,422.4
4SLB 101-200 hp	32	788.1	22.8	0.1	0.0	61.2	13.7	20,520.4
4SLB 201-300 hp	1	35.7	1.0	0.0	0.0	2.8	0.6	928.6
4SLB 301-400 hp	3	148.7	4.3	0.0	0.0	11.6	2.4	3,872.2
4SLB 401-500 hp	1	59.4	1.7	0.0	0.0	4.6	1.0	1,547.7
4SLB 601-700 hp	1	93.8	2.7	0.0	0.0	7.3	1.6	2,442.9
4SRB 0-50 hp	481	1,715.2	23.0	0.5	14.8	2,887.2	24.3	82,450.5
4SRB 51-100 hp	246	1,785.7	23.9	0.5	15.4	3,005.7	25.3	85,836.0
4SRB 101-200 hp	63	900.9	12.1	0.2	7.7	1,516.5	12.8	43,306.7
4SRB 201-300 hp	5	106.9	1.5	0.0	0.9	183.3	1.5	5,234.7
4SRB 301-400 hp	7	203.3	2.7	0.1	1.7	342.2	2.9	9,771.4
4SRB 501-600 hp	2	87.1	1.2	0.0	0.6	146.6	1.2	4,187.7
4SRB 601-700 hp	5	254.1	3.4	0.1	2.2	427.7	3.6	12,214.3
4SRB 801-900 hp	1	65.3	0.9	0.0	0.6	110.0	0.9	3,140.8
Totals:	**1104**	**11,059.6**	**277.6**	**2.4**	**141.5**	**9,154.2**	**204.2**	**429,638.2**

*GHG reported in metric tonnes.

Figure 23: CO and NOx emission from small oil and gas sources by engine type [tons]

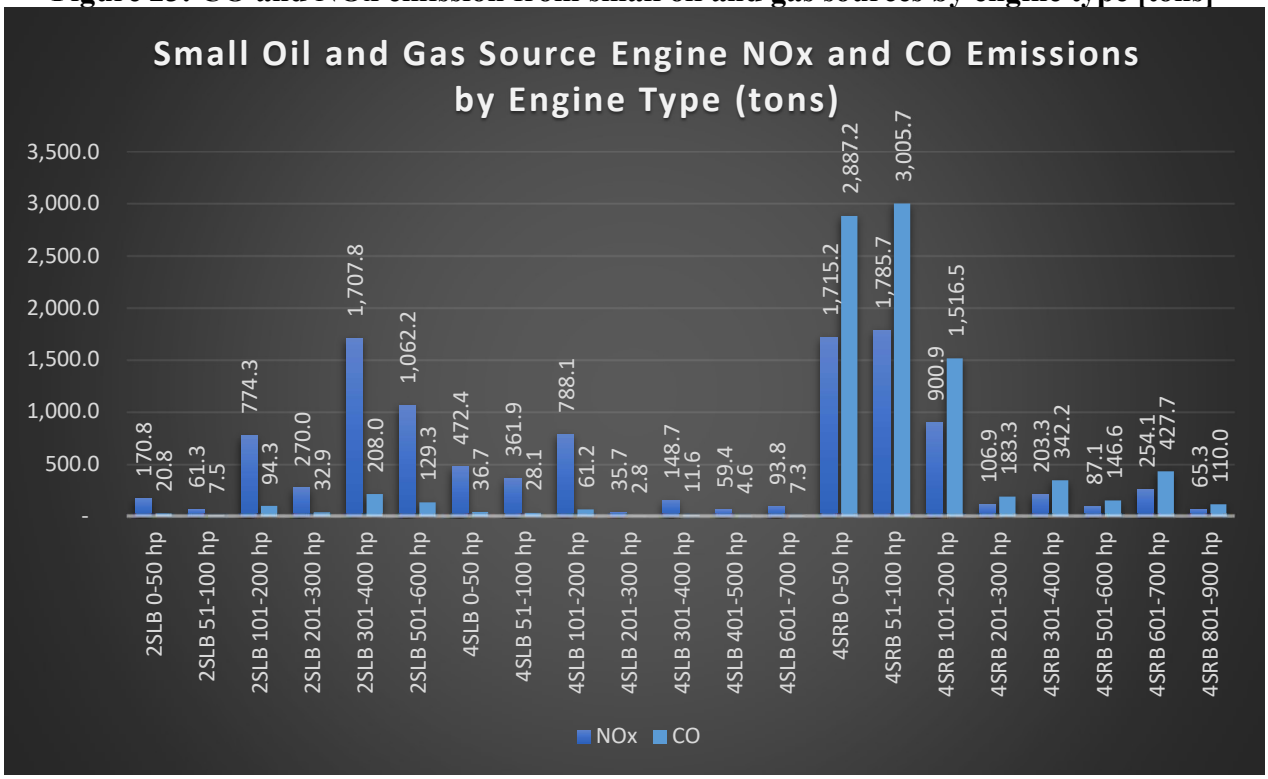
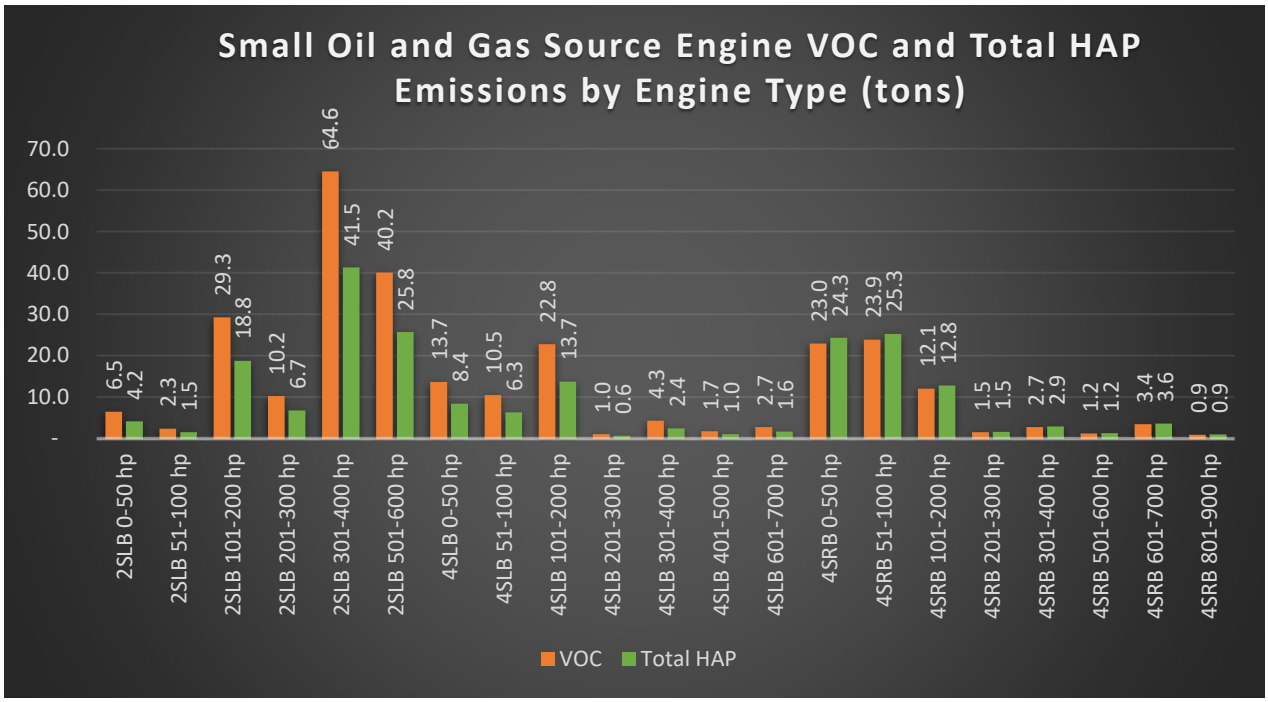


Figure 24: VOC and Total HAP emissions from small oil and gas sources by engine type [tons]



B. Stationary Natural Gas Turbines:

Description of Units

Natural gas-fired stationary turbines are a type of rotary internal combustion engine used by the natural gas industry for natural gas transmission and for electric generation. Turbines operate by introducing compressed air and fuel into a combustion chamber to generate hot gases, which are expanded into the power turbine to rotate the power shaft and create work. Two types of combustion processes are used in turbines, the first being lean-premix staged combustion in which a lean air and fuel mixture is introduced into the combustion chamber, and the second type being diffusion flame combustion where the air and fuel mixing occurs within the combustion chamber. The power shaft is used to run a centrifugal compressor for gas transmission, or to rotate an alternator when used for electric generation.

Data Collection

The ICR required recipients to list the total number of natural gas-fired turbines operated by their company on the Reservation. Turbines were reported according to horsepower or kilowatt range and, turbine configuration. Turbine configurations included uncontrolled, water-steam injection, and lean-premix. The AQP assumed turbines to operate for 8,760 hours per year. Average brake specific fuel consumption (BSFC) was assumed to be 11,000 Btu/hp-hr, as established in the document titled *Stationary*

Combustion Turbines in the United States.[14] If an operator specific BSFC was reported in the ICR, this value was used in place of the assumed BSFC value.

Only one turbine was reported at a small oil and gas source in the ICR. The turbine was a 0-50 hp, lean pre-mix unit, operated 8,760 hours per year, with a BSFC of 11,000 Btu/hp-hr.

Emission Calculation Methodology

Criteria Pollutant and HAP Emissions:

Criteria pollutant and HAP emissions were calculated based on the maximum reported horsepower, emission factors for stationary gas turbines from Chapter 3.1 of EPA AP-42, 100% engine operating load, an operating schedule of 8,760 hours per year and a reported BSFC of 11,000 Btu/hp-hr. The calculation methodology for natural gas turbines is the same methodology used for reciprocating internal combustion engines and displayed in an example calculation earlier in this section. The natural gas on the Reservation contains negligible amounts of sulfur, therefore SO_2 emissions from turbines are minimal.

GHG Emissions:

Greenhouse gas emissions were calculated using the default values from Tables C-1 and C-2 of 40 CFR Part 98, Subpart C and the same methodology as used for criteria pollutants and HAP.

Emissions

Criteria pollutant, HAP, and GHG emissions from natural gas turbines on the Southern Ute Reservation for 2020 are displayed in Table 13.

Table 13: Turbine count and criteria pollutant, HAP, and GHG emissions at small oil and gas sources [tons]*

Turbine configuration and horsepower	Number of turbines	NOx	CO	PM10	VOC	Total HAP	GHG (CO2e)
Lean-Premix 0-50 hp	1	0.77	0.20	0.02	0.01	0.00	255.92

*GHG reported in metric tonnes.

C. Tri-Ethylene Glycol Dehydration Units

Description of Units

[14] McGowin (1973) Stationary Combustion Turbines in the United States.

Tri-ethylene glycol (TEG) dehydration units are commonly used in the natural gas industry to remove entrained water from the natural gas stream to meet pipeline contract water specifications. The dehydration process begins with routing the natural gas stream through TEG in an absorber (or contactor tower) where the entrained water is absorbed by the TEG. During this step, hydrocarbons present in the natural gas stream are also absorbed in the glycol. Following the absorption step, the water saturated (rich) glycol is then distilled to drive off absorbed water before being re-circulated to the absorber. The distillation step results in emissions of VOC and HAP from the reboiler still-vent. The common still-vent HAP emissions are benzene, toluene, ethyl-benzene, and xylene.

Data Collection

The AQP collected dehydration unit counts from the ICR, which required operators to enter the total number of dehydration units operated by their company at small oil and gas sources on the Reservation during calendar year 2020. The ICR included assumed dehydration unit operating parameters and a theoretical extended natural gas analysis, as described later in this section, which could be accepted or overridden with values more representative of the operators' operations. The theoretical extended gas analysis is displayed below in Table 14.

Fifty dehydration units were reported in the ICR submittals and all submittals accepted the AQP's assumed operation and natural gas composition values.

Emissions Calculation Methodology

Emissions for glycol dehydration units were calculated using the GRI-GLYCalc 4.0 model (GLYCalc), the AQP's theoretical values for dehydration unit operating parameters and natural gas composition, and the methodology outlined in the GLYCalc user's manual.[15] GLYCalc is the EPA's preferred method of quantifying emissions from glycol dehydration units for the development of tribal/state/local emissions inventories.[16]

Product of combustion emissions from dehydration unit reboilers were included in the emission totals for heaters and boilers presented in Section V.1.E. of this report to avoid double counting.

[15] Gas Research Institute. (2000). GLYCalc Version 4.0. Retrieved from http://sales.gastechnology.org/000102.html.

[16] U.S. EPA. (1995). Glycol Dehydrator Emissions Test Report and Emissions Estimation Methodology. Retrieved from https://www3.epa.gov/ttn/chief/old/efdocs/glycoldehydratortestreport.pdf.

Table 14: Theoretical extended natural gas analysis – average of 31 natural gas analyses from the Southern Ute Indian Reservation

Component	Average
Methane	92.3814%
Ethane	0.9867%
Propane	0.2291%
Isobutane	0.0349%
n-Butane	0.0468%
Isopentane	0.0107%
n-Pentane	0.0070%
n-Hexane	0.0028%
Carbon Dioxide	6.1663%
Nitrogen	0.1134%
Hydrogen Sulfide	0.0000%
2,2 Dimethylbutane	0.0000%
2,3 Dimethylbutane	0.0000%
Cyclopentane	0.0003%
2-Methylpentane	0.0004%
3-Methylpentane	0.0029%
2,2 Dimethylpentane	0.0012%
Methylcyclopentane	0.0000%
2,4-Dimethylpentane	0.0012%
2,2,3-Trimethylbutane	0.0000%
Benzene	0.0000%
3,3-Dimethylpentane	0.0005%
Cyclohexane	0.0000%
2-Methylhexane	0.0008%
2,3-Dimethylpentane	0.0002%
1,1-Dimethylcyclopentane	0.0000%
3-Methylhexane	0.0000%
1,t-3-Dimethylcyclopentane	0.0002%
1,c-3-Dimethylcyclopentane	0.0000%
3-Ethylpentane	0.0000%
1,t-2-Dimethylcyclopentane	0.0000%
2,2,4 Trimethylpentane	0.0000%
n-Heptane	0.0002%
Methylcyclohexane	0.0028%
Toluene	0.0021%
n-Octane	0.0010%
Ethylbenzene	0.0017%
2,3-Dimethylheptane	0.0001%
m-Xylene	0.0000%
p-Xylene	0.0002%
o-Xylene	0.0003%
n-Nonane	0.0001%
n-Decane	0.0008%
n-Undecane	0.0006%
Total:	100.00%
Total VOC:	0.35%

GRI-GLYCalc Model Input Parameters

The AQP developed assumed dehydration unit operational values for natural gas temperature, pressure, and flowrate by averaging operational information from dehydration units at small oil and gas sources provided by two of the largest operators on the Reservation. An assumed extended natural gas analysis was prepared by averaging 31 individual extended gas analyses from natural gas production sector compressor stations that were reported to the AQP in Title V operating permit applications between 2017 and 2020.

The AQP's assumed values were input into the GLYCalc emissions model using a pipeline water content specification of seven pounds of water per MMscf of natural gas, 1.5% H_2O lean glycol, and assuming uncontrolled operation with no flash tank.
The assumed GLYCalc input parameter values are provided below in Table 15.

Table 15: GRI-GLYCalc Model input parameters for TEG Dehydration units at small oil and gas sources

Wet Gas Temperature [°F]	68.5
Wet Gas Pressure [psig]	353.5
Dry Gas Flowrate/ Throughput [MMscf/day]	0.9
Lean Glycol Water Content [weight % H2O]	1.5
Glycol Pump Type	Electric/ Pneumatic
Pipeline Water Content Specification [lb H2O/MMscf]	7.0

GRI-GLYCalc Model Emissions Output:

Fifty dehydration units were reported for small oil and gas sources in the ICR submittals and all dehydration unit emissions were calculated using the AQP's default GRI-GLYCalc emissions report. The GRI-GLYCalc report was applied once to each of the 50 dehydration units reported in the ICR, and then summed to derive a reservation-wide emissions estimate for glycol dehydration units located at small oil and gas sources.

No operator specific GLYCalc reports or dehydration unit emission estimations were provided in the ICR submittals.

Modeled GRI-GLYCalc emissions for a single TEG dehydration unit and using the AQP's assumed model inputs are provided in Table 16.

Table 16: GRI-GLYCalc Model emissions output for TEG Dehydration units [tons]

Pollutant	Uncontrolled Emissions
Methane	0.2341
Ethane	0.0226
Propane	0.0211
Isobutane	0.0076
n-Butane	0.0156
Isopentane	0.0057
n-Pentane	0.0050
Cyclopentane	0.0000
n-Hexane	0.0080
Cyclohexane	0.0048
Other Hexanes	0.0000
Heptanes	0.0000
Methylcyclohexane	0.0097
2,2,4-Trimethylpentane	0.0002
Benzene	0.0237
Toluene	0.0796
Ethylbenzene	0.0122
Xylenes	0.0998
C8+ Heavies	0.1469
Total HC Emissions	**0.6966**
Total VOC Emissions	**0.4399**
Total HAP Emissions	**0.3849**
Total BTEX Emissions	**0.2153**

Example Calculation

Example calculation for VOC emissions from ICR Reported dehydration units:

VOC Emissions (tpy) = AQP Generated GRI-GLYCalc Emissions Output x Number of 2020 ICR Reported Dehydration Units

Example:

24.2 tpy annual VOC emissions = 0.4399 tpy VOC x 50 reported dehydration units

Emissions

VOC and HAP emissions from 50 TEG Dehydration Units at small oil and gas sources on the Reservation are provided in Table 17.

Table 17: VOC and HAP Emissions from TEG Dehydration Units from small oil and gas sources [tons]

	Number of Dehydration Units	VOC	Total HAP	Benzene	Toluene	Ethylbenzene	Xylenes
Totals	50	19.4	8.7	1.0	3.4	0.5	3.6

D. Liquid Storage Tanks

Description of Equipment and Emissions Categories

The oil and gas industry utilize liquid storage tanks for the storage of produced water, condensate, oil, coolants, and lubricants. The primary emissions from liquid storage tanks are methane, VOC and HAPs. Emission categories include breathing and working losses, flash emissions, and tank loadout.

Breathing and Working Losses:

Breathing losses occur when vapor expansion generated during temperature fluctuations increases the vapor pressure within a tank and cause fugitive emissions to escape from the roof vent. Light colored tanks and tank heaters can help maintain more consistent tank temperatures and reduce breathing losses by reducing vapor pressure variations. Full tanks also produce lower breathing losses due to less space for vapors to expand and escape from roof vents. Working losses occur when liquids are pumped into and out of storage tanks. The displacement of vapors within the tank and the turbulence caused by the movement of the liquid create airborne vapors. Submerged fill tanks can be effective for reducing turbulence and the creation of airborne vapors.

Flash Emissions:

Flash emissions are emissions that occur when liquid dumped from the separator into the liquid storage tank goes from higher pressure to lower pressure, resulting in the entrained gas being released as a vapor from the liquid. The gas to liquid ratio, pressure and temperature of the liquids in the separator, and the temperature and pressure of the liquid storage tank influence the amount of flashing losses.

Tank Loadout Emissions:

Tank loadout emissions are vapor loss from transport tanks that occur during the transfer of liquids from a storage tank to a transport tank. Loadout emissions occur due to the generation of vapors in transport tanks during liquid loading, the transfer of vapors from the liquid storage tank to the transport tank, and the displacement of vapors trapped in transport tanks from previous loads during loading.

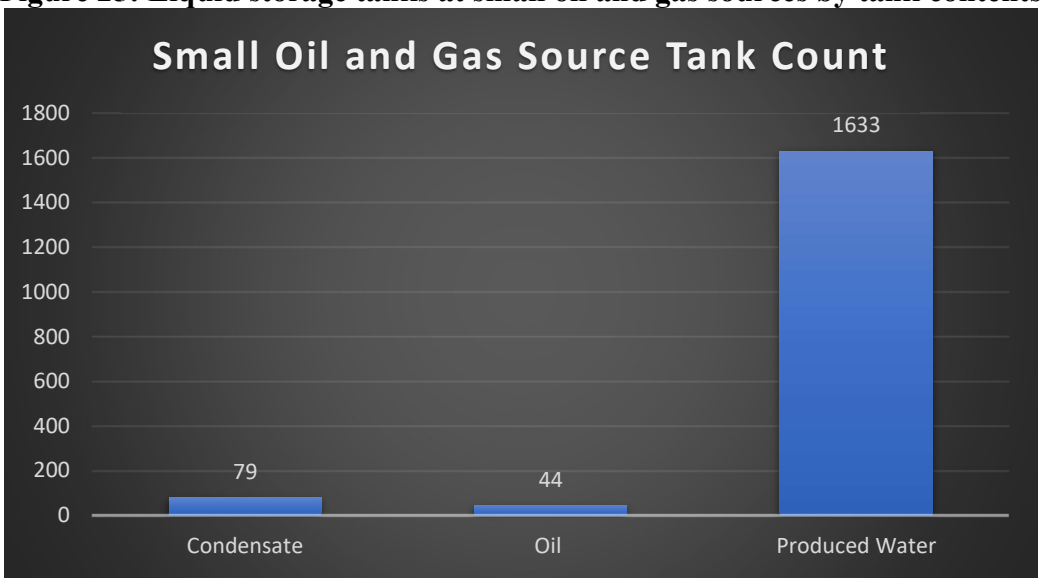
Data Collection

Tank Counts and Data for Calculating Breathing and Working Losses:

The ICR required each operator to provide the total number of produced water, condensate, and oil tanks located at their small oil and gas sources on the Reservation. Reported tank counts were based on tank capacity and contents.

A summary of tanks reported in the ICR, by tank contents, is displayed below in Figure 25.

Figure 25: Liquid storage tanks at small oil and gas sources by tank contents



The ICR also provided operators with the opportunity to override assumed data values for annual liquid throughput, Reid Vapor Pressure, and general tank characteristics with values more representative of their operations. Tank characteristics include roof type, color, condition, and presence of a tank heater. Development of liquid throughput values is discussed later in this section. Emissions from lubricant oil and glycol storage tanks were assumed to be negligible and no data was requested for these sources.

Methodology for Deriving Average Liquid Throughput Values:

The AQP developed two types of annual liquid throughput values, based on the availability of data in the COGCC database for sources in La Plata County, Colorado for CY 2020. If data were available from COGCC, the AQP used operator-specific throughput values and if the data were not available, the AQP developed assumed annual average liquid throughput values. The operator-specific annual average liquid throughput values were derived by dividing their total reported produced water and condensate/oil

production numbers by the total number of sources that reported production for CY 2020.

Assumed average annual liquid throughput values were developed for operators that reported active sources to the COGCC in 2020 but did not report production. The assumed annual throughput value for produced water was derived by dividing the total CY 2020 produced water production values reported to the COGCC database by the total number of reported sources. A combined condensate and oil assumed annual average tank throughput value was derived by dividing the total CY 2020 combined condensate and oil production value reported to the COGCC database by the number of small oil and gas sources that reported condensate or oil production. Not all companies reported condensate or oil production to COGCC, and four companies reported much larger condensate and oil production numbers than other companies producing condensate and oil. Companies that did not produce any condensate or oil and the few companies with large production numbers were dropped from the calculations to avoid skewed production numbers. Assumed annual average liquid throughput values for the produced water, oil, and condensate at small oil and gas sources on the Reservation are displayed below in Table 18.

Table 18: Assumed annual average liquid throughput values for produced water, oil, and condensate tanks at small oil and gas sources*

Number of Sources Operating in 2020	2,903
2020 Oil/Condensate Produced [bbl]	13,933
2020 Water Produced [bbl]	9,018,787
Average Oil/Condensate per source per year [bbl]	0.12
Average Water per source per year [bbl]	1,361

*Throughput numbers were derived from averaging production numbers from COGCC (2020). Production Data. Retrieved from http://cogcc.state.co.us/data2.html#/downloads.

Emission Calculation Methodology

Liquid storage tank emissions are calculated based on three separate emission event categories that occur during normal tank operation at atmospheric pressures, as described earlier in this section. The emissions categories include: breathing and working losses, flash emissions, and loadout emissions. Discussions are provided below the methodologies used to calculate emissions for each tank emissions category.

Breathing and Working Losses

Data Collection and Assumptions:

Emission totals for the Reservation were developed for each individual operator by running the EPA TANKS 4.09d Emissions Estimation Software (TANKS) model once for each tank size and production type category reported in the ICR and then multiplying

each modeled emissions total by the number of corresponding tanks reported.[17] Reported liquid throughput values were used when provided and assumed throughput values were used when data was not provided.

Emission Calculations:

Standing, and working losses were calculated using the TANKS model and reported or assumed input data values for liquid throughput, Reid vapor pressure, and tank characteristics. An equal distribution through all tanks was assumed by dividing the total production by the total number of tanks in a given category. Produced water was assumed to consist of a mixture of 99% water and 1% condensate. Condensate was assumed to have a Reid Vapor Pressure of 10 in the TANKS model. The default values for crude oil were used for oil tank calculations. The model was run for tanks operating at atmospheric pressure and the TANKS model meteorological conditions for Albuquerque, New Mexico. Emission estimates using this geographic location may be biased slightly higher, as average temperatures in Albuquerque are warmer than within the Reservation. All tanks were assumed to have a cone shaped roof, to be gray in color, and equipped with a tank heater.

Liquid Storage Tanks Flash Emissions

Data Collection and Assumptions:

The ICR requested flash gas liberation data from produced water, condensate, and oil, to aid in calculating flash emissions. No ICR submittals were returned with flash liberation data, as this type of sampling is not common practice on the Reservation.

In September 2016, the AQP contracted a third-party vendor to perform flash liberation sampling at well-site locations operated by two different companies on the Reservation. Sampling was performed on the separator at each well-site in order to obtain a pressurized sample. In total, seven produced water samples were obtained from coal-bed methane wells of the Fruitland Coal Formation on the east and west sides of the Reservation. Two produced water samples and one condensate sample were obtained from conventional natural gas wells of the Picture Cliffs Sandstone Formation in the south central portion of the Reservation.[18] Due to the very low oil production numbers reported to the COGCC database for La Plata County Colorado in CY2020 and the absence of viable sampling locations, the AQP elected to not obtain oil flash gas samples, but to use the condensate flash sampling results to estimate oil flash emissions

[17] U.S. EPA. (2006). TANKS 4.09d Emissions Estimation Software. Retrieved from https://www3.epa.gov/ttnchie1/software/tanks.

[18] Air Pollution Testing, Inc. (2016). Southern Ute Indian Tribe Flash Liberation Analyses.

Two additional condensate flash samples were provided by an operator that performed sampling in August 2016 from liquid knockout locations on a well-site gathering pipeline containing natural gas from conventional wells in the southern portion of the Reservation.

All sampling reports included an extended gas analysis, gas to water ratio, gas specific gravity, separator temperature and pressure, and ambient temperature and pressure.

Results from the six valid produced water samples were averaged to obtain assumed gas composition, gas to water ratio values, gas molecular weight, and gas component weight percent to be used in the development of emission factors for estimating storage tank flash emissions. The same methodology was applied for deriving average composition values from the three valid condensate samples.

Averaged extended gas analysis values for produced water and condensate are displayed below in Table 19 and Table 20, respectively. Averaged gas to water and gas to condensate values are displayed below in Table 21.

Table 19: Produced water flash gas analysis from small oil and gas sources on the Southern Ute Indian Reservation [Mol %]*

Flash Gas Component	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Average
Hydrogen Sulfide	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Nitrogen	0.0373%	0.0000%	1.0883%	1.0464%	2.6862%	0.5921%	0.9084%
Carbon Dioxide	72.3236%	68.4996%	36.5680%	29.7757%	5.8668%	16.3515%	38.2309%
Methane	26.6076%	31.0289%	62.2021%	67.0612%	91.4075%	76.3697%	59.1128%
Ethane	0.3200%	0.0271%	0.1155%	0.0138%	0.0119%	4.0640%	0.7587%
Propane	0.0359%	0.0231%	0.0124%	0.037%	0.0079%	1.0078%	0.1874%
Isobutane	0.0036%	0.0035%	0.0012%	0.0049%	0.0007%	0.1582%	0.0287%
N-Butane	0.0100%	0.0160%	0.0015%	0.0163%	0.0029%	0.1689%	0.0359%
2,2 Dimethylpropane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Isopentane	0.0028%	0.0037%	0.0003%	0.0071%	0.0005%	0.1027%	0.0195%
N-Pentane	0.0039%	0.0078%	0.0005%	0.0117%	0.0012%	0.0612%	0.0144%
2,2 Dimethylbutane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Cyclopentane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0108%	0.0018%
2,3 Dimethylbutane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2 Methylpentane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3 Methylpentane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-Hexane	0.4360%	0.1881%	0.0005%	1.8678%	0.0035%	0.2114%	0.4512%
Methylcyclopentane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Benzene	0.0085%	0.0000%	0.0000%	0.0227%	0.0000%	0.1056%	0.0228%
Cyclohexane	0.0084%	0.0000%	0.0000%	0.0418%	0.0021%	0.0481%	0.0167%
2-Methylhexane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3-Methylhexane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2,2,4 Trimethylpentane	0.0000%	0.0000%	0.0000%	0.0000%	0.0003%	0.0088%	0.0015%
Other C7's	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-Heptane	0.0000%	0.0000%	0.0006%	0.0000%	0.0026%	0.2092%	0.0354%
Methylcyclohexane	0.0037%	0.0000%	0.0000%	0.0081%	0.0029%	0.0865%	0.0169%
Toluene	0.0108%	0.0000%	0.0000%	0.0514%	0.0016%	0.1397%	0.0339%
Other C'8s	0.1872%	0.0000%	0.0091%	0.0196%	0.0011%	0.2745%	0.0819%
N-Octane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Ethylbenzene	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0049%	0.0008%
M&P Xylenes	0.0008%	0.0000%	0.0000%	0.0141%	0.0000%	0.0242%	0.0065%
O-Xylene	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Other C9's	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-Nonane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Other C10's	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-Decane	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Undecanes(11)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Totals:	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Total VOC:	**0.7116%**	**0.2422%**	**0.0261%**	**2.1029%**	**0.0273%**	**2.6225%**	**0.9554%**
Total HAP:	**0.4561%**	**0.1881%**	**0.0005%**	**1.9560%**	**0.0054%**	**0.4946%**	**0.5168%**

*Air Pollution Testing, Inc. (2016, September). Southern Ute Indian Reservation Flash Liberation Analyses.

Table 20: Condensate flash gas analysis from small oil and gas sources on the Southern Ute Indian Reservation [Mol %]*

Flash Gas Component	Sample 1	Sample 2	Sample 3	Average
Hydrogen Sulfide	0.000%	0.000%	0.0000%	0.000%

Nitrogen	6.633%	5.170%	0.5871%	4.130%
Carbon Dioxide	3.053%	2.564%	2.8208%	2.813%
Methane	62.466%	62.678%	50.2222%	58.455%
Ethane	14.918%	16.162%	20.4293%	17.170%
Propane	6.279%	7.028%	12.0540%	8.454%
Isobutane	1.371%	1.353%	3.2488%	1.991%
N-Butane	1.738%	1.840%	3.6206%	2.400%
2,2 Dimethylpropane	0.000%	0.000%	0.0000%	0.000%
Isopentane	0.794%	0.769%	1.7594%	1.107%
N-Pentane	0.551%	0.560%	1.0198%	0.710%
2,2 Dimethylbutane	0.000%	0.000%	0.0000%	0.000%
Cyclopentane	0.000%	0.000%	0.1844%	0.061%
2,3 Dimethylbutane	0.000%	0.000%	0.0000%	0.000%
2 Methylpentane	0.000%	0.000%	0.0000%	0.000%
3 Methylpentane	0.000%	0.000%	0.0000%	0.000%
N-Hexane	0.869%	0.748%	1.4232%	1.013%
Methylcyclopentane	0.000%	0.000%	0.0000%	0.000%
Benzene	0.105%	0.076%	0.1128%	0.098%
Cyclohexane	0.000%	0.000%	0.0000%	0.000%
2-Methylhexane	0.000%	0.000%	0.0000%	0.000%
3-Methylhexane	0.000%	0.000%	0.0000%	0.000%
2,2,4 Trimethylpentane	0.003%	0.003%	0.0291%	0.012%
Other C7's	0.000%	0.000%	0.0000%	0.000%
N-Heptane	0.557%	0.461%	0.7371%	0.585%
Methylcyclohexane	0.000%	0.000%	0.2793%	0.093%
Toluene	0.166%	0.126%	0.1768%	0.156%
Other C'8s	0.000%	0.000%	0.8700%	0.290%
N-Octane	0.304%	0.247%	0.0000%	0.184%
Ethylbenzene	0.008%	0.007%	0.0076%	0.008%
M&P Xylenes	0.071%	0.074%	0.1086%	0.085%
O-Xylene	0.000%	0.000%	0.0000%	0.000%
Other C9's	0.000%	0.000%	0.0000%	0.000%
N-Nonane	0.088%	0.088%	0.0000%	0.059%
Other C10's	0.000%	0.000%	0.0000%	0.000%
N-Decane	0.027%	0.048%	0.0000%	0.025%
Undecanes(11)	0.000%	0.000%	0.0000%	0.000%
Totals:	**100%**	**100%**	**100%**	**100%**
Total VOC:	**12.9310%**	**13.4280%**	**25.6315%**	**17.3302%**
Total HAP:	**1.2220%**	**1.0340%**	**1.8581%**	**1.3714%**

*Air Pollution Testing, Inc. (2016, September). Southern Ute Indian Reservation Flash Liberation Analyses.

Table 21: Average gas to water and gas to condensate ratios for small oil and gas sources*

Gas/Water [scf/bbl]	Gas/Condensate [scf/bbl]
3.3	16.5

*Air Pollution Testing, Inc. (2016, September). Southern Ute Indian Reservation Flash Liberation Analyses.

Flash Emission Calculation Methodology:

Flash emission factors in pounds per barrel (lb/bbl) were developed for VOC, BTEX, methane, and carbon dioxide. The measured gas oil/gas water ratio (scf/bbl) was divided by the ideal gas law conversion factor (scf/lb-mol) and then multiplied by the molecular weight of the flash gas (lb/lb-mol) and then multiplied by the weight percent of each specific component to derive the emission factors. The total emissions were calculated by multiplying the emission factors for each component by the total reported production in barrels. Tank throughput values in barrels per day were either reported values or the assumed values developed by AQP, as described previously in this section. Flash emission totals for the Reservation were developed for each individual operator using either reported or assumed liquid throughput values.

Example Emission Factor Development for Flash Emissions:

$$Emission\ Factor\ (lb/bbl) = GOR/R*MW*Wt\%$$

Where:

GOR = measured gas oil/gas water ratio (scf/bbl)
R = ideal gas law conversion factor (scf/lb-mol)
MW = molecular weight of flash gas (lb/lb-mol)
Wt% = weight percent of desired component in flash gas

Example Emission Calculation:

$$Emissions\ (ton/year) = EF*P/2000$$

Where:

EF = emission factor (lb/bbl)
P = annual production (bbl/year)
2000 = conversion factor (lb/ton)

Liquid Storage Tank Loadout Emissions

Data Collection and Assumptions:

Tank loadout emissions were calculated by conservatively assuming that all liquid storage tanks are unloaded manually by truck, and not sent through pipeline. Emission factors and emission calculations were derived from Section 5.2 of EPA AP-42 for Transportation and Marketing of Petroleum Liquids. Loading was assumed to be submerged fill and the saturation emission factor for submerged dedicated normal service was selected for calculating loading losses. Truck tank capacity was assumed to be 100 bbl per loadout event and reported or assumed liquid production numbers were used for calculating the number or loadout events per year. Each loadout event was assumed to be one-hour in duration and the assumed annual hours of unloading operations for each operator were directly correlated to the reported or assumed annual liquid production. Molecular weight and true vapor pressure values were derived from TANKS model runs for produced water and condensate.

Example Tank Loadout Emissions Calculation Methodology:

Tank loadout emissions are calculated using two separate calculations. The first equation is used to estimate the total molecular weight of loading emissions losses and a second equation is used to estimate the total emission rate on a pollutant basis. Both calculations are displayed below:

Loading Losses Calculation:

$$L = 12.46 \times (S) \times (P) \times ((MW)/T) \times (1\text{-}eff)$$

Where:

L=Loading Losses (lb/1000 gallons)
S = Saturation Factor
P = True Vapor Pressure (Pva @ T)
MW = Molecular Weight (lb/lb-mol)
T = Temperature
E = Control Efficiency of Loading

Total Emission Rate Calculation:

$$Tons\ Per\ Year = L*Annual\ Throughput/2000*Wt\%$$

Where:

L = Loading Losses (lb/1000 gallons)
Annual Throughput = annual throughput (1000 gallons)
2000 = conversion factor (lb/ton)
Wt% = Component Weight Percentage from Flash Gas Analysis

Liquid Storage Tank GHG Emissions

Tank Flash Greenhouse Gas Emissions:

Flash greenhouse gas (GHG) emissions for storage tanks were calculated using the measured data from the flash liberation sampling completed in 2016 from well-sites on the Reservation. Emission factors for Methane and Carbon Dioxide were developed as cited in the *Flash Emission Calculation Methodology* section of this report. These emission factors were multiplied by the total production and divided by a conversion factor to provide an output in tons per year. This was then multiplied by a conversion factor to convert to metric tonnes and then multiplied by the global warming potential of each component, found in Sixth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) Table 7.15, to provide an output total in metric tonnes of carbon dioxide equivalent.

Example Calculation for Tank Flash GHG Emission:

$$CH4\ (CO2e) = (EF*P/CF1)*CF2*GWP$$

Where:

EF = emission factor (lb/bbl)
P = annual production (bbl/year)
CF1 = conversion factor (2000lb/ton)
CF2 = conversion factor (0.907185 metric tonnes/ton)
GWP = global warming potential (29.8 for Methane, 273 for N_2O)

Tank Loadout GHG Emissions

GHG emissions from tank loadout were calculated using the same methodology found in the *Liquid Storage Tank Loadout Emissions* section of this report. Once the loadout emissions, in tons per year, are determined for a GHG, it is multiplied by a conversion factor to convert it to metric tonnes. This metric tonnes number is then multiplied by the global warming potential of the individual component to provide an output in metric tonnes of carbon dioxide equivalent.

Example Tank Loadout GHG Calculations:

$$CO2e = tpy*CF*GWP$$

Where:

CO2e = carbon dioxide equivalent (metric tonnes)
tpy = emissions (tons per year)
CF = conversion factor (0.907185 metric tonnes/ton)
GWP = global warming potential of individual pollutant

Total Liquid Storage Tank Emissions

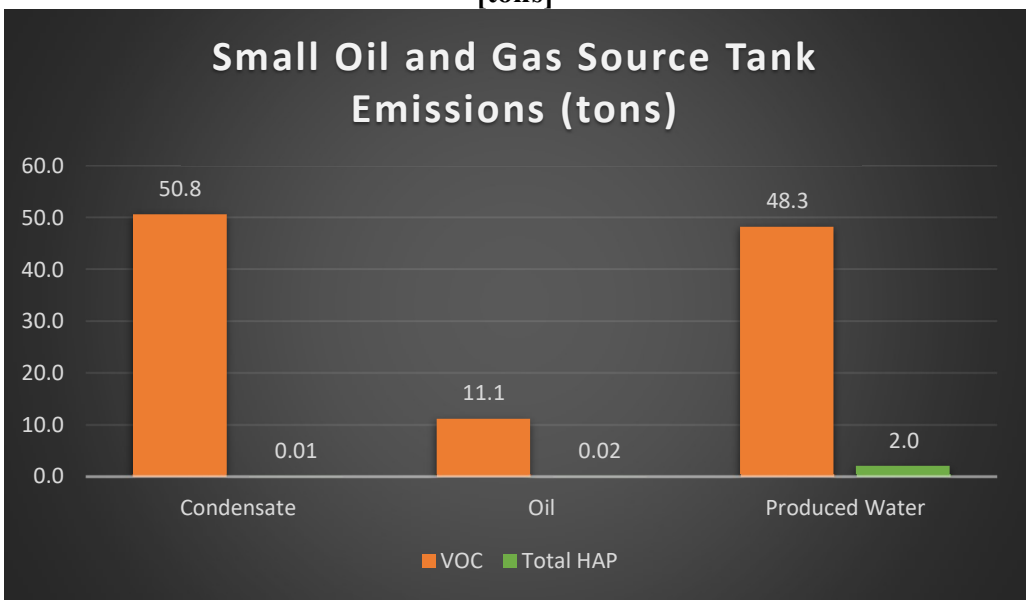
Total liquid storage tank emissions at small oil and gas sources from working and breathing losses, flash emissions, tank loadout, and GHG emissions on the Reservation are displayed in below in Table 22 and Figure 26. Emissions are displayed by tank contents.

Table 22: VOC, HAP, and GHG Emissions from liquid storage tanks at small oil and gas sources [tons]*

Tank Contents	Tank Count	VOC	Total HAP	GHG
Condensate	79	50.8	0.01	5.3
Oil	44	11.1	0.02	14.8
Produced Water	1633	48.3	2.0	11,477.4
Totals	**1756**	**110.2**	**2.1**	**11,497.5**

*GHG emissions reported in metric tonnes

Figure 26: VOC and HAP emissions from liquid storage tanks at small oil and gas sources [tons]



E. External Combustion Sources

Description of Sources

Natural gas-fired external combustion sources are widely used by the natural gas industry as tank heaters, heated separators, reboilers, and boilers.

Data Collection

The ICR required each operator to report the total number of heaters and boilers operated by their company on the Reservation. Heater and boiler counts were reported according to heat rate range in MMBTU/hr. Operators were also given the option to report average heater and boiler operating hours to override the AQP's assumed operating hours. A description of the AQP's assumed values is included in the emission calculation discussion.

Assumptions

If no hours of operation were reported in the ICR, AQP assumed heaters to operate 24 hours per day for half of the year (183 days per year) which equates to 4,392 hours per year. Boilers were assumed to operate for 24 hours per day, 365 days a year, which equates to 8,760 hours per year.

Emission Calculation Methodology

Criteria pollutant and HAP emissions for external combustion sources were calculated using the emission factors from EPA AP-42 Chapter 1.4 for uncontrolled natural gas-fired external combustion sources, the maximum heat rating from each heat rating category reported in the ICR, a default natural gas heating value of 1,026 Btu/scf and assumed or reported operating hours.

The AQP used the default natural gas heating value of 1,026 Btu/scf from 40 CFR Part 98 to convert the EPA emission factors from lbs/MMscf to lbs/MMBtu.

GHG emissions were calculated using the Tier 1 calculation methodology, the natural gas emission factors from Tables C-1 and C-2 of 40 CFR Part 98 and assumed or reported operating hours.

Example Calculations

Criteria and HAP Example Calculations:

$$lb/hr = (EF/HV) \times (HR)$$

Where:

EF = Emission Factor (lb/MMscf)
HV = Default Heat Value of Natural Gas fuel (Btu/scf)
HR = Heat Rate of Boiler/Heater (MMBtu/hr)

Example NOx lb/hr calculation for 0.5 MMBtu/hr natural gas-fired boiler/heater:

lb/hr = (100/1,026) x 0.5 = 0.05

tpy = (lb/hr) x OH/2000

Where:

(lb/hr) = Emission Rate
OH = Annual Operating Hours
2000 = Pounds per ton

Example NOx tpy calculation for 0.5 MMBtu/hr natural gas-fired boiler/heater operating 4392 hours per year:

tpy = (0.05) x 4392/2000= 0.1098

GHG Example Calculation:

GHG Calculation Methodology:

= EF x HR x CF x GWP

Where:

EF = fuel specific default emission factor, from tables C-1 and C-2 of Part 98 (kg/MMBtu)
HR = heat rate (MMBtu/hr)
CF = conversion factor (lb/kg)
GWP = global warming potential

Emissions

Criteria pollutant, HAP, and GHG emissions from external combustion sources located at small oil and gas sources on the Reservation for calendar year 2020 are displayed below in Table 23. Emissions are displayed by unit count and heat rating in MMBtu/hr.

Table 23: Criteria pollutant, HAP, and GHG emissions from heaters and boilers at small oil and gas sources [tons]*

Equipment Type and Heat Rating	Unit Count	NOx	VOC	SO_2	PM	CO	HAP	GHG (CO_2e)
Heaters								
0.25 MMBtu/hr	1798	95.8	4.9	0.6	7.8	80.5	1.7	104,417.2
0.5 MMBtu/hr	328	35.0	1.9	0.2	2.9	29.4	0.6	38,162.0
1.0 MMBtu/hr	1001	214.2	11.8	1.3	16.3	180.0	1.5	233,523.4
100 MMBtu/hr	9	92.6	10.6	1.2	14.6	161.8	3.6	209,961.1
Heaters Total	3136	537.7	29.2	3.2	41.6	451.7	7.4	586,063.8
Boilers								
0.25 MMBtu/hr	6	0.6	0.0	0.0	0.1	0.5	0.0	698.0
Boilers Total	6	0.6	0.0	0.0	0.1	0.5	0.0	698.0

Total	**3142**	**538.3**	**29.3**	**3.2**	**41.7**	**452.2**	**7.4**	**586,761.7**

*GHG reported in metric tonnes.

F. Equipment Leaks and Fugitive Emissions

Description of Sources

Natural gas leaks from components commonly used in the natural gas industry result in emissions of methane, CO_2, VOC, and HAP. Components include: valves, pumps, pressure relief valves, connectors, flanges, and, open-ended lines. These components are ancillary equipment to many larger equipment source types including: headers, separators, heaters, filters, engines, compressors, dehydration units, and storage tanks.

Data Collection

The ICR provided operators with the option to report average fugitive component counts for single and co-located well-sites. In the absence of ICR provided component counts, the AQP relied on assumed component counts, as detailed below.

Assumptions

Fugitive component counts were assumed based on component counts for natural gas production contained in the Canadian Association of Petroleum Producers (CAPP) document titled *Guide to Calculating Greenhouse Gas Emissions*.[19] Component counts for single and co-located well-site locations are displayed below in Table 24.

Table 24: Assumed fugitive emission component counts at single and co-located natural gas well-sites

Component Type-Service	Component count for a Single well	Component count for Two co-located wells	Component count for Three Co-located wells	Component count for Four Co-located wells
Valves-Gas/Vapor	16	32	48	64
Connectors-Gas/Vapor	60	120	180	240
Open-Ended Lines-Gas/Vapor	3	6	9	12

Emission Calculation Methodology

GHG, VOC, and HAP Emission Calculations:

GHG, VOC, and HAP emissions from equipment leaks and fugitive emissions were calculated using the average emission factor approach and the gas/vapor total organic compound (TOC) emission factors for oil and gas production from Table 2-4 of EPA's

[19] Canadian Association of Petroleum Producers. (2003). *Guide to Calculating Greenhouse Gas Emissions.* Retrieved from http://www.capp.ca/publications-and-statistics/publications/241974.

OAQPS document titled *Protocol for Equipment Leak Emission Estimates.* The TOC emission factor for gas/vapor was chosen as the most representative of production on the Reservation in CY2020 and is the most conservative emission factor available. TOC emissions were calculated by multiplying the gas/vapor emission factor by component counts calculated using the *CAPP* generic fugitive component count and the number of sources entered in the ICR. Each source was assumed to operate for 8,760 hours annually. GHG, VOC, and HAP emissions were then derived by multiplying the TOC emissions by the GHG, VOC, and HAP molecular weight fraction percentages of an assumed extended natural gas analysis for the Reservation. If component counts were provided by operators in the ICR, emissions for their company's productions were calculated using their reported counts in place of the CAPP component counts.

Example Calculations

GHG, *VOC, and HAP Emission Calculation Methodology:*

GHG, VOC, or HAP Emissions = EPA OAQPS Average Emission Factor for Gas Valves x CAPP Generic Valve Count x Annual Operating Hours x (Ton/2000lb0 x weight percent (GHG, VOC, or HAP) = tpy GHG, VOC, or HAP emissions

Valves VOC Emissions (tpy) = (0.00992 lb/hr/valve) x 1000 valves x (8760 hr/yr) x (Ton/2000 lb) x (1.51%) = 0.66 tons/year

Emissions

Volatile organic compound, HAP, and GHG emissions from equipment leak and fugitive emission sources located at small oil and gas sources on the Reservation for calendar year 2020 are displayed below in Table 25.

Table 25: Emissions of VOC, HAP, and GHG from equipment leaks and fugitive emission sources at small oil and gas sources [tons]*

	VOC	Total HAP	GHG
Fugitives	172.2	0.4	298,443.7

*GHG reported in metric tonnes.

G. Natural Gas Driven Pneumatic Devices

Description of Sources

Natural gas-driven pneumatic controllers and pumps are used in the oil and natural gas industry for maintaining liquid levels, pressures, pressure differentials, and temperature. Many devices are designed to leak, or "bleed", natural gas and in doing so emit natural gas containing methane, CO_2, VOC, and HAP. Pneumatic devices are classified as high or

low continuous bleed controllers, intermittent bleed controllers, or zero bleed controllers.

Data Collection

The AQP assigned an assumed value for the average number of pneumatic devices located at a single wellsite from the 2014 Environmental Science and Technology report titled *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States*.[20] The assumed pneumatic device count value was provided in the ICR and operators were provided the opportunity to override the assumed value with values more representative of their operations.

Emission Calculation Methodology

Pneumatic device emissions were calculated by applying the generic natural gas emission factors found in EPA's April 2014 Report for Oil and Natural Gas Sector Pneumatic Devices to the AQP's assumed average device count or average device counts reported in the ICR.

Example Emission Calculation:

$$lb/hr = Count \times Bleed\ Rate \times R \times MW \times Y$$

Where:

Count = total number of devices
Bleed Rate = bleed rate from device (scf/hr/device)
R = Universal gas constant (lb-mol/379.4scf)
MW = molecular weight of the component (lb/lb-mol)
Y = volume fraction of component in the vented gas

Example for Methane:

$$lb/hr = 2695 \times 5.5 \times 1/379.4 \times 16.01 \times 92\% = 575.4\ lb/hr$$

$$tpy = \quad lb/hr \times OH/2000$$

Where:
lb/hr = emission rate in pounds per hour
OH = annual operating hours

[20] Allen, D. (2014). Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers. *Environmental Science & Technology, 49*, 633-640. Retrieved from http://pubs.acs.org/doi/pdf/10.1021/es5040156.

2000 = pounds per ton

tpy methane = 575.4 x 8760/2000 = 2520.3 tpy

Emissions

VOC, HAP, and GHG emissions from natural gas driven pneumatic devices on the Reservation during 2020 are displayed below in Table 26.

Table 26: VOC, HAP, and GHG emissions from natural gas driven pneumatic devices at small oil and gas sources [tons]*

	VOC	Total HAP	GHG
Pneumatics	146.4	10.2	217,529.5

*GHG reported in metric tonnes.

H. Natural Gas Blowdowns

Description of Sources

Natural gas blowdowns are intentional and unintentional gas releases during maintenance, routine operations, and emergencies. Blowdowns occur from gas compressors, compressor startups, gas wellbores, vessels, pipelines, and various equipment.

Data Collection

The ICR requested emissions resultant from maintenance and emergency natural gas blowdowns from compressors. Due to the burden of capturing actual emissions for each blown down event at a large number of small oil and gas sources, emissions from such events are based on assumptions on the amount of gas released, the AQP's assumed extended gas analysis, and an assumed number of events anticipated during a calendar year. The ICR provided operators with the opportunity to override the AQP's assumed values with values more representative of their operations.

Assumptions

The AQP developed assumed values for the number and time duration of annual compressor blowdowns that occur per year and the volume of natural gas vented per event. Assumed values were based on the 2015 Colorado Air Resources Management Modeling Study (CARMMS)[21]. The values assumed for 2020 are displayed below in Table 27.

[21] ENVIRON International Corp.; Carter Lake Consulting; Environmental Management and Planning Solutions. (2015). *Colorado Air Resources Management Modeling Study.* Retrieved from

Table 27: Assumed values for annual natural gas compressor blowdown events occurring at small oil and gas sources in 2017

Compressors	
Annual compressor blowdowns per compressor	2
Estimated amount of gas lost per blowdown [Mscf/event]	10

Emissions Calculation Methodology

Emissions from natural gas blowdowns were calculated using either the AQP's assumed extended gas analysis or reported natural gas analysis, and assumed or reported event frequencies, duration, and gas loss values.

Example Calculations:

tpy = Total vented x Ideal Gas Density/2000

Where:

Total vented = total volume of gas vented (for specific component) (scf/yr)

= (volume vented per blowdown (Mscf/event) x frequency (events/yr) x 1000scf/Mscf) x %vol of component

*Ideal Gas Density (lb/scf) = MW/(R*T)*
MW = molecular weight of the component
R = universal gas constant (0.730235 scf.atm/°R.lb-mol)
T = temperature (60 °F converted to 519.67 °R)
2000 = pounds per ton

Emissions

Emissions from natural gas blowdown activities occurring on the Reservation during 2020 are displayed below in Table 28.

Table 28: VOC, HAP, and GHG emissions from natural gas blowdowns at small oil and gas sources [tons]*

Pollutant	VOC	Total HAP	GHG
Blowdowns	0.1	0.0	182.2

*GHG reported in metric tonnes.

https://www.blm.gov/sites/blm.gov/files/documents/files/program_natural%20resources_soil%20air%20water_airco_quicklins_CARMMS2.0.pdf.

I. Well Completion and Re-completion Venting

Description of Sources

Well completions and recompletions, when not employing closed vent system techniques, also known as "green completions", release natural gas during the "flow back" stage of the process. Flow back is the stage in which drilling fluid and hydrocarbon reservoir fluids return to the surface prior to well production. Green completion techniques capture flow back materials, including natural gas.

Data Collection

The number of well completions that occurred in calendar year 2020 were obtained from the COGCC database. Zero well completions occurred on the Reservation in calendar year 2020. No data were available for well recompletions in the COGCC database and an assumed recompletion value of 1% of all operating wells per year was obtained from the 2015 CARMMS.

The ICR also provided the opportunity for operators to report the number of well completion and recompletion events that occurred in calendar year 2020, including natural gas lost per event, and completion by type (conventional or green completion).

Assumptions

Fifty percent of all well completions and recompletions were assumed to utilize green completion technology with no natural gas vented to atmosphere. Conventional well completions and recompletions were assumed to vent 1,000 Mscf of natural gas per event. These assumptions were derived from the 2015 CARMMS.

For well recompletions, the assumed well recompletion value of 1% of all operating wells per year was obtained from the CARMMS study and assumed to be accurate and representative of operations on the Reservation.

All completion and recompletion activities were assumed to be either conventional or green completions, based on information provided by two large natural gas operators on the Reservation. Therefore, the AQP did not estimate emissions from flaring events that may occur during well completion or re-completion activities. Assumed well completion and recompletion values for 2020 are displayed below in Table 29.

Table 29: Assumed values for well completion and recompletion activities at small oil and gas sources*

Completion Type	Conventional	Green Technology
Percent of completions by type:	50%	50%

Estimated amount of gas vented to atmosphere per event [Mscf/event]:	1000	0
Estimated amount of gas controlled via closed loop system per event [Mscf/event]:	0	1000

*Assumed values are based on the 2015 CARMMS.

Emission Calculation Methodology

Emissions from well completion and recompletions were calculated using an assumed extended gas analysis and reported or assumed event frequencies and gas loss values. Emissions from drilling engines that are employed during well completion and re-completion activities were not calculated.

Emissions

Emissions from well completion and recompletion venting on the Reservation in calendar year 2020 are displayed below in Table 30.

Table 30: VOC, HAP, and GHG emissions from well recompletion activities at small oil and gas sources [tons]*

	VOC	Total HAP	GHG
Recompletions	42.9	0.1	27,232.2

*GHG reported in metric tonnes.

VOC, HAP, and GHG emissions from Fugitives, Blowdowns, Recompletions, and Pneumatics are displayed below in Figure 27 and Figure 28.

Figure 27: VOC and HAP emissions from Fugitives, Blowdowns, Recompletions, and Pneumatics [tons]

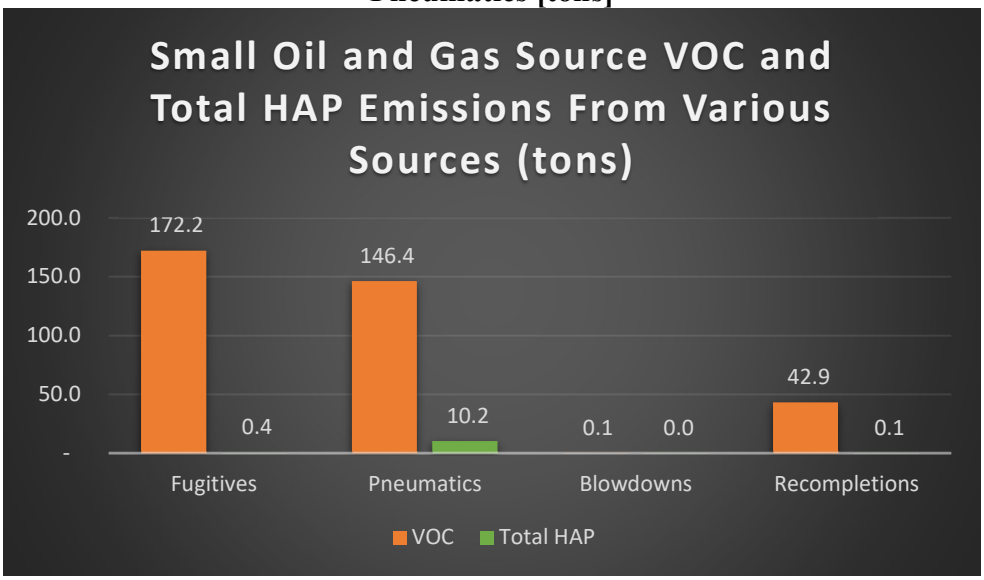
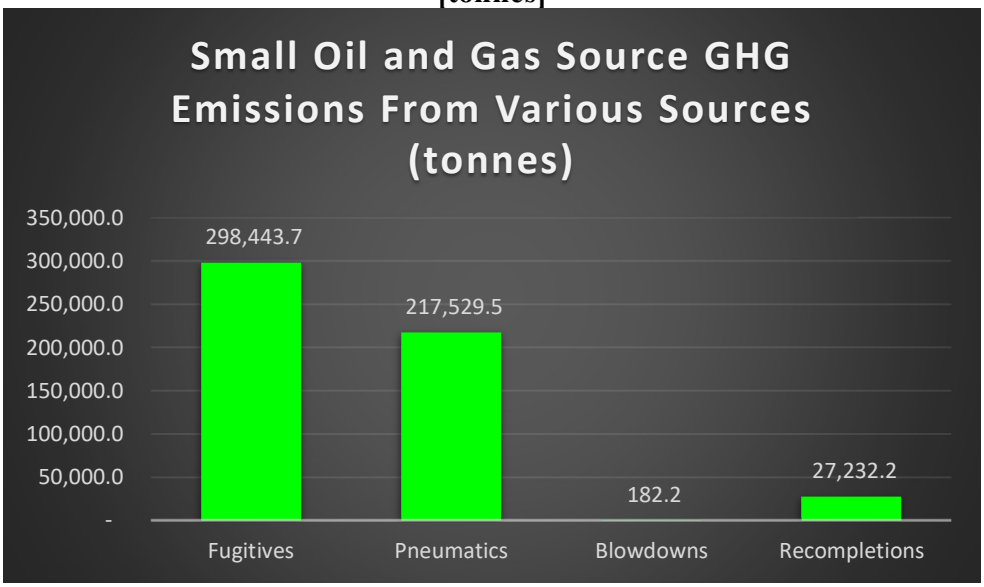


Figure 28: GHG emissions from Fugitives, Blowdowns, Recompletions, and Pneumatics [tonnes]



J. Typical Well-Site Configuration

Description

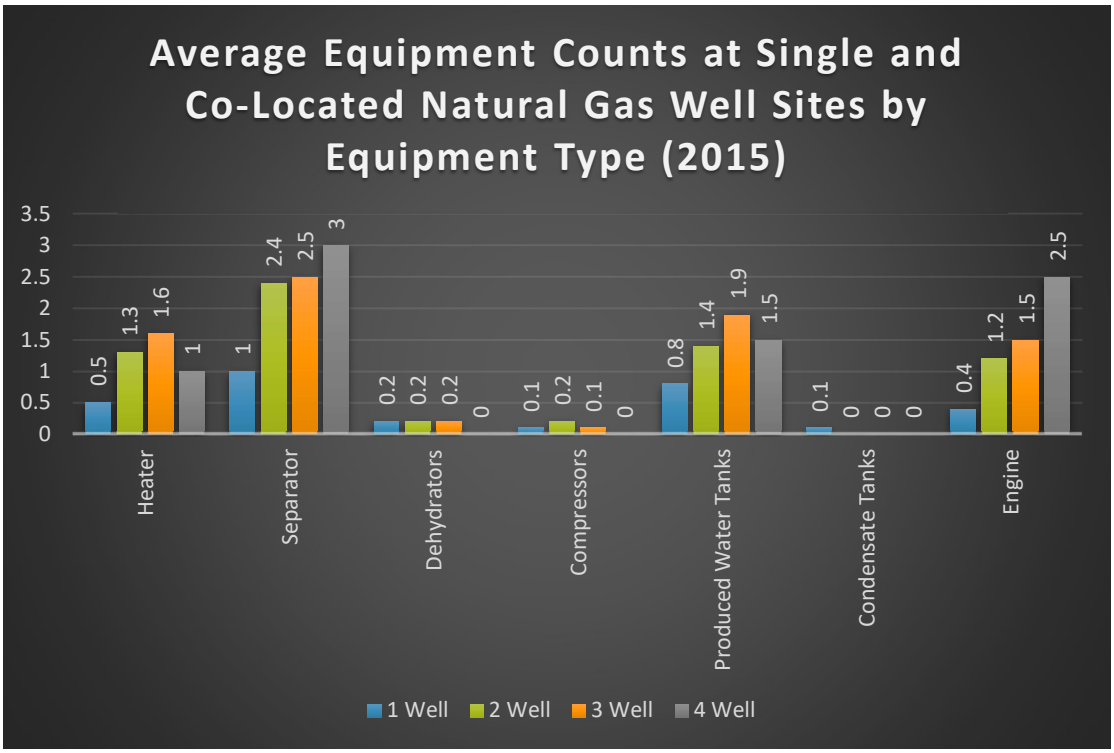
The AQP compiled equipment count information collected in the previous comprehensive emission inventory ICRs in CY 2015 to prepare average equipment type counts based on the number of natural gas wells located on a single well-pad. This information can be used to gain a better understanding of typical well-site configurations on the Reservation and to assist with estimating emissions from any proposed natural gas development schedules.

Average equipment counts at small oil and gas sources on the Reservation are displayed below in Table 31 and Figure 29.

Table 31: Average equipment counts at single and co-located well-sites at small oil and gas sources

Number of Wells per Pad	Heater	Separator	Dehydrators	Compressors	Produced Water Tanks	Condensate Tanks	Engine
1	0.5	1.0	0.2	0.1	0.8	0.1	0.4
2	1.3	2.4	0.2	0.2	1.4	0.0	1.2
3	1.6	2.5	0.2	0.1	1.9	0.0	1.5
4	1.0	3.0	0.0	0.0	1.5	0.0	2.5

Figure 29: Average equipment counts at small oil and gas sources by equipment type



2. Fruitland Formation Outcrop Natural Gas Seeps

Description of Sources

Naturally occurring methane and CO_2 seepage from outcrops of the Cretaceous Fruitland Formation (Fruitland Outcrop) contribute a significant quantity of the GHG emissions on the Reservation.

Data Collection

The data used to quantify emissions from the Fruitland Outcrop were provided to the AQP from the SUIT Department of Energy (SUIT DOE). SUIT DOE has collected outcrop seepage data on an annual basis since 2007 using an independent contractor between 2007 and 2020. The goal of the study is identification, mapping, and quantification of methane seeps on the Fruitland Outcrop. A backpack mounted, hand-held gas flux meter manufactured by WEST Systems is used to measure methane and CO_2 soil gas flux concentrations in moles per meters squared per day [mol/m² day] at thirty-five seep areas, totaling 51,667,675 square feet (1.9 miles) of ground. The flux concentrations were then used by the contractor to calculate volumetric methane and CO_2 concentrations for 2020 in MCFD.

Emission Calculation Methodology

The AQP calculated ton per year emission rates for methane and CO_2 by converting the volumetric methane and CO_2 flux concentrations from MSCF to SCFD and then dividing the flux concentrations by the ideal gas law constant and multiplying the constants by the molecular weight of each gas. GHG emissions in CO_2 equivalence (CO_2e) were calculated by multiplying methane emissions by the IPCC's global warming potential factor of 29.8 for methane.

Example Calculations

Calculation to Convert Flux Rate in SCFD to lb/day

*lb/day = Flux/Ideal Gas Law Conversion Factor*molar mass*

Where:

Flux = Volumetric gas flux in SCFD
Ideal Gas Law Conversion Factor = 379.3 SCF/mol
*Molar Mass = g*Mol^{-1} (CH4 = 16.04; CO2 = 44.01)*

*lb/day Methane = 27,574,000/379.3*16.04 = 1,166,061 lb/day Methane*

Calculation to convert lb/day to tpy:

*tpy = lb/day/2000(lb/ton)*365 (days/year)*

Emissions

Emission calculations for methane, CO_2, and total GHG in CO_2e are displayed below in Table 32:

Table 32: Emissions of methane, CO_2, and total GHG in CO_2 Equivalent [tonnes]

Methane	5,753,025.33
CO_2	170,315.82
Total GHG (CO_2e)	5,923,341.15

3. Gas Stations

Description of Sources

There are five road and one marina gasoline service station that operated on the Reservation during calendar year 2020.

Data Collection

2020 gasoline throughput values were provided to the AQP by representatives of each gas station, and the total throughput is displayed below in Table 33.

Table 33: Annual gasoline throughput at gasoline stations located on the Southern Ute Indian Reservation [gal/yr]*

Total Gasoline Throughput:	1,650,141.75

Assumptions

AQP assumed that gasoline throughput values reported by gas station representatives are valid.

Due to the absence of emission factors for diesel fuel dispensing in EPA AP-42 Section 5.22, the AQP assumed emissions from diesel fuel dispensing to be negligible and did not calculate emissions for this activity. EPA AP-42 Section 5.2.2, also assumes a negligible methane content from gasoline evaporative emissions; therefore, AQP did not calculate GHG emissions for gas stations.

Emission Calculation Methodology

Gas station emissions were calculated using the Tribal Emissions Inventory Software Solutions (TEISS) emissions calculator for gasoline service stations.[22] The calculator employs emission factors from EPA AP-42 Section 5.2.2. Total reported fuel throughputs were input into the TEISS emissions calculator for two stages of gasoline service station emissions. Stage 1 includes underground tank filling and submerged filling. Stage 2 includes underground tank breathing and emptying, vehicle refueling displacement losses (uncontrolled), and spillage.

Emissions

Total VOC emissions from gas stations on the Reservation during 2020 are displayed below in Table 34.

Table 34: VOC emissions from gasoline dispensing stations [tons]

Pollutant	Emissions
VOC	16.83

4. Aviation Gasoline

[22] Institute for Tribal Environmental Professionals. (2021). Tribal Emissions Inventory Software Solution Version 3.6. Retrieved from http://www7.nau.edu/itep/main/air/air_aqt_teiss.

Description of Sources

Emission estimates for aviation gasoline and the amount of lead in the leaded gasoline for counties were last developed by EPA for calendar year 2014. Lead is an additive in aviation gasoline used for piston-engine aircrafts (either general aviation or air taxi) to increase the fuel octane and prevent valve seat decline, which is a safety concern.

Data Collection

Data was obtained from the EPA NEI for calendar year 2017. EPA's data collection methodology is described in EPA's 2008 Technical Support Document titled *Lead Emissions from the Use of Leaded Aviation Gasoline in the United States*.[23]

Assumptions

The AQP assumed EPA's calendar year 2017 EPA's aviation gasoline emission estimates for La Plata County and Animas Air Parks would be the most representative emission estimates available for calendar year 2020.

Emissions

VOC and HAP emissions from aviation gasoline usage on the Reservation in 2020 is displayed below in Table 35.

Table 35: VOC and HAP emissions from aviation gasoline [tons]*

Total VOC Emissions	**6.28**
Total HAP Emissions	**0.33**

*Emissions for aviation gasoline fueling are estimated from data sourced from the 2017 EPA National Emission Inventory Database and assumed to be realistic estimations of aviation gasoline fueling emissions for 2020.

5. Gravel Pits

Description of Sources

Twelve sand and gravel pits operated within the exterior boundaries of the Reservation during calendar year 2020. Data was collected from the Colorado Division of Reclamation

[23] U.S. EPA. (2008, October). Lead Emissions from the use of Leaded Aviation Gasoline in the United States. Retrieved from: https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1004MXJ.TXT.

Mining and Safety (DRMS) database[24]. The emissions from pits on the Reservation were estimated by scaling down the emissions estimates reported to the 2017 EPA NEI for La Plata and Archuleta counties for calendar year 2017.

Data Collection

The AQP identified active gravel pits located within the exterior boundaries of the Reservation through the DRMS ArcGIS data set. AQP identified the gravel, sand, and combined sand and gravel permits located within the exterior boundaries of the Reservation in La Plata and Archuleta counties. Permits with an active status for 2020 were then cross-referenced with the DRMS Imaged Document data to determine if there was production in 2020. This methodology determined nineteen active gravel pits in La Plata County and three active gravel pits in Archuleta County during 2020.

Emissions

Gravel pit emissions for La Plata County were obtained from the EPA's calendar year 2017 Nonpoint Emission Inventory for gravel pits. Emission totals were reported to NEI for La Plata and Archuleta counties and not for individual gravel pits. To derive emission estimates for the Reservation, the reported emission totals for La Plata County were downscaled by the percentage of the affected acreage of active gravel pits that are located within the exterior boundaries of the Reservation. For example, 30.71% of the affected acreage of active gravel pits in La Plata County are within the Reservation boundaries, therefore, gravel pits on the Reservation account for 30.71% percent of emissions in La Plata County. Emission totals for 2020 are displayed below in Table 36.

Table 36: Emissions of PM_{10} and $PM_{2.5}$ from active gravel pits

County	Pollutant	County emissions [tpy]	Percent of active permitted pits within SUIR	Reservation Emissions [tpy]
La Plata	**PM_{10}**	176.38	30.71%	54.16
La Plata	**$PM_{2.5}$**	22.05	30.71%	6.77
Archuleta	**PM_{10}**	29.40	10.88%	3.20
Archuleta	**$PM_{2.5}$**	3.67	10.88%	0.40

6. Residential Heating

A. Description of Sources: Fireplaces and Wood Burning Stoves

[24] Colorado Division of Reclamation Mining and Safety. (2021). *Active Hardrock Permits.* Department of Natural Resources. Retrieved from https://maps.dnrgis.state.co.us/drms/Index.html?viewer=drms.

Fireplaces and wood burning stoves are a significant source of residential heating within the exterior boundaries of the Reservation. The predominant types of solid fuel available are pinyon-juniper, pine, and aspen.

Data Collection

The U.S. Census 2015-2019 American Community Survey 5-Year Estimate (survey) was used to determine the number of households on the Reservation that use fireplaces or wood burning stoves for residential heating.[25] The survey estimates the total number of households on the Reservation that used wood as a heating source during the five-year survey period.

The U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics' 2015 Residential Energy Consumption Survey (EIA) was used to obtain the average number of cords used within a year at an average household.[26] Table CE7.2 of the EIA lists the household wood consumption as 35.2 million BTU . Utah State University Forestry Extension lists the Heating Value per Cord in million BTU from which an average heating value for the predominant types of solid fuel available of pinyon-juniper, pine, and aspen was calculated. The average heating value per cord of 22.4 million BTU was used to calculate an average household usage of 1.6 cords per year. The U.S. Census reported 925 households on the Reservation use fireplaces or woodstoves as the primary heating source.

Fireplace and wood burning residential heating data for the Southern Ute Indian Reservation in 2020 is displayed below in Table 37.

Table 37: Fireplace and wood burning residential heating data

Homes heated with wood	Average fuel use per household/year	Unit of measurement	Total number of cords used in 2020
815	1.6	Cords	1304

Emission Calculation Methodology

Emissions for residential fireplace and wood burning stoves were calculated using the Tribal Emissions Inventory Software Solutions (TEISS) emission calculator. The calculator employed emission factors from EPA AP-42 Section 1.10.2, which may be adjusted based on the units of data input.

Example Calculations

[25] U.S. Census Bureau. (2019). 2015-2019 American Community Survey 5-Year Estimates. Retrieved from https://data.census.gov/cedsci/

[26] U.S. Energy Information Administration. (2021) Table CE7.2 Household wood consumption in the U.S. – totals and averages, 2015. Retrieved from: https://www.eia.gov/consumption/residential/data/2015/c&e/pdf/ce7.2.pdf.

Wood Type	Heating Value Mm BTU/cord
Western Juniper	21.8
Pinyon	27.1
Quaking Aspen	18.2
Average	**22.4**

35.2 mmBTU x 1 cord = 1.6 cords (input into TEISS)
22.4 mm BTU

815 households x 1.6 cord = 1,304 cords (input into TEISS)
household

Assumptions

The U.S. Census surveyed 5,102 households and reported 815 with an estimated uncertainty of ± 206 households on the Reservation use fireplaces or woodstoves for home heating. The TEISS variables chosen were conventional pre-phase I wood stove, Rocky Mountain and Pacific Coast region with Ponderosa Pine Hardwood Forest.

Emissions

Total criteria pollutant and GHG emissions from residential fireplace and wood-burning stoves on the Reservation in 2020 are displayed below in Table 38.

Table 38: Criteria pollutant and GHG emissions from fireplaces and wood burning stoves [tons]*

Pollutant	NOx	SO_2	PM_{10}	CO	VOC	GHG (CO_2e)
Total	1.87	0.27	20.49	154.54	35.49	5629.94

*GHG reported in metric tonnes.

B. Description of Sources: Propane Heating

Liquid propane (LP) is the dominant source of residential heating on the Reservation and in Southwest Colorado.

Data Collection

The U.S. Census 2015 -2019 American Community Survey 5-Year Estimate was used to determine the number of households on the Reservation that use LP gas as a source of heating.

The U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics' 2015 Residential Energy Consumption Survey (EIA) was used to obtain the average of LP used per household. The survey estimated the average number of gallons of LP used within a year for an average household.[27] The U.S. Census surveyed 5,102 households and reported 2,555 with an estimated uncertainty of ± 331 households on the Reservation use LP gas as the primary heat source and the EIA estimated 278 gallons of LP gas are burned per year in households in Colorado.

Liquid Propane residential heating data for the Southern Ute Indian Reservation in 2020 is displayed below in Table 39.

Table 39: Liquid propane residential heating data

Homes Heated with Liquid Propane	Average Fuel Use per Household/Year	Unit of Measurement	Total Gallons used in 2020
2,555	278	Gallons	710,290

Emission Calculation Methodology

Emissions for residential LP gas heating were calculated using the TEISS emission calculator. The calculator employed emission factors from EPA AP-42 Section 1.5.

Example Calculation

$$\frac{2{,}555 \text{ households} \times 278 \text{ gallons}}{\text{household}} = 710{,}290 \text{ gallons *(input into TEISS)}$$

Assumptions

The U.S. Census surveyed 5102 households and reported 2,555 with an estimated uncertainty of ± 331 households on the Reservation use LP gas for home heating. The actual sulfur content of LP gas on the Reservation is unknown and the default sulfur content of 0.54 grains/100 ft^3 was used in the TEISS emission calculator.

Emissions

Total criteria pollutant and GHG emissions from residential LP gas usage on the Reservation in 2020 is displayed below in Table 40.

[27] U.S. Energy Information Administration. (2021). Table CE2.5 Household Site Fuel Consumption in the West Region, Totals and Average, 2015 Physical Units. Retrieved from https://www.eia.gov/consumption/.

Table 40: Criteria pollutant and GHG emissions from liquid propane gas heating at residential sources [tons]*

Pollutant	NOx	SO_2	PM_{10}	CO	VOC	GHG (CO_2e)
Total	4.76	0.02	0.01	1.35	0.19	4080.06

*GHG reported in metric tonnes.

C. Description of Sources: Natural Gas Heating

Natural gas is a prevalent residential heating fuel on the Reservation.

Data Collection

The U.S. Census 2015-2019 American Community Survey 5-Year Estimate (survey) was used to determine the number of households on the Reservation that use natural gas for residential heating. The survey estimates the total number of households on the Reservation that used natural gas as a heating source during the five-year survey period.

The U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics' 2015 Residential Energy Consumption Survey (EIA) was used to obtain the average of natural gas used per household. The survey estimated the average cubic feet of natural gas used within a year for an average household. The U.S. Census reported 1017 or 20% of households on the Reservation use natural gas as the primary heat source and the EIA estimated 48.3 thousand cubic feet (48.3 Mcf) of natural gas are burned per year in households in Colorado.

Natural Gas residential heating data for the Southern Ute Indian Reservation in 2020 is displayed below in Table 41.

Table 41: Natural gas residential heating data

Homes Heated with Natural Gas	Average Fuel Use per Household/Year	Unit of Measurement	Total MMcf used in 2017
1017	0.0483	MMcf	49.12

Emission Calculation Methodology

Emissions for residential natural gas heating were calculated using the TEISS emission calculator. The calculator employed emission factors from EPA AP-42.

Example Calculation

$$\frac{1017 \text{ household} \times 0.0483 \text{ MMcf gas}}{\text{household}} = 49.12 \text{ MMcf gas (input into TEISS)}$$

Assumptions

The U.S. Census surveyed 1,017 households with an estimated uncertainty of ± 208 households that use natural gas for home heating. TEISS input variables were the EPA AP-42 default heating value of 1020 Btu/ft^3 and sulfur content of 2000 grains/ $MMft^3$.

Emissions

Total criteria pollutant and GHG emissions from residential natural gas heating sources on the Reservation in 2020 are displayed below in Table 42.

Table 42: Criteria pollutant and GHG emissions from natural gas heating at residential sources [tons]*

Pollutant	NOx	SO_2	PM_{10}	CO	VOC	GHG (CO_2e)
Total	2.31	.01	.05	0.98	0.14	2661.35

*GHG reported in metric tonnes.

7. Agricultural Burning

Description of Activity

Agricultural burning is performed on the Reservation to clear irrigation ditches of vegetation and to clear pastures of weeds and vegetation prior to crop cultivation.

Data Collection

Emissions from agricultural burning on the Reservation were obtained from the 2017 NEI for La Plata County and 2014 NEI Archuleta County as the 2017 NEI contained no data for Archuleta. EPA reported two types of agricultural burning: Agricultural Burning Grasses, and Agricultural Burning Unspecified Crop Type. EPA did not report emissions for Agricultural Burning Unspecified Crop Type for Archuleta County. Emissions were not included in this emissions inventory for Montezuma County due to only 0.2% of the county falling within the Reservation boundaries.

Emission Calculation Methodology

Emissions obtained from the NEI for La Plata and Archuleta County were scaled down proportionally to the percentage of land in La Plata and Archuleta counties that fall within the exterior boundaries of the Reservation. 38.9% and 29.5 % respectively.

Assumptions

AQP assumes the methods and calculations used to develop emissions from agricultural burning are valid and acknowledges that the process used to reduce emissions for the Reservation could result in a slight under or overestimation of emissions. It is also assumed that emissions from agricultural burning from the 2014 and 2017 NEI are realistic estimations that occurred in 2020.

Emissions

Criteria pollutants, NH_3, and HAP emission estimates from agricultural burning that occurred within the exterior boundaries of the Reservation in 2020 are displayed below in Table 43.

Table 43: Criteria pollutant, NH_3, and HAP emissions from agricultural burning [tons]*

Pollutant	PM_{10}	$PM_{2.5}$	CO	NOx	NH_3	SO_2	VOC
Total	1.40	1.03	8.05	0.19	0.55	0.07	0.67

*Emissions for agricultural burning were estimated from data retrieved from the 2014 and 2017 EPA National Emission Inventory Database and are assumed to be realistic estimations of agricultural burning emissions that occurred in 2020.

VI. Mobile Sources

Description of Sources

Mobile source emissions are generated from on-road vehicles and non-road engines including lawn equipment, recreational vehicles, agricultural equipment, construction equipment, etc.

1. On-Road Mobile Sources

AQP estimated emissions for on-road mobile sources using EPA's 2017 NEI county level mobile emissions data to estimate Reservation specific mobile emissions. On-road mobile sources in 2017 NEI county level data include emissions from motorized vehicles that are normally operated on public roadways. This includes diesel and non-diesel (gasoline, compressed natural gas (CNG), and ethanol, etc.) fueled on-road mobile sources such as passenger cars, motorcycles, minivans, sport-utility vehicles, light-duty trucks, heavy duty trucks, and buses. The sector includes emissions generated from parking areas as well as emissions while the vehicles are moving.

Data Collection

Data were collected from EPA's 2017 NEI county level mobile emissions.

Emission Calculation Methodology

The 2017 NEI is comprised of mobile emission estimates calculated based on the MOVES model run with S/L/T submitted activity data when provided, except for California and tribes, for which the NEI includes submitted emissions. In cases where S/L/T submitted data is not provided, EPA-developed default activity based on data from the Federal Highway Administration.

Data values were derived from 2017 NEI for both La Plata and Archuleta counties. Data adjustments were made to the emission totals for each county based on the percentage of road miles in La Plata and Archuleta County that fall within the exterior boundaries of the Reservation, as determined from GIS shapefiles obtained from the La Plata and Archuleta County GIS departments.[28,29] The data adjustment resulted in a reduction of the emissions to 35% and 17% for La Plata and Archuleta Counties, respectively. No significant roads on the Reservation are located in Montezuma County, and therefore AQP assumed on-road emissions for Montezuma County to be negligible. The AQP determined that 947.3 miles of roads are within the Reservation boundaries. The AQP later combined the two adjusted county level datasets to obtain Reservation emission totals. Data outputs were organized by criteria pollutants emissions.

Assumptions

AQP assumed that data from the 2017 NEI to be the best available data for estimating 2020 on-road mobile emissions on the Reservation.

Emissions

Criteria pollutant emissions from on-road mobile sources on the Reservation in 2017 are displayed below in Table 44.

Table 44: Criteria pollutant emissions from on-road mobile sources [tons]

Pollutant	CO	NOx	VOC	PM_{10}	$PM_{2.5}$
Emissions	1590.27	383.96	216.13	16.99	10.63

2. Non-Road Mobile Sources

Non-road mobile sources contribute a significant portion of the NOx and CO emissions from mobile sources. Non-road mobile sources on the Reservation include agricultural equipment, construction and mining equipment, lawn and garden equipment, and

[28] La Plata County. (2018). *Roads.* GIS/Mapping. Retrieved from ftp://ftp.laplata.co.us/shapefiles/.

[29] Archuleta County. (2018). *Roads - Archuleta County.* GIS. Retrieved from http://www.archuletacounty.org/504/Download-GIS-Data.

recreational equipment fueled by gasoline, diesel, other sources (CNG and liquified petroleum gas (LPG), etc.).

Data Collection

Data were collected from EPA's 2017 NEI county level mobile emissions.

Assumptions

AQP assumed that data from the 2017 NEI to be the best available data for estimating 2020.

Emission Calculation Methodology

The 2017 NEI used MOVES2014b version of EPA's Motor Vehicle Emissions Simulator (MOVES) Model, to estimate non-road emissions. All the input and activity data required to run the non-road component of MOVES model (MOVES-Nonroad) are contained within the MOVES default database, which is distributed with the model. State- and county-specific data can be used by creating a supplemental database known as a county database (CDB) and specifying it in the MOVES run specification (runspec). State, local and tribal (S/L/T) agencies can update the data within the CDBs to produce emissions estimates that accurately reflect local conditions and equipment usage. MOVES first uses the data in the CDBs and fills in any missing data from the MOVES default database.

Data values for non-road emissions were derived from 2017 NEI for both La Plata and Archuleta counties. The emissions for La Plata and Archuleta County were reduced to 38.9% and 29.5% respectively based on the portion of these counties within the exterior boundaries of the Reservation. The AQP later combined the adjusted emissions data sets from La Plata and Archuleta counties to obtain Reservation emission totals.

Emissions

Criteria pollutant emissions from non-road mobile sources on the Reservation in 2017 are displayed below in Table 45.

Table 45: Criteria pollutant emissions from non-road mobile sources [tons]

Pollutant	CO	NOx	VOC	PM_{10}	$PM_{2.5}$
Emissions	816.51	50.67	90.10	6.58	6.23

VII. Events

1. **Wildland Fires and Prescribed Burns**

Description of Activity

The forest on the Reservation is predominantly comprised of pinyon-juniper woodlands with ponderosa, gambel oak, aspen and sub-alpine forest at higher elevation areas. The forest is prone to wildfire and prescribed burns are utilized as a forest management strategy to help prevent catastrophic fires, improve wildlife habitat, and improve overall forest health. Wildfires and prescribed burns can be significant sources of air pollution on the Reservation and the Four Corners area.

Data Collection

Wildland and prescribed burn fire (forest fire) data for calendar year 2020 were obtained from the Bureau of Indian Affairs (BIA) and the Southern Ute Agency Fire Management Division.[30] The initial data identified 32 fires (31 wildfires and 1 prescribed fires). Data sets included type of fire, latitude and longitude of fire perimeter, and acres burned.

Emission Calculation Methodology

Forest fire emission estimates were calculated using the USFS BlueSky Playground web tool (BlueSky).[31] BlueSky is comprised of several internal USFS datasets and modeling programs, including the Fuels Characteristic Classification System fuel information dataset (FCCS), the CONSUME3 fuel consumption model, and the FEPS emission factors model.

Forest fire data including latitude and longitude and acres burned are input into BlueSky and BlueSky selects the correct default model input values based on the fire location. Input values include available fuel load, fuel consumed, emission factors, and meteorological forecast data. "Dry" was selected for the fuel moisture value. Forest fire event by FCCS fuel bed type are displayed below in Table 46.

Table 46: Forest fire occurrence by fuels characteristic classification system, fuel bed type, and acres burned

FCCS Fuel Bed Description	Number of Fires	Acres Burned
Ponderosa Pine Savanna	3	3.5
Tobosa-Grama Grassland	1	6
Pinyon-Utah Juniper Woodland	25	234.85
Low Sagebrush Shrubland	2	1.1
Totals	**31**	**245.45**

[30] Bureau of Indian Affairs Fire Management. (2020). *Southern Ute 2020 Fire Occurrence*

[31] U.S. Forest Service AirFire Research Team. (2020). *BlueSky Playground (Version 2.0 beta)*. Retrieved from https://playground.airfire.org/ .

Emission Equations

Emissions = (Area burned) x (Fuel Load Available) x (Fuel Consumed (Burn Efficiency)) x (Emission Factors)

Mass of Emissions =
Area burned (input from AQP datasets)
Fuel Load Available (updated FCCS map)
Fuel Consumed (CONSUME3)
Emission Factors (FEPS plus HAPs)

Bluesky Playground Framework

Assumptions

Collected and reported fire related data is assumed to be accurate and to be the best data available. BlueSky is assumed to function as intended and to select the proper fuel characteristics from the USFS FCCS map when latitude and longitude coordinates are input into the model.

Emissions

Total criteria pollutant, NH_3 and GHG from prescribed burns and wildland fires that occurred within the exterior boundaries of Reservation boundaries in 2020 are displayed below in Table 47.

Table 47: Criteria pollutant, NH_3, and GHG emissions from prescribed burns and wildland fires [tons]*

Pollutant	PM_{10}	$PM_{2.5}$	CO	NOx	NH_3	SO_2	VOC	GHG (CO_2e)
Total	13.34	11.19	123.71	2.41	2.02	1.14	29.35	1873.41

*GHG reported in metric tonnes.

VIII. Biogenic

Biogenic processes of trees, vegetation, soil, and microbial activities generate VOC, NOx, CO, and HAP emissions. EPA estimates biogenic emissions for triennial inventory years, with the last estimation performed for calendar year 2017.

Assumptions

The AQP assumed the emission estimations prepared by EPA to be performed correctly and to be the best available emissions estimates for 2020.

Emission Calculation Methodology

Biogenic emissions estimated for La Plata and Archuleta County were prepared by EPA using the EPA's Biogenic Emission Inventory System and Biogenic Emissions Land Use Database.[32] AQP obtained the 2017 emission estimates for La Plata and Archuleta counties from the 2017 NEI. Emissions estimates for Montezuma County were not included in this emissions inventory due to only 0.2% of the county falling within the Reservation boundaries.

County wide emissions were reduced for La Plata and Archuleta County to 38.9% and 29.5% respectively, based on the area of each county that is located within the exterior boundaries of the Reservation.

Emissions

Criteria pollutant and HAP emissions from biogenic sources on the Reservation in 2020 are displayed below in Table 48.

Table 48: Criteria pollutant and HAP emissions from biogenic sources [tons]*

Pollutant	CO	NOx	VOC	HAP
Emissions	879.43	408.03	5,483.95	662.79

*Emissions for biogenic sources were estimated from data retrieved from the 2017 EPA National Emission Inventory data and are assumed to be realistic estimations of biogenic source emissions for 2020.

IX. Summary

1. Emissions Sources

Reservation emissions presented in this inventory are distributed between point, non-point, mobile, and biogenic sources.

A. Point Sources

There are four categories of point sources including:

1) Title V permitted oil and gas sources,
2) TMNSR permitted and true minor oil and gas sources,
3) Municipal solid waste landfills, and
4) Airports.

B. Non-Point Sources

There are eight categories of non-point sources including:

[32] U.S. Environmental Protection Agency. (2021). Biogenic Emission Inventory System. Retrieved from https://www.epa.gov/air-emissions-modeling/biogenic-emission-inventory-system-beis.

1) Small oil and natural gas sources,
2) Fruitland Formation Outcrop natural gas seeps
3) Gasoline stations,
4) Aviation gasoline dispensing,
5) Gravel pits,
6) Residential heating,
7) Fire events (wildland fires and prescribed burns), and
8) Agricultural burning.

C. Mobile Sources

Mobile sources are divided into two categories:

1) On-road, and
2) Non-road.

D. Biogenic Emissions

Biogenic emissions encompass all non-man-made emission sources.

2. Emission Inventory Findings

A summary of 2020 criteria pollutant, HAP, and GHG emissions by source category is displayed below in Table 49.

Table 49: Criteria pollutant, HAP, and GHG emissions on the Southern Ute Indian Reservation [tons]*

Source Category	NOx	VOC	SO2	PM10	CO	Total HAP	GHG (CO2e)
Point Sources							
Title V Oil and Gas	2,359.76	1,032.92	46.85	101.94	1,872.89	306.09	2,124,765.29
Synthetic Minor Oil and Gas	253.89	126.22	5.86	3.75	137.54	29.68	69,931.40
True Minor Oil and Gas	4,575.24	834.57	16.07	42.81	3,248.08	290.97	1,568,843.62
Municipal Solid Waste Landfills	-	7.09	-	15.21	0.30	3.55	23,226.65
Airports	36.47	13.94	5.02	4.50	217.11	0.31	-
Total Point Source Emissions	7,225.37	2,014.75	73.80	168.20	5,475.92	630.61	3,786,766.97
Non-Point Sources							
Small Oil and Gas Sources	11,664.00	879.10	5.63	112.01	9,716.55	233.90	1,618,203.64
Fruitland Formation Outcrop	-	-	-	-	-	-	5,923,341.15
Gas Stations	-	16.84	-	-	-	-	-
Aviation Gasoline	-	6.27	-	-	-	-	-
Gravel Pits	-	-	-	57.36	-	-	-
Residential Heating	8.94	35.81	0.30	20.68	156.88	-	12,371.35
Fire Events	2.41	29.35	1.14	13.34	123.71	-	1,873.41
Agricultural Burning	0.19	0.67	0.07	1.39	8.05	-	-
Total Non-Point Source Emissions	11,675.54	968.04	7.14	204.79	10,005.19	233.90	7,555,789.54
Mobile Sources							
Mobile Sources	434.64	306.23	-	23.57	2,406.78	-	-
Biogenic Sources							
Biogenic	408.03	5,483.95	-	-	879.43	662.79	-
Total Emissions							
Total:	19,743.58	8,772.97	80.94	396.57	18,767.33	1,527.29	11,342,556.51

*GHG gas emissions reported in metric tonnes.

Oil and natural gas production and mid-stream transmission are the predominant industries on the Reservation. Of all the quantified emission categories, oil and gas contributed the most significant quantities of NOx, CO, SO_2 and PM_{10} to the airshed during 2020. Oil and gas related activities accounted for 18,852.9 tons, or 95% of the total NOx emissions quantified in the emission inventory; CO emissions accounted for 80% of the total quantified CO emissions, 14,975.1; SO_2 accounted for 92% of the total quantified SO_2 emissions, 74.4 tons; PM_{10} accounted for 77% of the total quantified PM_{10} emissions, 260.5 tons; and HAP emissions accounted for 56% of the total quantified HAP emissions, 860.6 tons.

Biogenic sources are the most significant source of VOC emissions to the airshed. VOC emissions from this category account for 63% of the total VOC emissions to the airshed at 5,483.9 tons.

The Fruitland Outcrop is the most significant source of GHG emissions, calculated to be 5,923,341.1 metric tons, or 52% of total Reservation emissions.

NOx, CO, VOC, and HAP emissions by source category on the Reservation in 2020 are displayed below in Figures 30 and 31.

Figure 30: NOx and CO emissions by source category [tons]

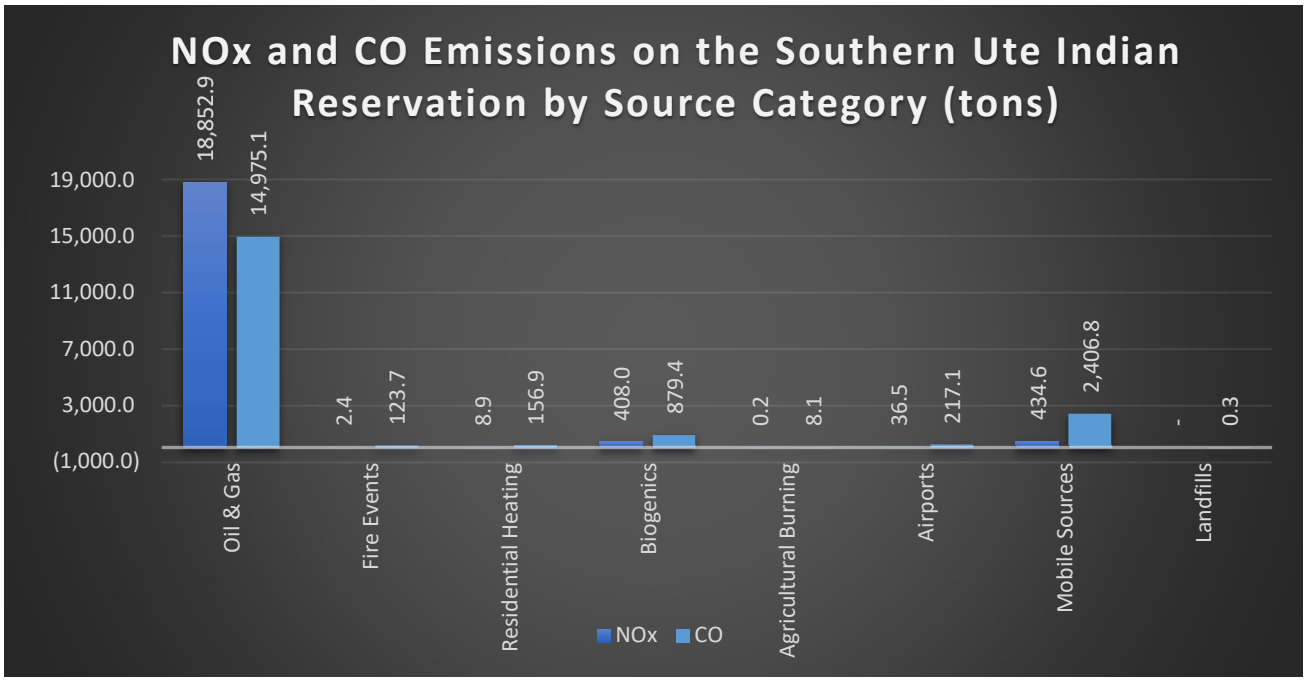
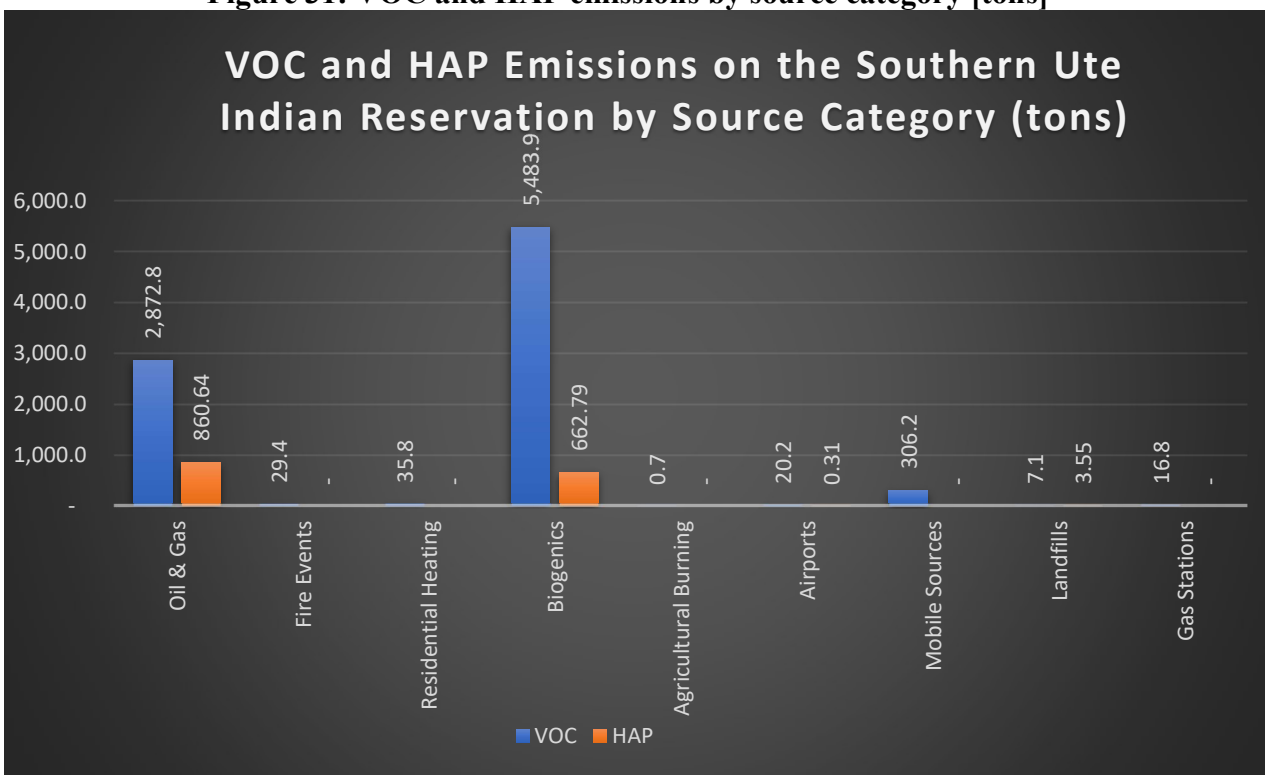


Figure 31: VOC and HAP emissions by source category [tons]*



*Airport emissions include the point airport emissions as well as the non-point aviation gasoline emissions.

Due to the lack of accurate emission factors and reliable data, GHG emissions were not estimated for every category presented in this inventory. Several categories that were not evaluated or quantified, such as mobile sources and biogenic sources, would be expected to contribute significant emissions of GHG.

3. Oil and Gas Emissions Summary

The bulk of the emission sources within the point source category are larger emission sources such as natural gas compressor stations, central delivery points, treating plants, and processing plants. Combined, the Title V, permitted TMNSR, and true minor sources represent the bulk of NOx, CO, PM10, SO_2, and non-biogenic VOC and HAP emissions.

Within the oil and gas sector, non-point source, small oil and gas sources such as production well sites, contribute the most NOx, CO, and PM_{10} emissions to the airshed in contrast to the larger Title V, permitted TMNSR, and true minor sources. This is due to the large number of small oil and gas sources, 2,582 sites, operating within the exterior boundaries of the Reservation. This category alone accounts for 62% of the total airshed NOx emissions at 11,664.0 tons and 65% of the total CO emissions at 9,716.6 tons. Emissions of particulate matter 10 micrometers or less in diameter were 112.0 tons, or about 43% of the total airshed emissions. Emissions totals from oil and gas sector sources are displayed below in Table 50 and Figures 32 through Figures 34.

Table 50: Emissions from oil and gas sector sources [tons]*

Pollutant	NOx	VOC	SO2	PM10	PM2.5	CO	GHG (CO2e)	Total HAP
Title V	2,359.8	1,032.9	46.9	101.9	-	1,872.9	2,124,765.3	306.1
Synthetic Minor	253.9	126.2	5.9	3.8	-	137.5	69,931.4	29.7
True Minor	4,575.2	834.6	16.1	42.8	-	3,248.1	1,568,843.6	291.0
Small Oil & Gas Sources	11,664.0	879.1	5.6	112.0	71.8	9,716.6	1,618,203.6	233.9
Totals:	**18,852.9**	**2,872.8**	**74.4**	**260.5**	**71.8**	**14,975.1**	**5,381,744.0**	**860.6**

*GHG emissions reported in metric tonnes.

Figure 32: NOx and CO emissions from oil and gas sources [tons]

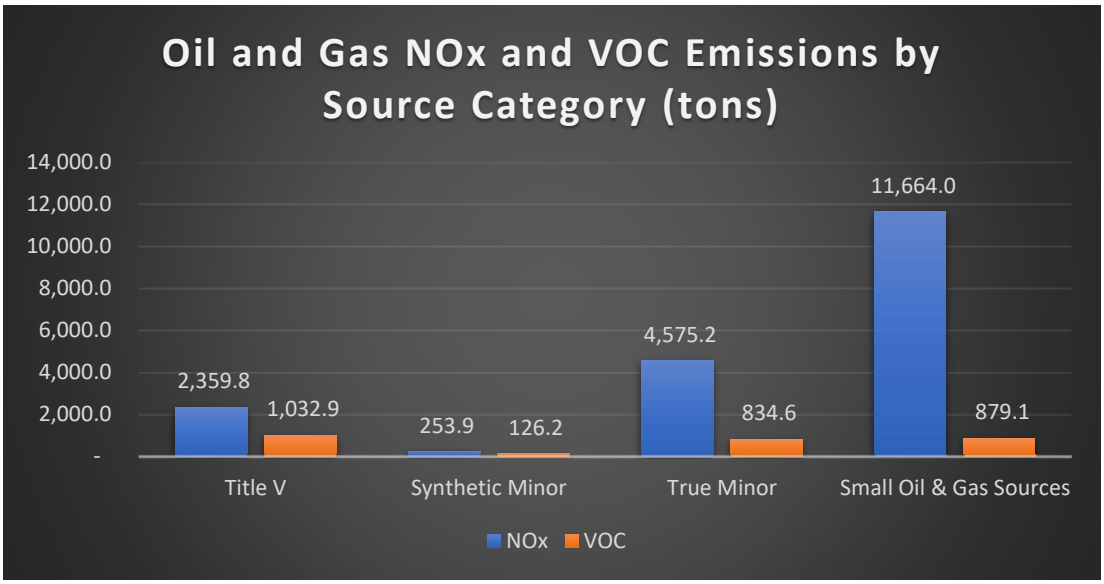


Figure 33: VOC and HAP emissions from oil and gas sources [tons]

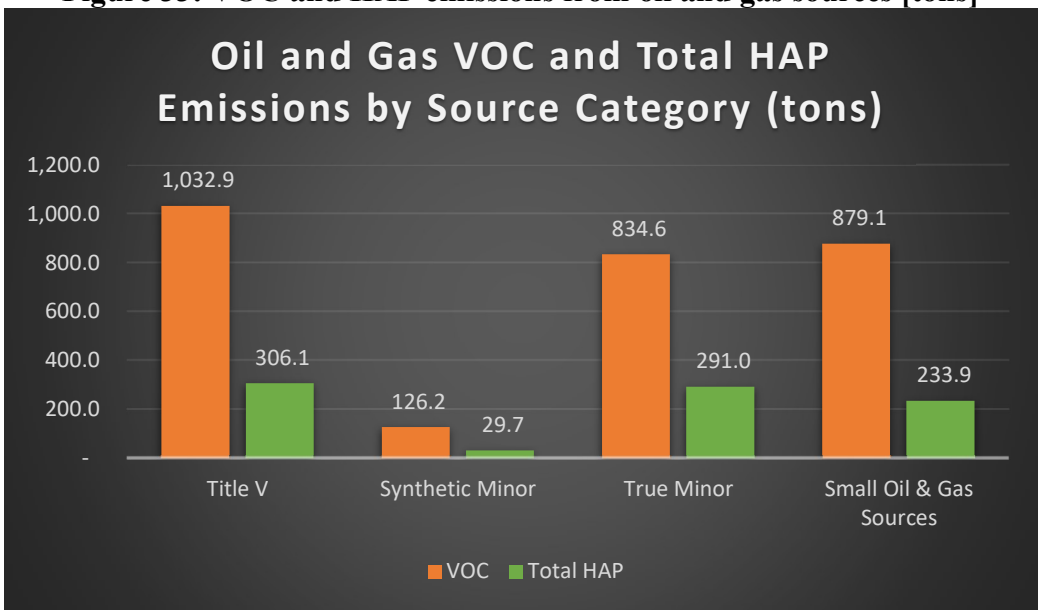
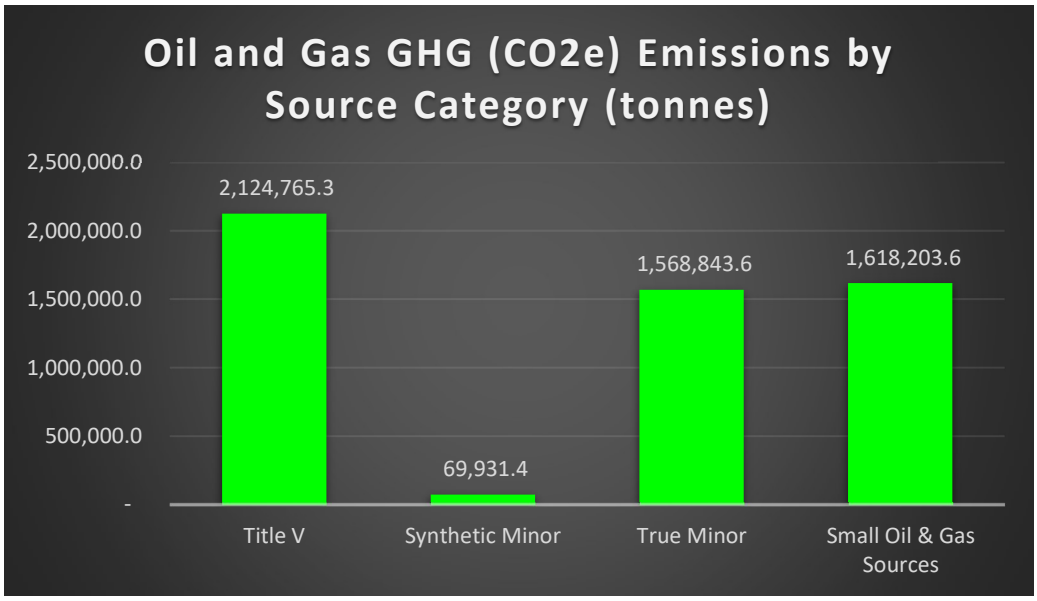


Figure 34: GHG (CO_2e) emissions from oil and gas sources [tonnes]

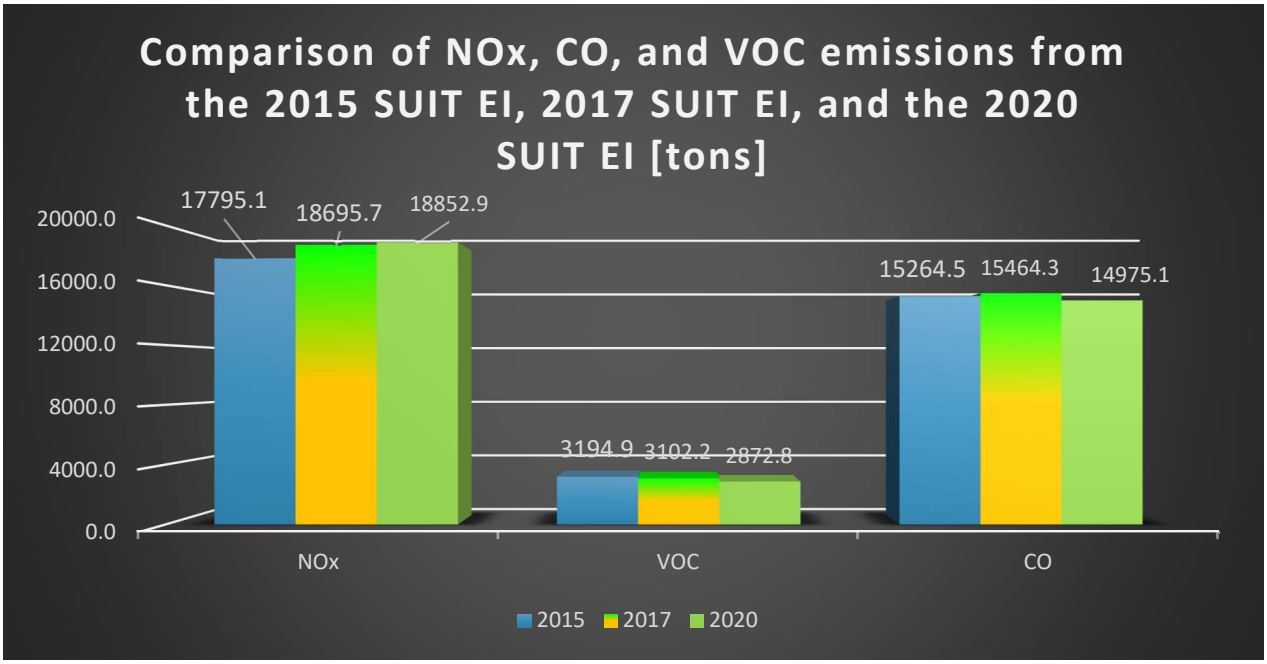


Within the small oil and gas sources, the emission unit type that contributed the most NOx and CO emissions were natural gas-fired reciprocating internal combustion engines (RICE). Four-stroke rich burn (4SRB) engines between 0-50 hp and 4SRB engines between 51-100 hp were the largest emitting subcategories.

4. Comparison of the 2020 SUIT EI to Previous Emissions Inventories

To evaluate the representativeness of oil and gas emission estimations from this 2020 SUIT emissions inventory, the AQP has compared the results with oil and gas emission estimates for the Reservation from the *2015 Southern Ute Indian Reservation Emission Inventory* (2015 SUIT EI) and the *2017 Southern Ute Indian Reservation Emission Inventory* (2017 SUIT EI)

Figure 35: Comparison of NOx, CO, and VOC emissions from the 2015 SUIT EI, 2017 SUIT EI, and the 2017 SUIT EI [tons]

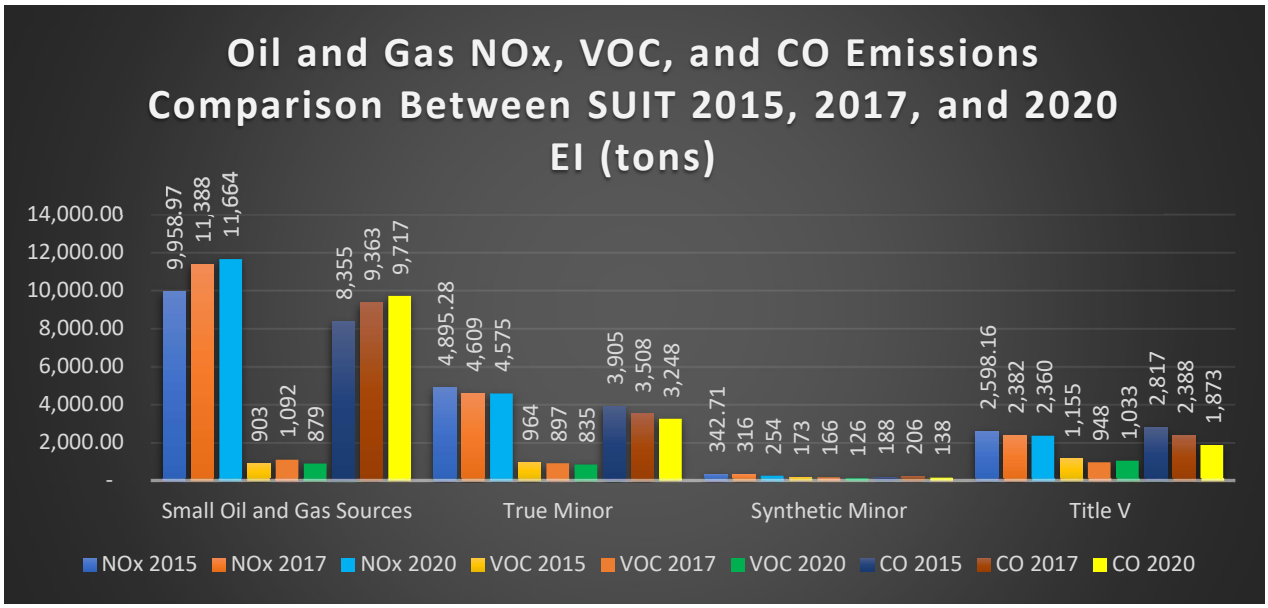


A comparison of the 2015 SUIT EI, 2017 SUIT EI, and 2020 SUIT EI shows a 1,057.8 ton increase in NOx emissions and a 289.4 ton decrease in CO emissions between 2015 and 2020 at oil and gas point sources and non-point sources. AQP attributes the increased NOx emissions and decrease in CO emissions to 91 more lean burn engines being reported in 2020 than in 2015 and 46 less rich burn engines at the non-point oil and gas sources.

Between the 2015 and 2020 SUIT EIs, emissions decrease trends were observed at oil and gas point sources. True minor sources, synthetic minor, and Title V sources showed a decrease in NOx, CO, and VOC emissions. AQP attributes the decreases in NOx and VOC emissions to decreased oil and gas production on the Reservation between 2017 and 2020.

A comparison of NOx, CO and VOC emissions at oil and gas sources on the Reservation from the 2020 SUIT EI and the 2017 SUIT EI is displayed below in Figure 36.

Figure 36: Comparison of oil and gas NOx, CO, and VOC emission estimations for the Southern Ute Indian Reservation from the 2015, 2017, and 2020 SUIT EIs [tons]


Oil and Gas NOx, VOC, and CO Emissions Comparison Between SUIT 2015, 2017, and 2020 EI (tons)
14,000.00
12,000.00
10,000.00
8,000.00
6,000.00
4,000.00
2,000.00
-
9,958.97
11,388
11,664
903
1,092
879
8,355
9,363
9,717
4,895.28
4,609
4,575
964
897
835
3,905
3,508
3,248
342.71
316
254
173
166
126
188
206
138
2,598.16
2,382
2,360
1,155
948
1,033
2,817
2,388
1,873
Small Oil and Gas Sources
True Minor
Synthetic Minor
Title V
NOx 2015
NOx 2017
NOx 2020
VOC 2015
VOC 2017
VOC 2020
CO 2015
CO 2017
CO 2020

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40 CFR Part 98 - Mandatory Greenhouse Gas Reporting. (2020). U.S. Government Publishing Office. Retrieved from http://www.ecfr.gov/cgi-bin/text-idx?SID=32c4baa0d0aff54fa651d1cdb1cd7934&mc=true&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl

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XI. Appendix – Quality Assurance Review

Description of Quality Assurance Review

To meet the EPA emissions inventory level II data quality objective of conducting a third party quality assurance (QA) review, the AQP contracted with Ramboll. The QA review included the review of the data collection methodology, data, assumptions, emission factors, calculation methodologies, and emission totals. An abridged version of the final QA report is attached as an Appendix. A full version of the QA report, which contains all of the QA review forms can be requested from the AQP.

Appendix B: CARB Report

CARB's Oil and Gas Methane Regulation
2018 Annual LDAR Summary

October 2020 (Revised January 2022)

California Air Resources Board

Table of Contents

A. Key Findings

- During the first year of implementation of CARB's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities[1] (Oil and Gas Methane Regulation), the leak detection and repair (LDAR) surveys resulted in a 29% reduction in emissions from components subject to the regulation (e.g., valves, flanges, and connectors).
- Total emission reductions were estimated to be ~5,400 metric tons methane, or ~140,000 metric tons CO_2e.[2]
- Less than 1% of the unique components surveyed were found leaking at or above the regulatory threshold of 10,000 ppmv.
- Approximately 20% of the leaks accounted for 50% of the emissions.
- The natural gas transmission sector had the largest ratio of leaks to components surveyed (2.08%), but the smallest number of components surveyed. The crude oil production sector had the largest number of components surveyed, but the smallest ratio of leaks to components surveyed (0.36%).
- Leaks were most commonly identified from connectors and valves, while open-ended lines had the highest estimated leak rates on average.

B. Background

As an early action measure to achieve the emission reductions required by the California Global Warming Solutions Act (AB 32), CARB adopted the Oil and Gas Methane Regulation to reduce methane emissions from oil and gas production, processing, storage, and transmission compressor stations. CARB's Oil and Gas Methane Regulation was adopted by the Board on March 23, 2017 and went into effect on January 1, 2018. Section 95669 requires owners/operators of oil and natural gas facilities[3] to conduct quarterly LDAR surveys to monitor components for leaks and repair detected leaks within a specified time frame. Quarterly LDAR inspections began on January 1, 2018, and operators are required to submit annual LDAR reports to CARB by July 1 of each calendar year.[4] The following information must be included in operators' annual LDAR reports:

1. Total number of components inspected
2. Total number of leaks identified per leak threshold category (10,000 to 49,999 ppmv, and 50,000 ppmv or greater)[5]
3. For each leak:

[1] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4. Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.
[2] CO_2e was calculated throughout the report using the 100-year global warming potential (GWP) of methane of 25.
[3] Including oil and gas production, processing, and storage; natural gas gathering and boosting stations; natural gas underground storage; and natural gas transmission compressor stations.
[4] The deadline for 2018 reporting was extended from July 1, 2019 to August 30, 2019 to allow for the Oil and Gas Methane Regulation module of the web-based reporting tool, Cal e-GGRT, to come online.
[5] After January 1, 2020, operators will also be required to report leaks ranging from 1,000 to 9,999 ppmv.

a. Inspection date
b. US EPA Method 21 instrument used
c. US EPA Method 21 instrument calibration date
d. Component type
e. Equipment ID for the equipment the leaking component is on, if applicable
f. Initial leak concentration
g. Repair date
h. Concentration after repair

This Annual LDAR Summary is based on data received from 69 operators who submitted 309 annual reports for LDAR activities that occurred during 2018.

The LDAR requirements in CARB's Oil and Gas Methane Regulation do not apply to all components in California; there are two key exemptions. First, components that are subject to local air district LDAR requirements that were in place prior to January 1, 2018 are exempt from LDAR requirements in CARB's Oil and Gas Methane Regulation because the regulation was intended to cover components that were not already subject to district LDAR requirements.[6] Second, components handling crude oil with an API gravity less than 20 are not subject to LDAR requirements due to their very low emissions levels relative to other components found in gas or other liquid service (less than 1% of all emissions from leaking components in the state).[7,8,9,10] Figure 1 shows the fraction of oil and gas components in California that are subject to CARB's regulation, are subject to local air district rules,[11] or handle heavy oil and are exempt from LDAR requirements.[12]

[6] Oil and Gas Methane Regulation, Section 95669(b)(1).
[7] Oil and Gas Methane Regulation, Section 95669(b)(2).
[8] ARB. (2013). Oil and Gas Survey. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.
[9] CAPCOA. (1999). California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities.
[10] 15-Day Notice Attachment 2. https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf.
[11] There are eight local air districts with LDAR requirements for oil and gas facilities, including Bay Area Air Quality Management District (AQMD), Monterey Bay Air Resources District (ARD), San Joaquin Valley Air Pollution Control District (APCD), San Luis Obispo County APCD, Santa Barbara County APCD, South Coast AQMD, Ventura County APCD, and Yolo-Solano AQMD.
[12] Heavy oil is defined differently in different district rules, e.g., by API gravity, by flash point, by vapor pressure, or by evaporation percentage. For the purposes of Figure 1, heavy oil was defined as < 20 API gravity.

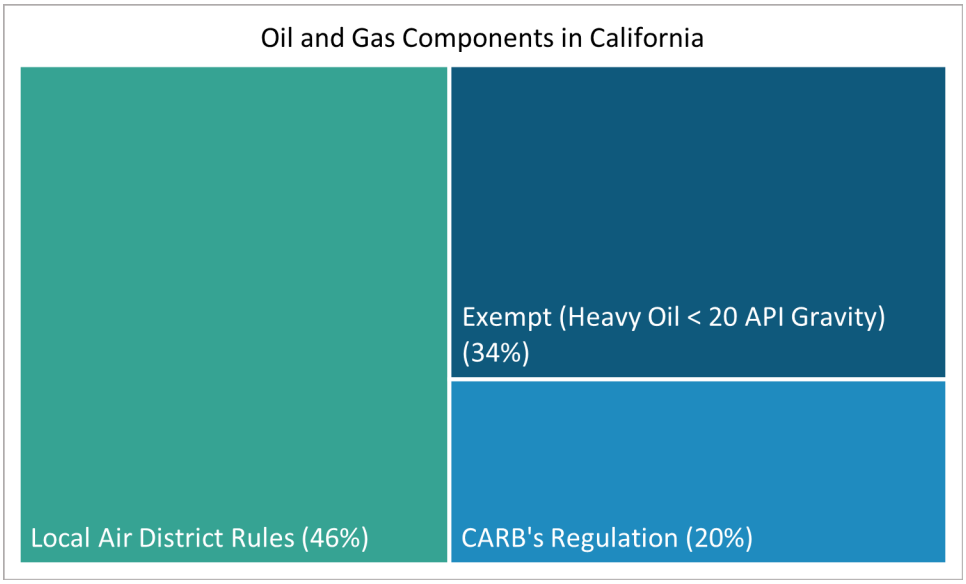

Figure 1: Breakdown of oil and gas components in California. Size of box corresponds to the percent of components in each category (shown in parentheses) based on data from CARB's 2007 oil and gas industry survey and the Oil and Gas Methane Regulation rulemaking.[13,14]

C. Summary of LDAR Data

CARB received 2018 LDAR reports from 69 operators for inspections at 309 facilities. During 2018 LDAR surveys, 1,970,710 unique components were surveyed[15] and 11,359 leaks were identified as greater than or equal to 10,000 ppmv (meaning that the ratio of leaks to components surveyed was 0.58%). Of the leaks found as part of the inspections, 11,288 were repaired or replaced, 37 were critical components[16] and were repaired at the next scheduled shutdown or within 12 months, whichever was sooner, and 34 were delays of repair at the time of reporting and were repaired or replaced within 30 calendar days from the allowed repair time period or by the anticipated repair date stated in the operator's approved delay of repair request. Delays of repairs are requested by operators who need to order specific parts or equipment to repair the leaking component. CARB staff tracks the delay of repair requests to confirm that repairs are completed according to the allowed timeline.[17]

CARB staff reviewed the data in the 2018 annual reports and found no widespread issues with operators' reported data. Issues encountered include conflicting inspection dates, conflicting repair dates, and incorrect initial or repaired leak concentrations. All discrepancies were

[13] ARB. (2013). Oil and Gas Survey. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.
[14] See footnote 10.
[15] Component surveys were repeated quarterly for a total of ~7.8 million component inspections.
[16] A critical component would require the shutdown of a critical process unit if that component was shutdown.
[17] The 71 critical component and delay of repair leaks were included in this report in Tables 1 and 2 and Figures 2 and 3, but not in estimates of emission reductions because those calculations require a concentration after repair.

corrected by CARB staff after following up with operators. During 2018, 0.67% of the reported leaks had potential errors identified that required CARB staff to follow up with operators and make necessary corrections. Of the facilities that reported LDAR data, 7.8% had discrepancies between the number of leaks recorded in the annual LDAR reports' two reporting tables, and 5.2% of all reported quarterly inspections listed incorrect inspection dates (i.e., dates were not in 2018). The validity of the data presented in this report is dependent on the accuracy of the data reported by operators. CARB acknowledges that there are potential limitations with data being self-reported; however, CARB staff conducted rigorous quality control checks to ensure the highest level of data integrity possible. Over time, as operators gain experience with the regulation, CARB staff anticipates a reduction in the prevalence of issues encountered during the first year of reporting.

Table 1 shows the LDAR survey leak distribution for 2018 broken down by oil and gas sector. The allowed leak threshold for 2018 and 2019 was 10,000 ppmv; on January 1, 2020, it decreased to 1,000 ppmv. Natural gas transmission had the largest ratio of leaks to unique components surveyed (2.08%), but the smallest number of components surveyed. Crude oil production had the largest number of components surveyed, but the smallest ratio of leaks to unique components surveyed (0.36%). Figure 2 shows the number of leaks identified in 2018 by component type; connectors and valves had the most leaks of the component types.

Table 1: Components Found Leaking by Sector in 2018

Sector	Total Count of Components in LDAR Program[18]	Number of Leaks in Each Category[19]		Number of Leaks/ Component Count in LDAR Program (%)
		10,000 to 49,999 ppmv	50,000 ppmv or greater	
Crude Oil Production	1,131,913	2,974 (0.26%)	1,077 (0.10%)	0.36%
Natural Gas Production	345,477	2,335 (0.68%)	0 (0%)	0.68%
Natural Gas Storage	392,329	1,940 (0.49%)	931 (0.24%)	0.73%
Natural Gas Transmission	100,991	1,140 (1.13%)	962 (0.95%)	2.08%
Total	1,970,710	8,389 (0.43%)	2,970 (0.15%)	0.58%

[18] These counts include the physical number of components that were surveyed four times throughout the year.
[19] A component could have been found to be leaking during a quarterly inspection and been repaired or replaced within the required time period, but may have been measured as leaking again during a subsequent quarterly inspection, resulting in one component accounting for more than one leak.

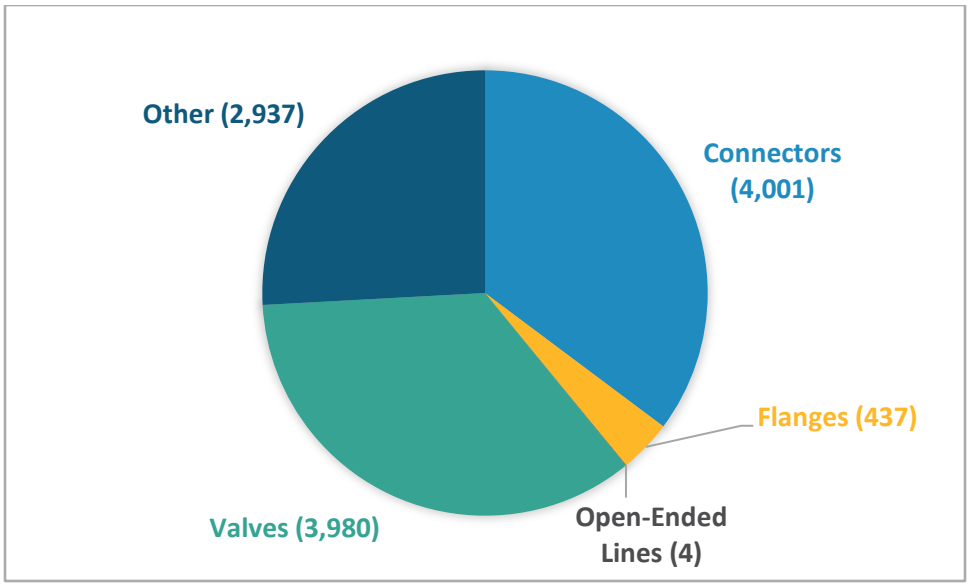

Figure 2: Number of leaks identified in 2018 by component type. The "other" component category includes gas regulators, pressure gauges, pressure relief devices, flow and pressure meter fittings, pneumatic devices, compressor vents, temperature controllers, stuffing boxes, and inactive flare pilots.

CARB staff estimated emissions from the reported leaks using correlation equations developed by Sage.[20] Estimated methane leak rate statistics by component type are shown in Table 2. On average, open-ended lines had the highest leak rates, although they accounted for only four leaks total. The mean leak rate from all components was 0.056 kg CH_4/hr.

Table 2: Methane Leak Rate Statistics by Component Type[21]

	All Components	Connector	Flange	Open-Ended Line	Valve	Other[22]
Min (kg CH_4/hr)	0.008	0.008	0.008	0.093	0.021	0.029
Max (kg CH_4/hr)	1.085	0.178	0.150	0.168	0.864	1.085
Mean (kg CH_4/hr)	0.056	0.020	0.021	0.123	0.070	0.091
Median (kg CH_4/hr)	0.037	0.015	0.018	0.116	0.064	0.096

[20] Air Resources Board IFB No. 13-414: Enhanced Inspection & Maintenance for GHG & VOCs at Upstream Facilities, Sage ATC Environmental Consulting LLC, revised November 2019.
[21] Leak rates were converted from total hydrocarbons assuming a methane composition of 89.2% based on data from the Sage study (see footnote 20).
[22] The max leak rate of 1.085 kg CH_4/hr was on a stuffing box.

Figure 3 shows the cumulative leak emission distribution from 2018, which demonstrates that ~20% of leaks accounted for 50% of estimated emissions from leaking components. This demonstrates that a relatively small number of sources contributed to a significant portion of the emissions, as has been demonstrated in previous studies of oil and gas facilities.[23,24]

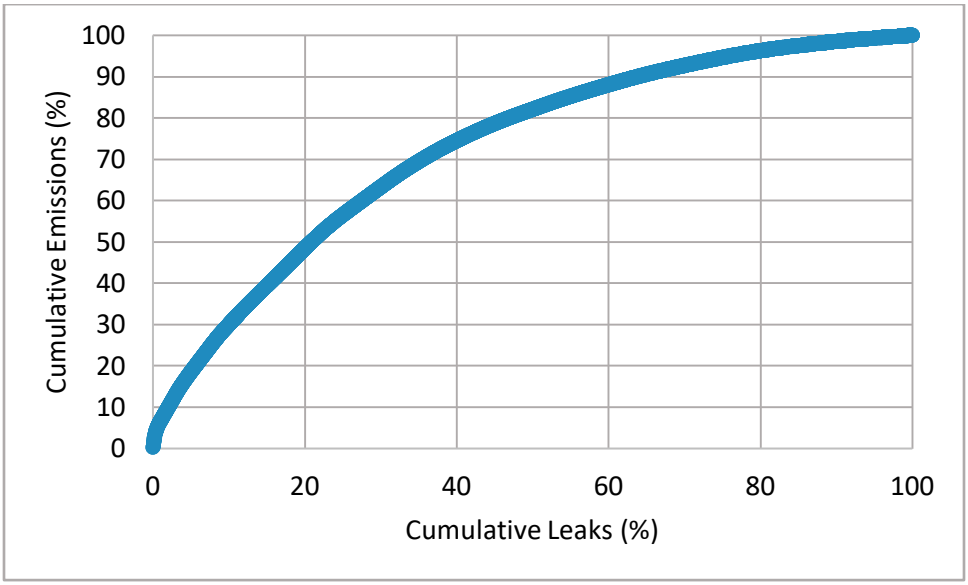

Figure 3: Fraction of cumulative emissions versus cumulative leaks based on LDAR data for 2018.

Emission reductions were estimated by assuming that a leak would have continued unabated for a year without the LDAR program. Total emission reductions from the 2018 LDAR surveys were estimated to be ~5,400 metric tons methane, or ~140,000 metric tons CO_2e.[25] CARB staff also estimated baseline 2018 emissions from all components subject to the regulation in order to evaluate the percent emission reductions from 2018 LDAR surveys. Operators are not required to report concentration data for components measured to be below the leak threshold (10,000 ppmv); therefore, emissions from these "non-leaking" components were estimated by assuming a leak rate equal to the average post-repair leak rate of all leaking components. Similar to emission reductions, baseline emissions from leaks were estimated by assuming that leaks would have persisted for a year without the LDAR program. The combined total baseline emissions from leaking and "non-leaking" components subject to quarterly LDAR surveys for CARB's Oil and Gas Methane Regulation during 2018 was estimated to be ~19,000

[23] Allen, D. (2016). Emissions from oil and gas operations in the United States and their air quality implications. *Journal of the Air & Waste Management Association*, 66:6, 549-575. DOI: 10.1080/10962247.2016.1171263.
[24] Brandt et al. 2016. Methane Leaks from Natural Gas Systems Follow Extreme Distributions. *Environmental Science & Technology*, 50:22, 12512-12520. DOI: 10.1021/acs.est.6b04303.
[25] ~390,000 metric tons CO_2e using the 20-year GWP of methane of 72.

metric tons methane,[26,27] or ~480,000 metric tons CO_2e.[28] Based on those calculations, 2018 LDAR surveys resulted in a 29% reduction in emissions from components subject to the regulation.

Leak data broken down by local air district and owner/operator are shown in Appendix A. Figures A-1 and A-3 show emission reductions from each sector (crude oil production, natural gas production, natural gas transmission, and natural gas storage), and Figures A-2 and A-4 show the ratios of leaks to components surveyed for each sector.[29] San Joaquin Valley Air Pollution Control District (APCD) had the highest emission reductions, with the majority coming from the crude oil production sector (Figure A-1). For all the local air districts with natural gas transmission facilities, the transmission sector had the highest ratios of leaks to components surveyed of the four sectors (Figure A-2). The owner/operator with the highest emission reductions was California Resources Corporation, followed by Pacific Gas and Electric (PG&E) and Southern California Gas Company (SoCalGas) (Figure A-3). The owners/operators with the highest ratios of leaks to components surveyed were SoCalGas, PG&E, and Longbow; similar to the local air district data, natural gas transmission had relatively high leak ratios compared to the other sectors (Figure A-4).

D. Conclusions

The first year of LDAR surveys for CARB's Oil and Gas Methane Regulation was 2018. In total, the ratio of leaks found with concentrations greater than or equal to 10,000 ppmv to the number of unique components surveyed was 0.58%. The natural gas transmission sector had the largest ratio of leaks to components surveyed (2.08%), but the smallest number of components surveyed. The crude oil production sector had the largest number of components surveyed, but the smallest ratio of leaks to components surveyed (0.36%). Leaks were most commonly identified from connectors and valves, while open-ended lines had the highest estimated leak rates on average. Total emission reductions were estimated to be ~5,400 metric tons methane, or ~140,000 metric tons CO_2e.[30] Based on estimates of total emissions from components subject to the regulation (~19,000 metric tons methane), the LDAR surveys resulted in a 29% reduction in emissions for the first year of program implementation.

[26] Converted from total hydrocarbons assuming a methane composition of 89.2% based on data from the Sage study (see footnote 20).
[27] Leaking and "non-leaking" components accounted for ~5,500 and ~13,600 metric tons methane, respectively.
[28] ~1,400,000 metric tons CO_2e using the 20-year GWP of methane of 72.
[29] The ratio metric in this report should not be compared to the "% of total inspected" metric in Tables 1 and 3 of CARB's Oil and Gas Methane Regulation. Tables 1 and 3 pertain to single inspections of a group of components during district or CARB inspections; the ratios in this report represent four inspections of a group of components during operator inspections. The ratio metric also should not be compared to the loss rate used in the Oil Production Greenhouse gas Emissions Estimator (OPGEE).
[30] ~390,000 metric tons CO_2e using the 20-year GWP of methane of 72.

Appendix A: LDAR Data by Local Air District and Owner/Operator

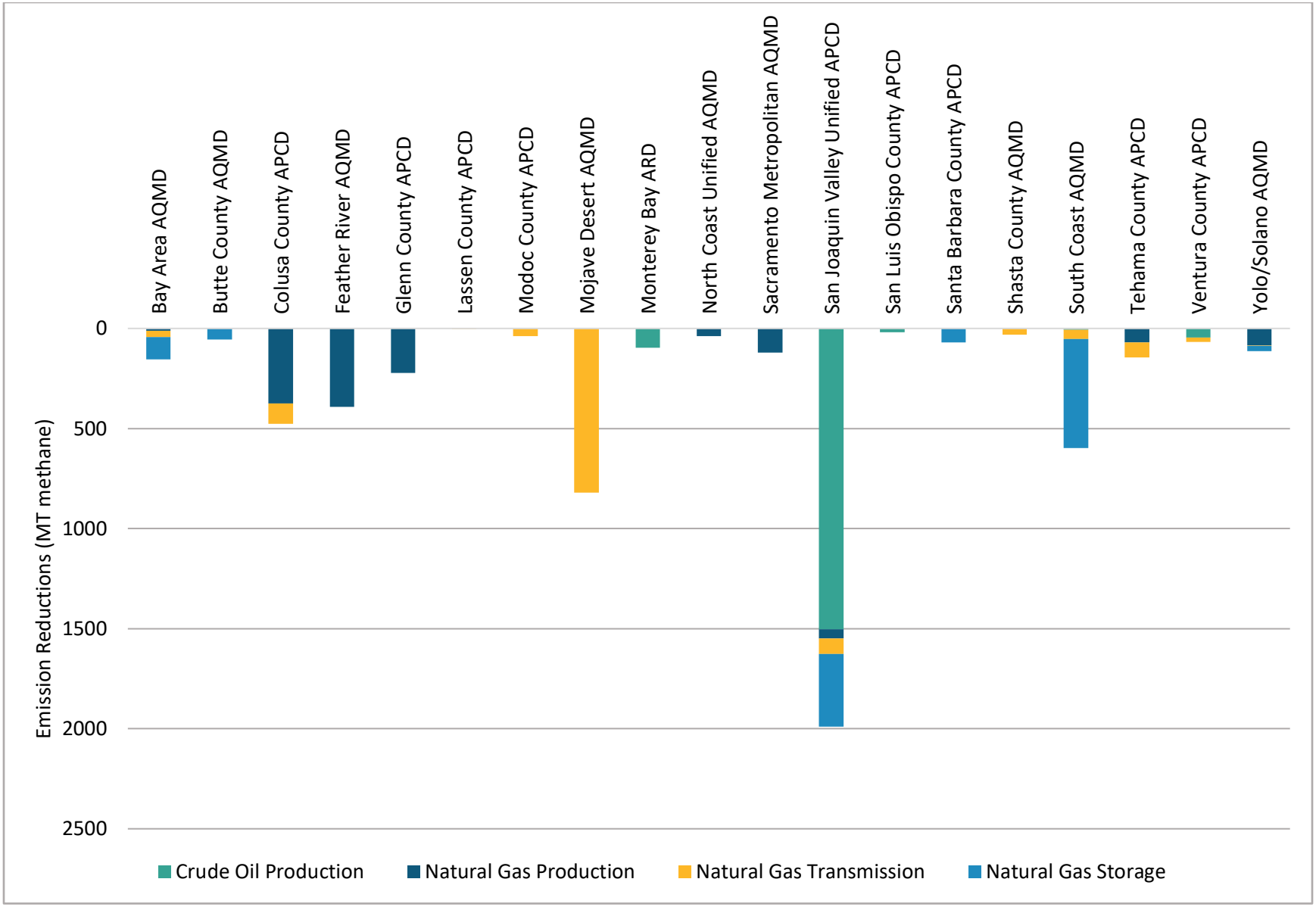

Figure A-1: Emission reductions from each sector by local air district during 2018.

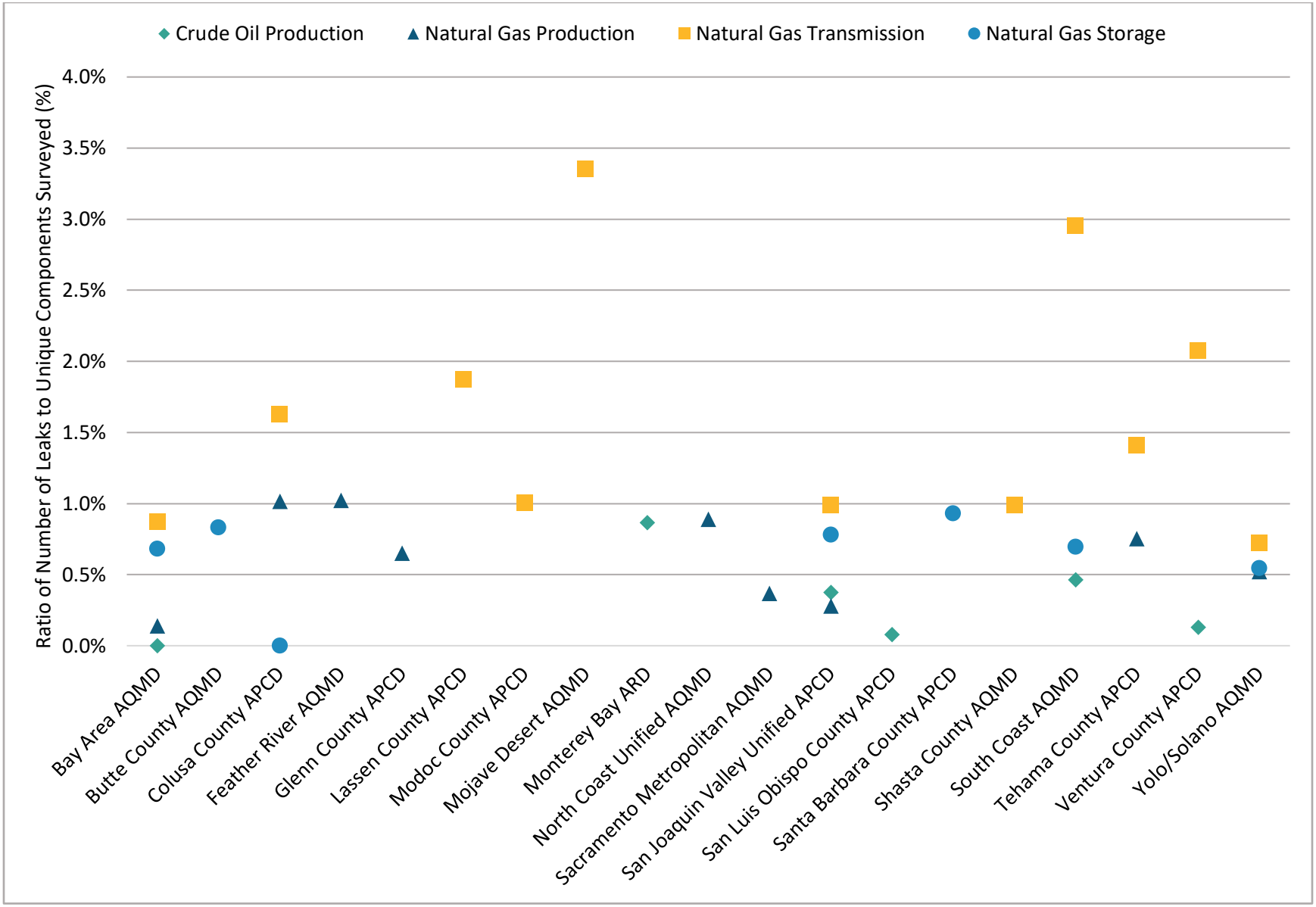

Figure A-2: Ratios of numbers of leaks to numbers of unique components surveyed for each sector by local air district during 2018.

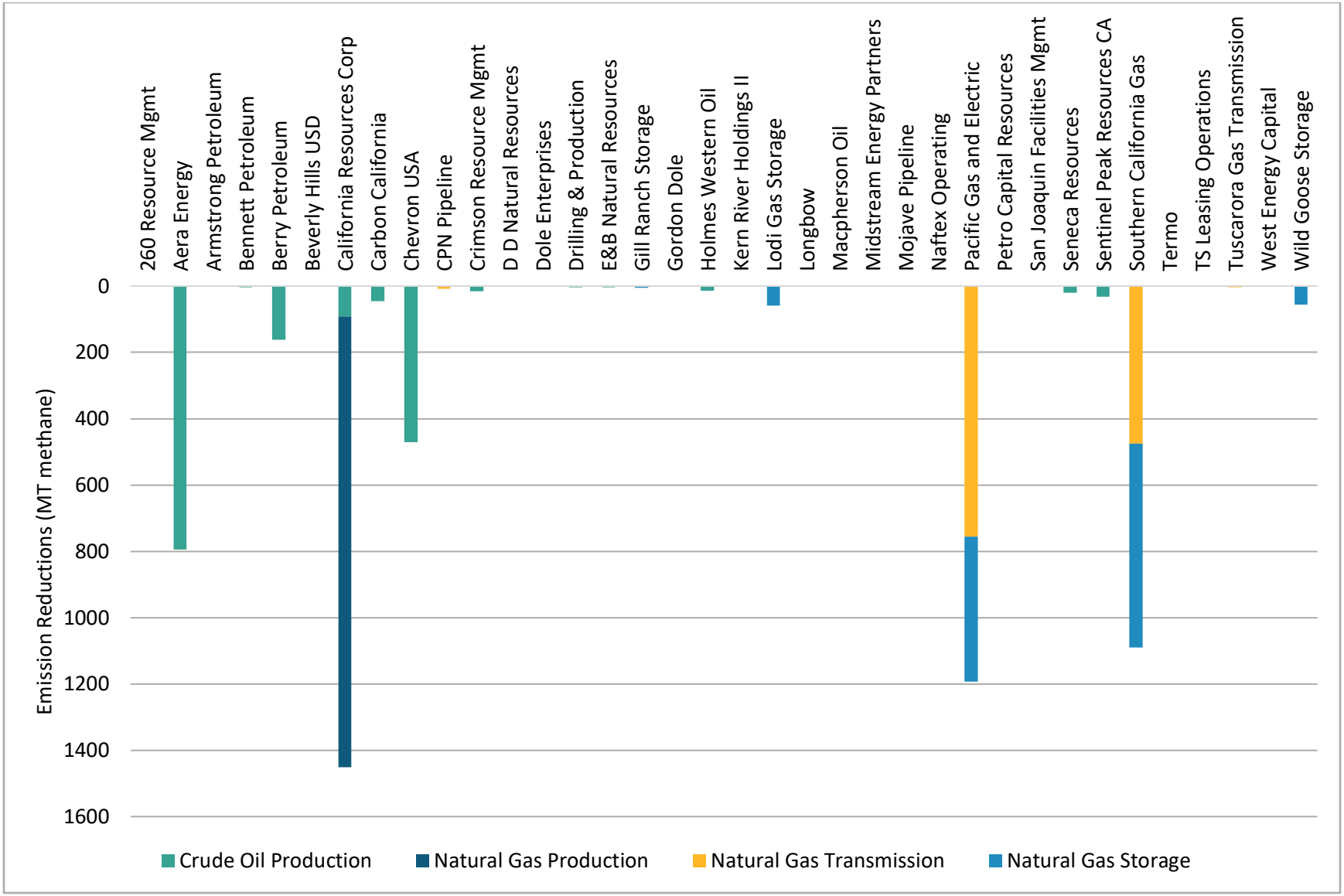

Figure A-3: Emission reductions from each sector by owner/operator during 2018. Of the 69 operators who conducted quarterly LDAR surveys, 33 did not measure any leaks at or above 10,000 ppmv and are therefore not shown here.

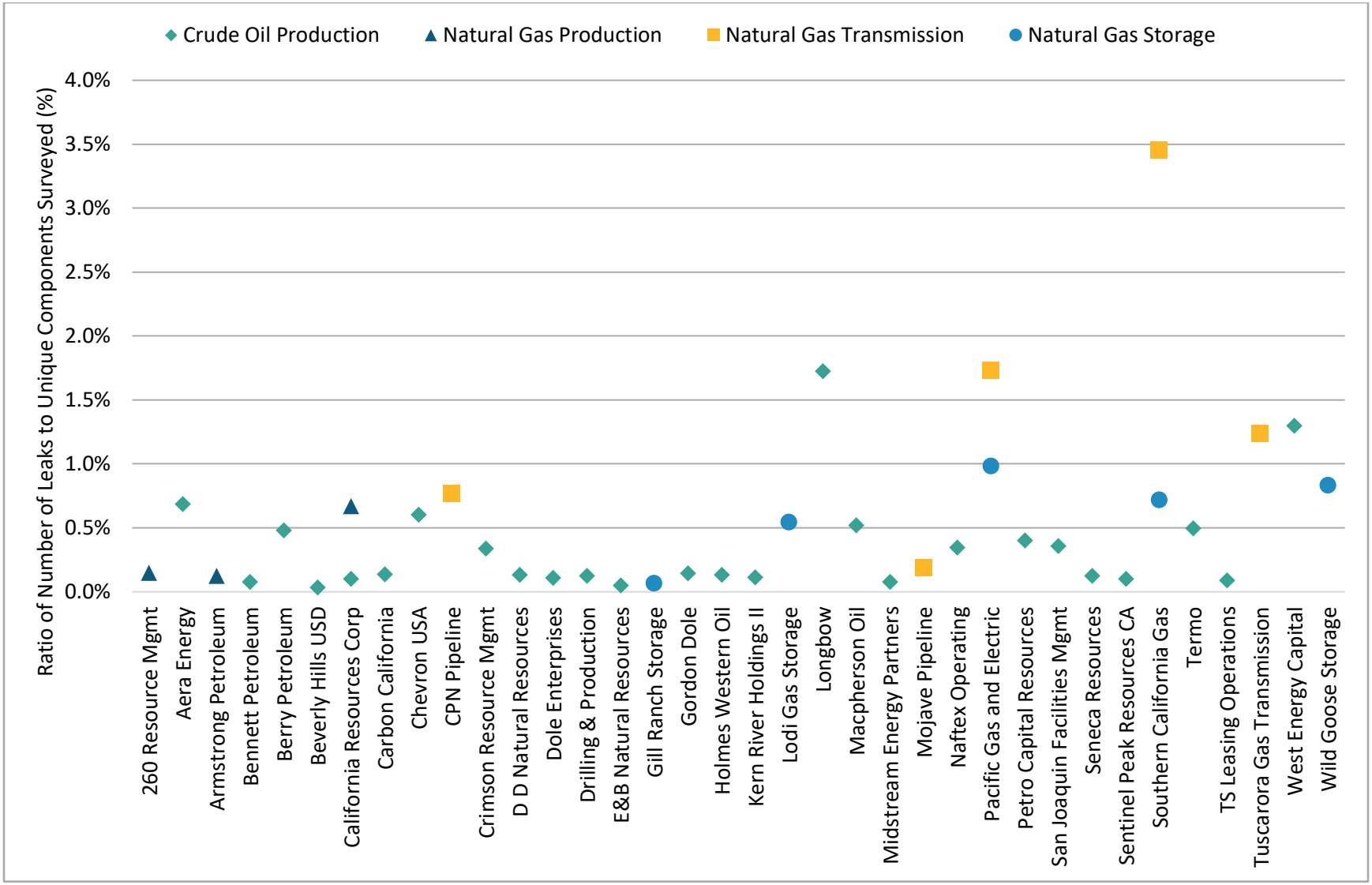

Figure A-4: Ratios of numbers of leaks to numbers of unique components surveyed for each sector by owner/operator during 2018. Of the 69 operators who conducted quarterly LDAR surveys, 33 did not measure any leaks at or above 10,000 ppmv and are therefore not shown here.

Appendix C: Southern Ute Indian Tribe Reservation Air Code

Southern Ute Indian Tribe/State of Colorado Environmental Commission's

Reservation Air Code

Revised: September 15, 2023

Table of Contents

ARTICLE I. GENERAL PROVISIONS

1-101. Declaration of Policy.

The Southern Ute Indian Tribe/State of Colorado Environmental Commission finds and declares that it is the policy of this Commission, in accordance with the charge given this Commission by the Tribe and State in the *Intergovernmental Agreement Between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation*, (1) to protect and improve the air quality on the Reservation, for the benefit of the health and welfare of the residents of the Reservation and the Reservation environment, in a manner that reflects the particular interests of the Tribe and other entities operating on the Reservation, yet remains compatible with State air quality goals; (2) to take into account, in the establishment of the Reservation Air Program, the specific environmental, economic, geographic and cultural needs of the Reservation; and (3) to establish a single comprehensive air quality program applicable to all lands within the exterior boundaries of the Southern Ute Indian Reservation.

1-102. Authority.

This Air Quality Code is adopted pursuant to the authority vested in the Southern Ute Indian Tribe/State of Colorado Environmental Commission by (1) the Intergovernmental Agreement Between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation dated December 13, 1999, (2) tribal law (Resolution of the Council of the Southern Ute Indian Tribe # 00-09), (3) State law (C.R.S. § 24-62-101), and (4) as recognized in federal law (Act of October 18, 2004, Pub. L. No. 108-336, 118 Stat.1354).

1-103. Definitions.

(1) **"Acid rain source"** means an affected unit as defined in regulations promulgated under title IV of the Clean Air Act, namely, a unit that is subject to acid rain emission reduction requirements under title IV of the Clean Air Act.

(2) **"Actual emissions"** means for purposes of calculating emissions fees pursuant to § 2-119 of this code, the amount of emissions, including fugitive emissions from a source that is calculated by using:

(a) The actual rate of emissions in Tons Per Year (TPY) of any fee pollutant emitted from a title V source over the preceding calendar year or any other period determined by the Tribe to be more representative of normal operation and consistent with the fee schedule adopted by the Tribe and approved by the Administrator; and

(b) The unit's actual operating hours, production rates, and in-place control equipment, types of materials processed, stored, or combusted during the preceding calendar year or other period used for this calculation; and

(c) Shall not include emissions of any one fee pollutant in excess of four thousand (4,000) TPY, or any emissions that come from insignificant activities not required in a permit application pursuant to § 2-106(4) of this code.

(3) **"Administrative permit revision"** means a permit revision that:

(a) Corrects typographical errors;

(b) Requires more frequent monitoring or reporting by the permittee;

(c) Indicates a change in ownership or operational control of a source, provided that:

(i) A written agreement, containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee, has been submitted to the Tribe, and the Tribe has determined that no other change in the permit is necessary;

(ii) The new owners have submitted the application information required in § 2-106(4) of this code;

(iii) No grounds exist for permit reopening, revocation and reissuance, or termination, pursuant to § 2-112 of this code; and

(d) Incorporates into the permit the requirements from preconstruction review permits issued pursuant to an EPA approved pre-construction permitting program, provided that the issuance of such preconstruction review permit(s) complies with the procedural and compliance requirements of this code; or

(e) Any other type of change which has been determined by the Tribe and the Administrator to be similar to those in this definition.

(f) Administrative permit amendments for purposes of the acid rain portion of the permit shall be governed by regulations promulgated under title IV of the Act.

(4) **"Administrator"** means the Administrator of the United States Environmental Protection Agency (EPA) or his or her designee.

(5) **"Affected program"** means all tribal, state, and local air pollution control programs:

(a) Whose air quality may be affected and that are contiguous to the Reservation, or

(b) That are within 50 miles of the permitted source.

(6) **"Affected source"** shall have the meaning given to it in the regulations promulgated under title IV of the Act.

(7) **"Air pollutant"** means any air pollution agent or combination of such agents including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant to the extent the Administrator of EPA has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used.

(8) **"Air pollution"** means the presence in the ambient air of one or more air pollutants or combinations thereof in sufficient quantities, which either alone or in connection with other substances, by reason of their concentration and duration, is or tends to be injurious to human, plant or animal life, causes damage to property, unreasonably interferes with the comfortable enjoyment of life or property of a substantial part of a community, obscures visibility, or in any way degrades the quality of the ambient air.

(9) **"Air pollution control equipment"** means any device, equipment, process or combination thereof, the operation of which would limit, capture, reduce, confine, or otherwise control regulated air pollutants, or convert for the purposes of control, any regulated air pollutant to another form, another chemical, or another physical state. This includes, but is not limited to, sulfur recovery units, baghouses, precipitators, scrubbers, cyclones, water sprays, catalytic converters, flares, thermal oxidizers and steam or water injection.

(10) **"Alternative operating scenario (AOS)"** means a scenario authorized in a part 70 permit that involves a change at the part 70 source for a particular emissions unit, and that either results in the unit being subject to one or more applicable requirements which differ from those applicable to the emissions unit prior to implementation of the change or renders inapplicable one or more requirements previously applicable to the emissions unit prior to implementation of the change.

(11) **"Applicable requirement"** means all of the following as they apply to emissions units at a Part 70 source (including requirements that have been promulgated by EPA through rulemaking at the time of permit issuance but that have future compliance dates):

(a) All requirements of this code as they apply to emissions units at a source located within the Reservation boundaries. These include requirements that have been promulgated or approved by the Commission through

rulemaking at the time of permit issuance but that have future compliance dates;

(b) Any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in 40 CFR Part 52;

(c) Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including Parts C or D, of the Act;

(d) Any standard or other requirement under Section 111 of the Act, including Section 111(d);

(e) Any standard or other requirement under Section 112 of the Act, including any requirement concerning accident prevention under Section 112(r)(7) of the Act;

(f) Any standard or other requirement of the acid rain program under title IV of the Act or the regulations promulgated thereunder;

(g) Any requirements established pursuant to Section 504(b) or Section 114(a)(3) of the Act;

(h) Any standard or other requirement under Section 126(a)(1) and (c) of the Act;

(i) Any standard or other requirement governing solid waste incineration, under Section 129 of the Act;

(j) Any standard or other requirement for consumer and commercial products, under Section 183(e) of the Act;

(k) Any standard or other requirement for tank vessels under Section 183(f) of the Act;

(l) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under title VI of the Act, unless the Administrator has determined that such requirements need not be contained in a title V permit; and

(m) Any national ambient air quality standard or increment or visibility requirement under Part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to Section 504(e) of the Act.

(12) **"Approved replicable methodology (ARM)"** means part 70 permit terms that:

(a) Specify a protocol which is consistent with and implements an applicable requirement, or requirement of this code, such that the protocol is based on sound scientific and/or mathematical principles and provides reproducible results using the same inputs; and

(b) Require the results of that protocol to be recorded and used for assuring compliance with such applicable requirement, any other applicable requirement implicated by implementation of the ARM, or requirement of this code, including where an ARM is used for determining applicability of a specific requirement to a particular change.

(13) **"Clean Air Act"** or **"Act"** means 42 U.S.C. § 7401 *et seq*., as amended.

(14) **"Code of Federal Regulations" or "CFR"** means a codification of the general and permanent rules published in the Federal Register by the Executive departments and agencies of the Federal Government.

(15) **"Commission"** means the Southern Ute Indian Tribe/State of Colorado Environmental Commission.

(16) **"Commence Operation"** means, for a new source, when it conducts the activity that it was designed and permitted for (e.g., producing cement or generating electricity).

(17) **"Commission's Procedural Rules"** means the Procedural Rules of the Southern Ute Indian Tribe/State of Colorado Environmental Commission.

(18) **"Compliance plan"** means either a statement that the source will comply with all applicable requirements or, where applicable, a schedule and description of the method or methods for compliance and certification by the owner or operator that the source is in compliance with all applicable requirements.

(19) **"Consumer Price Index"** means for any calendar year, the average of the Consumer Price Index for all-urban consumers, or such revision of the Consumer Price Index for all-urban consumers, or such revisions of the Consumer Price Index that is most consistent with the Consumer Price Index for the most recent calendar year, as published by the U.S. Department of Labor as of the close of 12-month period ending on August 31 of each calendar year.

(20) **"Designated representative"** shall have the meaning given to it in Section 402(26) of the Act and the regulations promulgated thereunder.

(21) **"Deviation"** means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be

determined by observation or through review of data obtained from any testing, monitoring, or recordkeeping established in accordance with § 2-110(5) and (6) of this code. For a situation lasting more than 24 hours which constitutes a deviation, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

(a) A situation where emissions exceed an emission limitation or standard;

(b) A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

(c) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit;

(d) A situation in which an exceedance or an excursion, as defined in 40 CFR Part 64 occurs.

(22) **"Draft Permit"** means a version of an operating permit that the Tribe offers for public participation under § 2-109 of this code and affected program review under § 2-108 of this code.

(23) **"Emergency"** means for purposes of 40 CFR § 70.6(g), any situation arising from sudden and unforeseeable events beyond the control of the permittee including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology–based emission limitation under its permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation or operator error.

(24) **"Emission limitation" and "emission standard"** means a requirement established by the Commission or the Administrator which limits the quantity, rate, concentration, or the visible observations of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emissions reduction, and any design, equipment, work practice or operational standard promulgated under this code or the Clean Air Act.

(25) **"Emissions allowable under the permit"** means:

(a) Any federally enforceable permit term or condition that establishes an emission limitation (including a work practice standard) determined at issuance or renewal to be required by an applicable requirement; or

(b) Any federally enforceable emissions cap that a source has assumed to avoid an applicable requirement to which it otherwise would be subject.

(26) **"Emissions unit"** means any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant or any pollutant listed under Section 112(b) of the Clean Air Act, 42 U.S.C § 7412(b). This term is not meant to alter or affect the definition of the term "unit" for purposes of title IV of the Act.

(27) **"Environmental Protection Agency" or "EPA" or "USEPA"** means the United States Environmental Protection Agency.

(28) **"Excess emissions"** means emissions of an air pollutant in excess of any applicable emission standard.

(29) **"Federally enforceable"** means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60-61, 40 CFR Part 63, requirements within an approved Southern Ute Tribal Implementation Plan, and any permit requirements established pursuant to 40 CFR § 52.21 or under regulations approved pursuant to 40 CFR Part 51, Subpart I, including 40 CFR §§ 50.165 and 51.166.

(30) **"Fee Pollutant"** means any regulated air pollutant as defined in this section except:

(a) Carbon monoxide;

(b) Any pollutant that is a regulated air pollutant solely because it is a Class I or II substance subject to a standard established by or promulgated under title VI of the Clean Air Act;

(c) Any pollutant that is a regulated air pollutant solely because it is subject to a standard or regulation under § 112(r) of the Clean Air Act, 42 U.S.C. § 7412(r); or

(d) Emissions from insignificant activities and insignificant emissions not required to be listed or calculated in a permit application pursuant to § 2-106(4) of this code.

(31) **"Final permit"** means the version of an operating permit issued by the Tribe that has met all requirements of this code.

(32) **"Fugitive emissions"** means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(33) **"General permit"** means a Part 70 permit that meets the requirements of §70.6(d).

(34) **"Hazardous air pollutant"** means a federally listed hazardous air pollutant pursuant to Section 112 of the Clean Air Act.

(35) **"IGA or Intergovernmental Agreement"** means the Intergovernmental Agreement between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation, entered into by the Tribe and State on December 13, 1999.

(36) **"Insignificant activities"** means any of the following types of activities:

(a) Mobile sources;

(b) Air conditioning units used for human comfort that are not subject to applicable requirements under title IV of the Act and do not exhaust air pollutants into the ambient air from any manufacturing or other industrial process;

(c) Ventilating units used for human comfort that do not exhaust air pollutants into the ambient air from any manufacturing or other industrial process;

(d) Heating units used for human comfort that do not provide heat for any manufacturing or other industrial process;

(e) Noncommercial food preparation;

(f) Consumer use of office equipment and products;

(g) Janitorial services and consumer use of janitorial products; and

(h) Internal combustion engines used for landscaping purposes.

(37) **"Insignificant emissions"** means, for regulated air pollutants other than hazardous air pollutants, a potential to emit for any single emissions unit not exceeding 2 tons per year and, for hazardous air pollutants, a potential to emit for any single emissions unit not exceeding 1,000 pounds per year or the de minimis level established under § 112(g) of the Clean Air Act, whichever is less.

(38) **"Major source"** means any stationary source (or any group of stationary sources that are located on one or more continuous or adjacent properties and are under common control of the same person (or persons under common control)) belonging to a single major industrial grouping and that are described in paragraph (a), (b), or (c) of this definition. For the purposes of defining "major source," a stationary source or group of stationary sources shall be considered part

of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within ¼ mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Shared equipment includes, but is not limited to, produced fluids storage tanks, phase separators, natural gas dehydrators or emissions control devices. Surface site, as used in the introductory text of this definition, has the same meaning as in 40 CFR 63.761.

(a) A major source under § 112(a)(1) of the Clean Air Act, 42 U.S.C. § 7412(a)(1), which is defined as:

(i) For pollutants other than radionuclides, any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, 10 TPY or more of any one hazardous air pollutant, 25 TPY or more of any combination of hazardous air pollutants which have been listed pursuant to § 112(b) of the Clean Air Act, 42 U.S.C. § 7412(b), or such lesser quantity as the Administrator may establish by rule. Notwithstanding the preceding sentence, hazardous emissions from any oil or gas exploration or production well (with its associated equipment) and hazardous emissions from any pipeline compressor or pump station shall not be aggregated with hazardous emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources;

(ii) For radionuclides, "major source" shall have the meaning specified by the Administrator by rule.

(b) A major stationary source of air pollutants as defined in § 302 of the Clean Air Act, 42 U.S.C. § 7602, that directly emits, or has the potential to emit, 100 TPY or more of any air pollutant subject to regulation (including any major source of fugitive emissions of any such pollutant, as determined by rule by the Administrator). The fugitive emissions of a stationary source shall not be considered in determining whether it is a major stationary source for the purposes of 302(j) of the Clean Air Act, unless the source belongs to one of the following categories of stationary sources:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum ore reduction plants;
(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or nitric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;

(xviii) Sintering plants;

(xix) Secondary metal production plants;

(xx) Chemical process plants;

(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units (MMBtu) per hour heat input;

(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(xxiii) Taconite ore processing plants;

(xxiv) Glass fiber processing plants;

(xxv) Charcoal production plants;

(xxvi) Fossil fuel-fired steam electric plants of more than 250 MMBtu per hour heat input;

(xxvii) Any other stationary source category, which as of August 7, 1980 is being regulated under Section 111 or 112 of the Act.

(c) A major stationary source as defined in Part D of title I of the Clean Air Act, including:

(i) For ozone nonattainment areas, sources with the potential to emit 100 TPY or more of volatile organic compounds or nitrogen oxides in areas classified as "marginal" or "moderate," 50 TPY or more in areas classified as "serious," 25 TPY or more in areas classified as "severe," and 10 TPY or more in areas classified as "extreme"; provided that the references in this subsection to 100, 50, 25, and 10 TPY of nitrogen oxides shall not apply with respect to any source for which the Administrator has made a finding, under §§ 182(f)(1) or (2) of the Clean Air Act, 42 U.S.C. §§ 7511a(f)(1)-(2), that requirements under § 182(f) of the Clean Air Act do not apply;

(ii) For ozone transport regions established pursuant to § 184 of the Clean Air Act, 42 U.S.C. § 7511c, sources with the potential to emit 50 TPY or more of volatile organic compounds;

(iii) For carbon monoxide nonattainment areas that are classified as "serious," and in which stationary sources contribute significantly to carbon monoxide levels as determined under rules issued by the Administrator, sources with the potential to emit 50 TPY or more of carbon monoxide; and

(iv) For particulate matter (PM-10) nonattainment areas classified as "serious," sources with the potential to emit 70 TPY or more of PM-10.

(39) "Maintenance" means work that is done regularly to keep a machine, building, or piece of air pollution control equipment, process equipment, or process in good condition and working order for continued operation.

(40) "Minor permit revision" means a permit revision that:

(a) Does not violate any applicable requirement;

(b) Does not involve significant permit revisions to existing monitoring, reporting, or recordkeeping requirements in the permit;

(c) Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

(d) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the permittee has assumed to avoid an applicable requirement to which the source would otherwise be subject, including any federally enforceable emissions cap assumed to avoid classification as a modification under title I of the Clean Air Act and any alternative emissions limit approved pursuant to regulations promulgated under § 112(i)(5) of the Clean Air Act, and 42 U.S.C. § 7412(i)(5);

(e) Is not a title I modification; and

(f) Is not required to be processed as a significant permit revision pursuant to § 2-111(4) of this code;

(g) Notwithstanding the criteria listed in paragraphs (a)-(f), a minor permit revision may include permit revisions involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches to the extent that such minor permit revision procedures are provided in the implementation plans or in applicable requirements promulgated by the Administrator.

(41) **"National ambient air quality standard" or "NAAQS"** means the ambient air pollutant concentration limits established by the Administrator pursuant to § 109 (42 U.S.C. § 7409) of the Clean Air Act.

(42) **"Operating permit" and "permit"** (unless the context suggests otherwise) means any permit or group of permits covering a source that is issued, renewed, modified, or revised pursuant to this code, or any permit issued, renewed, amended, revised to a Part 70 source pursuant to 40 CFR Part 70 .

(43) **"Owner or Operator"** means any person who owns, leases, operates, controls, or supervises a stationary source.

(44) **"Part 70 program"** means a program approved by the Administrator under 40 CFR Part 70.

(45) **"Part 70 source"** means all sources subject to 40 CFR Part 70.

(46) **"Permit program costs"** means all reasonable direct and indirect costs related to developing and implementing the operating permit program established under this code, including, but not limited to, costs of the following activities:

(a) Preparing generally applicable regulations or guidance regarding the permit program or its implementation or enforcement;

(b) Reviewing and acting on any application for a permit issuance, revision, or renewal, including the development of applicable requirements as part of the processing of such applications;

(c) General administrative costs of running the operating permit program, including the supporting and tracking of permit applications, compliance certification, and related data entry;

(d) Implementing and enforcing the terms of any operating permit, including adequate resources to determine which sources are subject to the program, but not including any court costs or other costs associated with a court enforcement action;

(e) Emissions and ambient monitoring;

(f) Modeling, analyses, or demonstrations; and

(g) Preparing inventories and tracking emissions.

(47) **"Permit revision"** means a revision to an operating permit that constitutes a significant permit revision, a minor permit revision, or an administrative permit revision, as defined in this code.

(48) **"Permittee"** means the owner, operator, or responsible official at a permitted source, as identified in any permit application or revision.

(49) **"Person"** means any person, public or private corporation, company, partnership, firm, association or society of persons, trust, estate, the United States, or a state and any political subdivision, program, or agency thereof, the Tribe and any department, division, program, enterprise, company, or political subdivision thereof, and any other recognized legal entity.

(50) **"Portable source"** (excluding non-road engines) means any stationary source that is capable of being transported and operated in more than one location. Examples include, but are not limited to, asphalt batch plants and aggregate crushers that commonly and by usual practice are moved from one site to another. A portable source must meet all the permitting requirements for stationary sources. A source will not be considered portable if it remains on one site for more than two years.

(51) **"Potential to emit"** means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is federally enforceable. This term does not alter or affect the use of this term for any other purposes under the Act, or the term "capacity factor" as used in title IV of the Act or the regulations promulgated thereunder.

(52) **"Proposed permit"** means the version of an operating permit that the Tribe proposes to issue and forwards to the Administrator for review in compliance with § 2-108 of this code.

(53) **"Public Law No. 108-336" or " P.L. 108-336"** means the Southern Ute and Colorado Intergovernmental Agreement Implementation Act of 2004 (i.e., Act of October 18, 2004, Pub. L. No. 108-336, 118 Stat.1354), in which Congress provided for the implementation and enforcement of air quality control programs under the Clean Air Act and other air quality programs developed in accordance with the IGA.

(54) **"Regulated air pollutant"** means the following:

(a) Nitrogen oxides or any volatile organic compounds;

(b) Any pollutant for which a national ambient air quality standard has been promulgated;

(c) Any pollutant that is subject to any standard promulgated under § 111 of the Clean Air Act, 42 U.S.C. § 7411;

(d) Any pollutant subject to any standard promulgated or any other requirements established under § 112 of the Clean Air Act, 42 U.S.C. § 7412, including but not limited to the following:

(i) Any pollutant for which the requirements of § 112(g)(2) of the Clean Air Act have been met, but only with respect to the individual source subject to a § 112(g)(2) requirement;

(ii) Any pollutant subject to requirements under § 112(j) of the Clean Air Act, provided that if the Administrator fails to promulgate a standard by the date established pursuant to § 112(e) of the Clean Air Act, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the

applicable date established pursuant to § 112(e) of the Clean Air Act; and

(iii) Any regulated substance subject to requirements under § 112(r) of the Clean Air Act.

(e) Any Class I or II substance subject to any standard promulgated under or established by title VI of the Clean Air Act.

(55) **"Renewal"** means the process by which an operating permit is reissued at the end of its term.

(56) **"Reservation"** means the Southern Ute Indian Reservation.

(57) **"Responsible official"** means one of the following:

(a) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to an operating permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

(ii) The delegation of authority to such representative is approved in advance by the Tribe.

(b) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(c) For a Federal, Tribal, State, Municipal, or other Public Agency: a principal executive officer or ranking elected official. For the purposes of this code, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of the U.S. Environmental Protection Agency).

(d) For an acid rain source: the designated representative (as defined in § 402(26) of the Clean Air Act, 42 U.S.C. § 7651a(26)), and in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned, and for any other purposes under 40 CFR Parts 70 and 71.

(58) **"Schedule of compliance"** means a schedule of remedial measures, including an enforceable sequence of actions or operations, leading to compliance with an applicable implementation plan, emission standard, emission limitation or emission prohibition.

(59) **"Section 502(b)(10) changes"** means changes that contravene an express permit term but that are authorized under § 502(b)(10) of the Clean Air Act, 42 U.S.C. § 7661a(b)(10). Such changes do not include changes that would violate applicable requirements or contravene operating permit terms and conditions that are: monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

(60) **"Shutdown"** means the cessation of operation of any air pollution control equipment, process equipment, or process, for any purpose.

(61) **"Significant permit revision"** means:

(a) Any revision to an operating permit that does not meet the definitions for an administrative permit revision or a minor permit revision;

(b) Any revision that would result in any significant change to existing monitoring permit terms or conditions and any relaxation to existing recordkeeping, or permit reporting terms or conditions;

(c) Any revision for which action on the application would, in the judgment of the Tribe, require decisions to be made on significant or complex issues;

(d) Any revision that would be required if the existing operating permit specifically prohibits the proposed change; and

(e) Changes in ownership that do not meet the criteria for Section (c) of the definition of an administrative permit revision.

(62) **"Similar sources"** means sources that are generally similar in terms of operations, processes, and emissions, subject to the same or substantially similar requirements, and not subject to case-by-case standards or requirements.

(63) **"Startup"** means the setting into operation of any air pollution control equipment, process equipment, or process, for any purpose.

(64) **"Stationary Source"** or **"Source"** means any building, structure, facility, or installation that emits or may emit any regulated air pollutant or any pollutant listed under Section 112(b) of the Act except those emissions resulting directly

from an internal combustion engine for transportation purposes or from a nonroad engine or nonroad vehicle as defined in § 216 of the Clean Air Act.

(65) **"Subject to regulation"** means, for any air pollutant, that the pollutant is subject to either a provision in the Clean Air Act, or a nationally-applicable regulation codified by the Administrator in subchapter C of chapter I of Code of Federal Regulations Title 40 (i.e., 40 C.F.R. Part 70), that requires actual control of the quantity of emissions of that pollutant, and that such a control requirement has taken effect and is operative to control, limit or restrict the quantity of emissions of that pollutant released from the regulated activity. Except that:

(a) *Greenhouse gases (GHGs),* the air pollutant defined in 40 C.F.R. § 86.1818–12(a) as the aggregate group of six greenhouse gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, shall not be subject to regulation unless, as of July 1, 2011, the GHG emissions are at a stationary source emitting or having the potential to emit 100,000 tpy CO_2 equivalent emissions.

(b) The term *tpy CO_2 equivalent emissions (CO_2 e)* shall represent an amount of GHGs emitted, and shall be computed by multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A–1 to subpart A of part 98 of chapter I of Code of Federal Regulations Title 40 (i.e., 40 C.F.R. 98 (Table A-1)) —Global Warming Potentials, and summing the resultant value for each to compute a tpy CO_2e.

(66) **"Temporary source"** (excluding non-road engines) means any source that is situated in one location for less than one year, after which it will be dismantled and removed from the site. Any temporary source located at one location for longer than one year will be deemed a stationary source and must meet the requirements for stationary source permitting in this code.

(67) **"Tribe"** means the Southern Ute Indian Tribe, which is the permitting authority.

(68) **"Unit"** means a fossil fuel-fired combustion device, for purposes of title IV of the Act.

(69) **"Volatile Organic Compounds"** means the same as that term is defined by the Administrator at 40 CFR Part 51.

1-104. Administration.

Pursuant to the authorities cited above, the Southern Ute Indian Tribe is responsible for the administration, implementation and enforcement of this code, subject to the Commission's review of appealable administrative actions by the Tribe.

1-105. Investigations and Information Requests.

(1) For the purpose (i) of developing or assisting in the development of any implementation plan, any standard of performance, or any emission standard, (ii) of determining whether any person is in violation of any such standard or any requirement of such a plan, or (iii) carrying out any provision of this Code –

(a) The Tribe may require any person, on a one-time, periodic or continuous basis, who owns or operates any emission source, who the Tribe believes may have information related to the purposes set forth in this Code, or who is subject to any requirement of this Code to—

(i) Establish and maintain records and reports; install, use, and maintain monitoring equipment; use audit procedures or methods; keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical, as determined by the Tribe;

(ii) Sample emissions (in accordance with such procedures or methods, at such locations, at such intervals, during such periods and in such manner as the Tribe shall prescribe);

(iii) Submit compliance certifications in accordance with subsection (3) of this section; and

(iv) Provide such other information as the Tribe may reasonably require relating to emissions of the source or to any investigation authorized by this Code;

(b) The Tribe, through its authorized representatives, upon presentation of credentials, has the power to enter and inspect any property, premises, or place for the purpose of investigating any actual, suspected, or potential source of air pollution or ascertaining compliance with any requirement of this Code or any order or permit, or term or condition thereof, issued or promulgated pursuant to this Code; and the Tribe may, at reasonable times, have access to and copy any record, inspect any monitoring equipment or method, or sample any emissions required pursuant to this Code. Any information relating to secret processes or methods of manufacture or production obtained in the course of the inspection or investigation may be kept confidential in accordance with 2-124; except that emission data shall not be withheld from the Tribe as confidential. The Tribe shall promptly furnish a duplicate of any analytical report or observation of an air pollutant to the person who is suspected of causing such air pollution.

(c) The Tribe shall in the case of any person who is the owner or operator of a major stationary source, and may, in the case of any other person, require enhanced monitoring and submission of compliance certifications. Compliance certifications shall include (A) identification of the applicable requirement that is the basis of the certification, (B) the method used for determining the compliance status of the source, (C) the compliance status, (D) whether compliance is continuous or intermittent, and (E) such other facts as the Tribe may require. Submission of a compliance certification shall in no way limit the Tribe's authorities to investigate or otherwise implement this Code.

1-106. Air Pollution Emergencies Endangering Public Health or Welfare on the Reservation.

(1) Whenever the Tribe determines, after investigation, that any person is either engaging in any activity involving a significant risk of air pollution or is discharging or causing to be discharged into the atmosphere, directly or indirectly, any air pollutants and such activity or discharge either (1) constitutes a clear, present, and immediate danger to the environment or to the health of the public, or that any such activity or discharge of air pollutants, if permitted to continue unabated, will result in a condition of clear, present, and immediate danger to the health of the public, or (2) does not constitute a clear, present, and immediate danger to the health of the public, but is of such a nature as to cause extreme discomfort or that it is an immediate danger to the welfare of the public because such pollutants make habitation of residences or the conduct of businesses subjected to the pollutants extremely unhealthy or disruptive, the Tribe shall:

(a) Issue a written cease-and-desist order to said person requiring immediate discontinuance of such activity or the discharge of such pollutant into the atmosphere, and, upon receipt of such order, such person shall immediately discontinue such activity or discharge; or

(b) Apply to the United States District Court for the District of Colorado, in accordance with the IGA and Public Law No. 108-336, for a temporary restraining order, temporary injunction, or permanent injunction as provided for in the federal rules of civil procedure; or

(c) Both issue such a cease-and-desist order and apply for any such restraining order or injunction.

(2) **Other Incidental Powers.** The Tribe may exercise all incidental powers necessary to carry out the purposes of this Code.

1-107. Enforcement.

In accordance with the IGA and Public Law No. 108-336, the Tribe and Commission shall enforce compliance with this Code including, if necessary, through a civil action for declaratory or injunctive relief, or for other orders in aid of enforcement, in the United States District Court for the District of Colorado. Appealable administrative actions taken by the Tribe shall be subject to review in accordance with the adjudicatory procedures contained in the Commission's Procedural Rules.

1-108. Severability and Preservation of Rights.

(1) **Severability.** If any provision of this code, or the application of any provision of this code to any person or circumstance, is held invalid, the remainder of this code and the application of such provision to other persons or circumstances shall remain unaffected.

(2) **Preservation of rights.** It is the purpose of this code to provide additional and cumulative remedies to prevent, abate, and control air pollution on the Southern Ute Indian Reservation. Nothing contained in this code shall be construed to abridge or alter rights of action or remedies in equity under the common law or statutory law, nor shall any provisions of this part or any act done by virtue thereof be construed as preventing the Tribe, Commission, or individuals from the exercise of their rights under the common law or statutory law to suppress nuisances or to abate pollution, provided however, no action shall be inconsistent with the CAA and this code.

ARTICLE II. AIR QUALITY CONTROL PROGRAMS

PART 1. TITLE V OPERATING PERMIT PROGRAM

2-101. Program Overview.

The purpose of this part is to establish an air quality permitting program consistent with the requirements of title V of the Clean Air Act (42 U.S.C. 7661-7661f *et. seq.*), its implementing regulations at 40 CFR Part 70, and regulations applicable to treatment of Indian Tribes in the same manner as States for purposes of tribal administration of Clean Air Act programs (40 CFR Part 49).

2-102. Effective Date.

This title V Operating Permit Program shall become effective upon the date of the approval by the Administrator of the Tribe's application for treatment as a state and Part 70 program approval.

2-103. Permit Program Definitions.

Except as specifically provided in this section, terms used in this part retain the meaning accorded them under the applicable requirements of the Clean Air Act (42 U.S.C. § 7401 *et seq.*) and its implementing regulations.

2-104. Applicability.

(1) Permit Required. Except as provided in subsection 2 below, the following facilities are required to obtain an operating permit under this section:

(a) Any major source;

(b) Any source, including an area source, subject to a standard, limitation, or other requirement under Section 111 of the Clean Air Act, except all sources and source categories that would be required to obtain a permit solely because they are subject to Part 60, subpart AAA - Standards of Performance for New Residential Wood Heaters; and all sources and source categories that would be required to obtain a permit solely because they are subject to Part 61, subpart M – National Emission Standards for Hazardous Air Pollutants for asbestos, § 61.145, Standard for Demolition and Renovation;

(c) Facilities with a source subject to 40 CFR Part 63 or any other standard or other requirement under Section 112 of the Federal Clean Air Act, except that a source is not required to obtain a permit solely because it is subject to rules or requirements under Section 112(r) of the Clean Air Act;

(d) Any acid rain source; or

(e) Facilities in a source category designated by EPA as subject to the requirements of 40 CFR Part 70.

(2) Exemptions.

(a) The following sources are exempted from the requirement to obtain an operating permit:

(i) All sources listed in this code that are not major sources, acid rain sources, or solid waste incineration units required to obtain a permit pursuant to Section 129(e) of the Clean Air Act, may be exempted by the Tribe from the obligation to obtain a Part 70 permit until such time as the Administrator completes a rulemaking to determine how the program should be structured for non-major sources and the appropriateness of any permanent exemptions in addition to those provided for in paragraph (1)(b) of this section.

(ii) In the case of non-major sources subject to a standard or other requirement under either Section 111 or Section 112 of the Clean Air Act after July 21, 1992 publication, the Administrator will determine whether to exempt any or all such applicable sources from the requirement to obtain a Part 70 permit at the time that the new standard is promulgated.

(b) No Part 70 source may operate after the effective date of this code without a valid permit issued under this code unless:

(i) The Part 70 source has submitted a timely and complete application for permit issuance or renewal consistent with § 2-106 of this code; or

(ii) The Tribe fails to issue or disapprove a renewal permit before the end of the prior permit term, in which case, that permit shall not expire and all its terms and conditions shall remain in effect until the renewal permit has been issued or disapproved.

(3) Cease of Operations. The ability to operate under this section shall cease if (1) the Tribe takes final action to deny the applicant a permit or (2) the applicant fails to submit by the deadline specified in writing by the Tribe any additional information identified as being needed to process the application.

2-105. Certification.

Any application, form, report, compliance certification, or other document submitted by the applicant or permittee pursuant to this code shall contain a certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under this code shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

2-106. Permit Applications.

(1) Duty to Apply. For each Part 70 source, the owner or operator shall submit to the Tribe a timely and complete permit application in accordance with this code.

(2) Timely Application. Consistent with 40 CFR 70.5(a)(1), a timely application for a source applying for an operating permit is:

(a) For Part 70 sources that commence operation after Part 70 program approval by USEPA Region VIII, one that is submitted within one year after the source commences operation as a Part 70 source;

(b) For renewal applications, one that is submitted at least 6 months but not more than 18 months before the date of permit expiration;

(c) For a source subject to the requirements of § 112(g) of the Clean Air Act or required to have a permit under the preconstruction review program under Part C or D of title I of the Act after Part 70 program approval by USEPA Region VIII, one that is submitted within one year of commencing operation. Where an existing part 70 permit would prohibit such construction or change in operation, the source must obtain a permit revision before commencing operation;

(d) The permittee shall notify the Tribe of an initial or revised New Source Review (NSR) permit, that is not issued by the Tribe, within thirty (30) calendar days of the effective date of that permit. The requirements of the NSR permit shall be incorporated into the operating permit according to the administrative permit revision process in RAC § 2-111(2) unless additional applicable requirements are triggered by the change in which case a permit revision application must be submitted according to the minor permit revision process in RAC § 2-111(3) or the significant permit revision process in RAC § 2-111(4). Permit applications are to be submitted according to the timelines established in RAC § 2-106(2).

(3) Complete Application.

(a) To be determined complete, an application must provide all information required pursuant to this code, except that an application for permit revision need supply only such information as is related to the proposed change.

(b) A source's ability to operate without a permit pursuant to this code shall be in effect from the date a timely application is submitted until final action is taken on the application, provided that the application is determined to be complete under this code and the applicant adequately submits any requested additional information by deadlines specified by the Tribe.

(c) The submittal of a complete application shall not affect the requirement that any source have a preconstruction permit under title I of the Act.

(4) Application Content. All applications shall be made on the most current forms provided by the Tribe and according to the instructions provided by the Tribe, and shall include the following information:

(a) The date of the application;

(b) The applicant's name and address (and, if different, plant name and address); the names and addresses of the owner(s), the responsible official(s), and the operator(s) of the source; any subsidiaries or parent companies; the company's state of incorporation or principal registration to do business; and the names and telephone numbers of the owners' agent(s) and the plant site manager/contact;

(c) The exact location of the source identified by latitude and longitude, or by UTM coordinates, and legal description that includes Township – Section – Range and is shown on a map, such as the 7.5 minute Topographic Quadrangle map published by the United States Geological Survey or the most detailed map available;

(d) A description of the source's processes and products (by Standard Industrial Classification Code), including any associated with alternative scenarios identified by the applicant;

(e) The following emissions-related information, including all calculations and computations on which such information is based:

(i) All emissions of regulated air pollutants for which the source is major and all emissions of regulated air pollutants, including fugitive emissions for the source and for each emissions unit;

(ii) A process flow sheet of all components of the facility that would be involved in routine operations and emissions;

(iii) Identification and description of all emissions points in sufficient detail to establish the basis for fees and applicability of requirements of this code;

(iv) Emissions rates in tons per year (TPY) and in such terms as are necessary to establish compliance consistent with the applicable standard reference test method. For emissions units subject to an annual emissions cap, TPY can be reported as part of the aggregate emissions associated with the cap, except where more specific information is needed, including where necessary to determine and/or assure compliance with an applicable requirement;

(v) Specific information such as that regarding fuels, fuel use, raw materials, or production rates, to the extent needed to determine or regulate emissions;

(vi) Identification and full description of all air pollution control equipment and compliance monitoring devices or activities;

(vii) The maximum and standard operating schedules of the source, and any work practice standards or limitations on source operation which affect emissions of regulated air pollutants;

(viii) An operational plan defining the measures to be taken to mitigate source emissions during startups, maintenance, shutdowns, and emergencies;

(ix) Other relevant information as the Tribe may reasonably require or which are required by any applicable requirements;

(x) Additional information related to the emissions of air pollutants to verify which requirements are applicable to the source; and

(xi) For each reasonably anticipated alternative operating scenario identified by the applicant, all of the information required in paragraphs (i) through (x) above, as well as additional information determined to be necessary by the Tribe to define such alternative operating scenarios identified by the source pursuant to this code;

(f) For insignificant activities which are exempted because of size or production rate, a list of insignificant activities at the source and any information necessary to determine applicable air pollution control requirements and, for insignificant emissions, a listing of such emissions in sufficient detail to identify the emission unit and indicate that the exemption applies. Similar emission units, including similar capacities or sizes, may be listed under a single description. No additional information

is required at the time of application, but the Tribe may request additional information during application processing;

(g) The following information concerning applicable air pollution control requirements:

(i) Citation and description of all applicable requirements,

(ii) Description of or reference to any applicable test method for determining compliance with each applicable requirement, and

(h) Explanation of any proposed exemptions from otherwise applicable requirements.

(i) Other specific information that may be necessary to implement and enforce other applicable requirements of this code or the Clean Air Act or to determine the applicability of such requirements, including information necessary to collect any fees owed under this code;

(j) Additional information as determined to be necessary by the Tribe to define proposed AOSs identified by the source pursuant to § 2-110(8)(b) of this code or to define permit terms and conditions implementing any AOS under § 2-110(8)(b) or implementing § 2-116 or § 2-110(8)(c) of this code. The permit application shall include documentation demonstrating that the source has obtained all authorization(s) required under the applicable requirements relevant to any proposed AOSs, or a certification that the source has submitted all relevant materials to the appropriate permitting authority for obtaining such authorization(s);

(k) Compliance certification by a responsible official consistent with this code including:

(i) A certification of the source's compliance status for each applicable requirement;

(ii) A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods;

(iii) A schedule for submission of compliance certifications during the permit term, to be submitted no less frequently than annually; and

(iv) A statement indicating the source's compliance status with any applicable monitoring and compliance certification requirements of the Clean Air Act;

(l) A compliance plan and schedule that contain:

(i) A description of the compliance status of the source with respect to all applicable requirements;

(ii) For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements, and for requirements for which the source is not in compliance at the time of permit issuance, a narrative description of how the source will achieve compliance with such requirements;

(iii) For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis;

(iv) A compliance schedule for sources that are not in compliance with all applicable requirements at the time of permit issuance, including a remedial measures schedule, with an enforceable sequence of actions with milestones, leading to compliance with such applicable requirements, provided that the compliance schedule shall be at least as stringent as that contained in any consent decree or administrative order to which the source is subject, and the obligations of any consent decree or administrative order shall not be in any way diminished by the compliance schedule, and that any such compliance schedule shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based; and

(v) A schedule for submission of certified progress reports no less frequently than every 6 months for sources required to have a schedule of compliance to remedy a violation.

(vi) The compliance plan content requirements specified in this paragraph shall apply and be included in the acid rain portion of a compliance plan for an affected source, except as specifically superseded by regulations promulgated under title IV of the Act with regard to the schedule and method(s) the source will use to achieve compliance with the acid rain emissions limitations.

(vii) For applicable requirements that will become effective upon implementation of an AOS, a statement that the source will meet such requirements upon implementation of an AOS.

(5) Duty to Supplement and Correct. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application

or in a supplemental submittal shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide further information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft permit.

2-107. Action on Permit Applications

(1) Completeness Determinations.

(a) Within 60 days of receiving an application for a permit, significant revision, or renewal, the Tribe shall determine whether the application is complete or incomplete under §2-106 of this code. Within 30 days of receiving an application for a minor permit revision, the Tribe shall determine whether the application is complete or incomplete under §2-106 of this code. The Tribe shall promptly notify the applicant of its completeness or incompleteness determination by electronic mail with delivery and read receipts. An incompleteness notice shall also state what additional information or points of clarification are necessary for the application to be determined complete and shall provide a deadline for the applicant to respond to the incompleteness notice. If the Tribe has issued an incompleteness determination and requested additional information, the deadline for making a completeness or incompleteness determination shall be no later than 60 days after receipt of the additional information submitted in support of a permit, significant revision, or renewal, and 30 days for information supporting a minor permit revision.

(b) For an initial permit, renewal permit or significant permit revision, if the Tribe does not request additional information or otherwise notify the applicant of incompleteness within 60 days of receiving an application or requested additional information, the application shall be deemed complete.

(c) For a minor permit revision, if the Tribe does not request additional information or otherwise notify the applicant of incompleteness within 30 days of receipt an application or requested additional information, the application shall be deemed complete.

(2) Federal Review. The Tribe shall submit a copy of the permit application, draft permit, statement of basis, and final permit to the Administrator for review.

(3) Statement of Basis. The Tribe shall prepare a statement of basis for every draft permit subject to this section. The statement of basis shall briefly describe the legal and factual basis for the draft permit conditions (including references to the applicable statutory or regulatory provisions) or, in the case of notices of intent to deny or terminate, reasons supporting the initial decision. The statement of basis

shall be sent to the applicant, Administrator, and to any other person who requests it.

(4) Final Action. The Tribe shall take final action on all permit applications as specified in the paragraphs below:

(a) For applications for permits authorizing early reductions and/or alternative emissions limitations consistent with § 112(i)(5) of the Clean Air Act, 42 U.S.C. § 7412(i)(5), the Tribe shall take final action on applications within 9 months of receipt of the complete application;

(b) For initial and renewal permits, the Tribe shall take final action within 18 months after an application is determined or deemed complete.

(c) For administrative permit revisions, the Tribe shall take final action within 60 days upon receipt of the complete revision request, including any supplemental information requested by the Tribe.

(d) For minor permit revisions, the Tribe shall take final action within 90 days after the application is determined or deemed complete.

(e) For significant permit revisions, the Tribe shall take final action within 9 months after the application is determined or deemed complete.

(5) Issuance. A permit, permit revision, or permit renewal shall only be issued if all of the following conditions have been met:

(a) The Tribe has received a complete application;

(b) Except for administrative permit revisions, the Tribe has complied with the requirements for notifying and responding to affected programs under § 2-108 of this code;

(c) Except for administrative and minor permit revisions, the Tribe has complied with the requirements for public participation procedures under § 2-109 of this code;

(d) The conditions of the permit provide for compliance with all applicable requirements including the requirements of this code; and

(e) The Administrator has received a copy of the proposed permit and any notices required under this code, and has not objected to issuance of the permit within the time period allowed.

(6) Decision and Notification.

(a) The Tribe shall grant or disapprove the permit, permit revision, or permit renewal, based on information contained in the Tribe's administrative record.

(b) The administrative record for any final permit shall consist of:

(i) All comments received during any public comment period, including any extension or reopening;

(ii) The tape or transcript of any hearing(s) held;

(iii) Any written material submitted at such a hearing;

(iv) The response to comments and any new materials placed in the record;

(v) Other documents contained in the supporting file for the permit;

(vi) The final permit;

(vii) The application and any supporting data furnished by the applicant;

(viii) The draft permit or notice of intent to deny the application or to terminate the permit;

(ix) The statement of basis for the draft permit;

(x) All documents cited in the statement of basis;

(xi) Other documents contained in the supporting file for the draft permit.

(c) The additional documents required under paragraph (b) of this section should be added to the record as soon as possible after their receipt or publication by the Tribe. The record shall be complete on the date the final permit is issued.

(d) Material readily available at the Tribe, or published materials which are generally available and which are included in the administrative record under the standards of § 2-109(6) of this code need not be physically included in the same file as the rest of the record as long as it is specifically referred to in the statement of basis or in the response to comments.

(e) If the Tribe disapproves a permit, permit revision, or permit renewal, the Tribe shall notify the applicant by electronic mail with delivery and read receipts of the action taken and the reasons therefor. If the Tribe grants a permit, permit revision, or permit renewal, the Tribe shall mail the permit, permit revision, or permit renewal, including all terms and conditions, to the applicant by electronic mail with delivery and read receipts.

(7) Renewal and Expiration.

(a) Permits being renewed are subject to the same procedures, including those for public participation and affected program and EPA review, as those that apply to initial permit issuance.

(b) Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with § 2-104(2)(b) and § 2-106 of this code.

(c) If the Tribe fails to act in a timely way on a permit renewal, EPA may invoke its authority under Section 505(e) of the Act to terminate or revoke and reissue the permit.

(8) Non-action. No permit, revision, or renewal shall be issued by failure of the Tribe to act on an application.

(9) Prioritization of Certain Applications. Where reasonably possible, the Tribe shall give priority to taking action on applications for construction or modification under title I, parts C and D of the Act.

2-108. Review by the Administrator and Affected Programs.

(1) Applicability. The Tribe shall not issue any final operating permit, revision, or renewal for any source until the Administrator has had an opportunity to review the proposed permit as required under this section. Permits for source categories waived by the Administrator from this requirement and any permit terms or conditions which are not required under the Clean Air Act or under any of its applicable requirements are not subject to Administrator review or approval.

(2) Transmittal.

(a) Within 5 days after an application has been deemed complete, the Tribe shall transmit a copy of the complete permit application (including the compliance plan and all additional materials submitted by the applicant) directly to the Administrator. To the extent practicable, the preceding information shall be provided in a computer readable format compatible with the Administrator’s national database management system. The Tribe shall also provide to the Administrator a copy of each draft permit,

each statement of basis, each proposed permit, each final operating permit, and any other relevant information requested by the Administrator.

(b) The Tribe shall provide notice of each draft permit under this section to every affected program on or before the time that the Tribe provides such notice to the public under § 2-109 of this code, except to the extent that minor permit revision procedures authorize different notice procedures.

(c) The Tribe, as part of the submittal of a proposed permit to the Administrator (or as soon as possible after the submittal for minor permit revision procedures under § 2-111(3) of this code), shall notify the Administrator and any affected program in writing of any refusal by the Tribe to accept all recommendations for the proposed permit that the affected program submitted during the public or affected program review period. The notice shall include the Tribe's reasons for not accepting any such recommendation. The Tribe is not required to accept recommendations that are not based on federally enforceable applicable requirements or this code.

(d) The Tribe shall keep for 5 years such records and submit to the Administrator such information as the Administrator may reasonably require to ascertain whether this program complies with the requirements of the Clean Air Act, 40 CFR Part 70, or related applicable requirements.

(3) Responses to Objections.

(a) No permit for which an application must be transmitted to the Administrator under this section shall be issued by the Tribe if the Administrator determines that issuance of the proposed permit would not be in compliance with applicable requirements, including this code, and so objects to its issuance in writing within 45 days of receipt of the proposed permit and all necessary supporting information.

(b) Any EPA objection under paragraph (a) of this section shall include a statement of the Administrator's reasons for objection and a description of the terms and conditions that the permit must include to respond to the objections. The Administrator will provide the permit applicant a copy of the objection.

(c) Failure of the Tribe to do any of the following also shall constitute grounds for an objection:

(i) Comply with § 2-108(2)(a) or (b);

(ii) Submit any information necessary to review adequately the proposed permit; or

(iii) Process the permit under the procedures of § 2-109 of this code except for minor permit revisions (i.e., the procedures approved to meet 40 CFR Part 70.7(h)).

(d) Unless the following requirements are waived by the Administrator pursuant to § 505(d) of the Clean Air Act, 42 U.S.C. § 7661d(d):

(i) The Tribe shall respond in writing to any objection by the Administrator to the issuance of a permit, pursuant to § 505(b) of the Clean Air Act, 42 U.S.C. § 7661d(b), and this code;

(ii) Upon receipt of an objection by the Administrator under § 505(b) of the Clean Air Act, 42 U.S.C. § 7661d(b), the Tribe may not issue the permit unless it is revised and issued in accordance with subsection (4) of this section; and

(iii) If the Tribe has issued a permit before receipt of an objection by the Administrator under § 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), the Tribe may issue a revised permit in accordance with subsection (4) of this section.

(4) Issuance or Denial.

(a) The Tribe shall, within 90 days after the date of an objection under § 505(b) of the Clean Air Act, 42 U.S.C. § 7661d(b), submit to the Administrator a proposed permit revised to meet the objection. The Tribe may request a 90-day extension for this submittal, in accordance with § 505(e) of the Clean Air Act, 42 U.S.C. § 7661d(e).

(b) If the Administrator finds that cause exists to terminate, modify, or revoke and reissue a permit pursuant to § 2-112 of this code, the Administrator will notify the Tribe and the permittee of such finding in writing.

(c) If the Administrator notifies the Tribe that cause exists to terminate, modify, or revoke and reissue a permit, the Tribe forward to the Administrator a proposed determination of termination, modification, or revocation and reissuance, as appropriate, within 90 days after receipt of such notification, the Administrator will issue or deny the permit in accordance with the requirements of the Federal program promulgated under title V of the Act.

(d) If the Tribe fails to submit a proposed determination pursuant to paragraph (c) of this section or fails to resolve any objection pursuant to paragraph (a) of this section, the Administrator will terminate, modify, or revoke and reissue the permit after taking the following actions:

(i) Providing at least 30 days' notice to the permittee in writing of the reasons for any such action. This notice may be given during the procedures in paragraphs (a) through (c) of this section.

(ii) Providing the permittee an opportunity for comment on the Administrator's proposed action and an opportunity for a hearing.

2-109. Public Notice and Participation.

(1) Applicability. Proceedings for all initial permit issuances, significant permit revisions, renewals, reopenings, revocations, and terminations, shall include public notice and provide an opportunity for public comment. The Tribe may hold a public hearing for draft permits, proposals to suspend, reopen, revoke, or terminate a permit, or for any reason the Tribe deems appropriate, and shall hold such a hearing in the event of significant public interest.

(2) Timing. The Tribe shall provide 30 days for public comment and shall give notice of any public hearing at least 30 days in advance of the hearing.

(3) Scope and Content of Notice. Public notice, whether for comment or hearing shall be given by publication in a newspaper of general circulation in the area where the source is located (e.g., the Southern Ute Tribal Drum, the Durango Herald, the Pine River Times, the Pagosa Sun, the Farmington Daily Times, or the Cortez Journal) or in a state publication designed to give general public notice, to persons on a mailing list developed by the Tribe, including those who request in writing to be on the list, and by other means if necessary to assure adequate notice to the affected public. The notice shall identify the affected facility; the name and address of the permittee; the name and address of the Tribe's Air Quality Program; the activity or activities involved in the permit action; the emissions change involved in any permit revision; the name, address, and telephone number of a person from whom interested persons may obtain additional information, including copies of the draft permit, the application, and relevant supporting materials; a brief description of the comment procedures required by this part; and as appropriate the time and place of any hearing that may be held, including a statement of procedures to request a hearing (unless a hearing has already been scheduled). Additionally, the Tribe shall provide such notice and opportunity for participation by affected programs as is provided for in § 2-108 of this code.

(4) Hearings. Public hearings shall be held on the Reservation. The time, date, and place of the hearing shall be determined by the Tribe. The Tribe shall appoint a hearing officer. A transcript of the hearing shall be made upon request at the expense of the person requesting the transcript. At the hearing, all interested persons shall be given a reasonable chance to submit data, views or arguments orally or in writing and to examine witnesses testifying at the hearing.

(5) Recordkeeping. The Tribe shall keep a record of commenters involved and issues raised during the public participation process and any other information requested by the Administrator so that the Administrator may fulfill his or her obligation under § 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), to determine whether a citizen petition may be granted. Such records shall be available to the public upon request.

(6) Response to Comments.

(a) At the time any final permit decision is issued, the Tribe shall issue a response to public comments.

(b) Any documents cited in the response to comments shall be included in the administrative record for the final permit decision. If new points are raised or new material is supplied during the public comment period, the Tribe may document the response to those matters by adding new materials to the administrative record.

(c) The Tribe shall notify in writing any affected program of any refusal to accept recommendations for the permit that the affected program submitted during the public comment and affected program review periods.

(7) Public Petitions to the Administrator.

(a) If the Administrator does not object in writing under § 2-108(3) of this code, any person may petition the Administrator within 60 days after expiration of the Administrator's 45-day review period to make such objection.

(b) Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment periods provided for above, unless the petitioner demonstrates that it was impracticable to raise such objections within such periods, or unless the grounds for such objection arose after such periods.

(c) If the Administrator objects to a permit as a result of a petition filed under this subsection, the Tribe shall not issue the permit until the Administrator's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and before the Administrator's objection.

(d) Pending resolution of any public petition to the Administrator under this subsection, the relevant source will not be in violation of the requirement to submit a timely and complete application.

(8) Administrative Review. An applicant, any person who participated in the public comment process and is aggrieved by a final action or inaction of the Tribe under this code, and any other person who could obtain judicial review of that action under applicable law, may appeal to the Commission in accordance with this code and the Commission's Procedural Rules. Solely for the purpose of obtaining administrative review before the Commission for failure to take final action, final permit action shall include the failure of the Tribe to take final action on an application for a permit, permit renewal, or permit revision (including a minor permit revision) within the time specified in this code. The opportunity for administrative review described in this section shall be the exclusive means for obtaining review of the terms and conditions of permits. Petitions for administrative review must be filed no later than 60 days after the final permit action. Notwithstanding the preceding requirement, petitions for administrative review of final permit actions can be filed after the deadline designated by the Commission, only if they are based solely on grounds arising after the deadline for administrative review. Such petitions shall be filed no later than 60 days after the new grounds for review arise. If the final permit action being challenged is the Tribe's failure to take final action, a petition for administrative review may be filed any time before the Tribe denies the permit or issues the final permit.

2-110. Permit Content.

(1) Standard Requirements. Each operating permit shall include the following:

(a) The date of issuance and the permit term, which shall be for a fixed term of 5 years in the case of affected sources and all other sources (notwithstanding this requirement, the Tribe shall issue permits for solid waste incineration units combusting municipal waste subject to standards under Section 129(e) of the Act for a period not to exceed 12 years and shall review such permits at least every 5 years);

(b) For major sources, all applicable requirements for all relevant emissions units in the major source and, for non-major sources subject to this code, all applicable requirements applicable to emissions units that cause the source to be subject to this code;

(c) Fugitive emissions from a Part 70 source, which shall be included in the same manner as stack emissions, regardless of whether the source category in question is included in the list of sources contained in the definition of major source;

(d) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance. Such requirements and limitations may include ARMs identified by the source in its part 70

permit application as approved by the Tribe, provided that no ARM shall contravene any terms needed to comply with any otherwise applicable requirement or requirement of this code or circumvent any applicable requirement that would apply as a result of implementing the ARM.

(i) The permit shall specify and reference the origin of and authority for each term or condition and identify any difference in form as compared to the applicable requirement upon which the term or condition is based.

(ii) The permit shall state that, where an applicable requirement of the Clean Air Act is more stringent than an applicable requirement of regulations promulgated under title IV of the Clean Air Act, both provisions shall be incorporated into the permit and shall be enforceable by the Tribe and Administrator.

(iii) If an applicable implementation plan allows a determination of an alternative emission limit at a part 70 source, equivalent to that contained in the plan, to be made in the permit issuance, renewal, or significant modification process, and the Tribe elects to use such process, any permit containing such equivalency determination shall contain provisions to ensure that any resulting emissions limit has been demonstrated to be quantifiable, accountable, enforceable, and based on replicable procedures.

(e) A permit condition prohibiting emissions exceeding any allowances that the source lawfully holds under title IV of the Act or the regulations promulgated thereunder.

(i) No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit revision under any other applicable requirement.

(ii) No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

(iii) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under title IV of the Act.

(f) A severability clause to ensure the continued validity of the various permit requirements in the event of a challenge to any portions of the permit;

(g) A provision specifying the conditions under which the permit will be reopened prior to expiration pursuant to § 2-112 of this code; and

(h) A provision to ensure that the permittee pays fees to the Tribe consistent with the annual fee schedule in § 2-119 of this code.

(2) Commission and Federal Requirements. Permits shall be issued containing all applicable requirements, including requirements from both the Commission and from federal program regulations requirements. This situation may arise, for example, when a permittee is subject to more than one program under the Clean Air Act and the Commission has chosen to implement only some but not all of the programs to which the permittee is subject.

(3) Required Statements. Each operating permit shall include provisions stating the following:

(a) The permittee shall comply with all terms and conditions of the permit; noncompliance with federally enforceable or Commission-only permit conditions constitutes a violation of this code and the Clean Air Act, and any permit noncompliance constitutes grounds for enforcement action, permit termination, revocation and reissuance, or revision or for denial of a permit renewal application;

(b) It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit;

(c) The permit may be modified, reopened and revised, revoked and reissued, or terminated for cause in accordance with § 2-112 of this code;

(d) The filing by the permittee of a request for a permit revision, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance shall not stay any permit condition;

(e) The permit does not convey any property rights of any sort, or any exclusive privilege;

(f) All permit terms and conditions which are required under the Clean Air Act or under any of its applicable requirements, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Clean Air Act, except that the permit shall specifically designate as not being federally enforceable under the Clean Air Act any terms or conditions included in the permit that are not required under the Clean Air Act or under any of its applicable requirements. Terms and conditions so designated are not subject to the

requirements of §§ 2-108, 2-111, 2-112, other than those contained in this paragraph (f) of this section; and

(g) The issuance of a permit, or the filing or approval of a compliance plan, does not relieve any person from civil or criminal liability for failure to comply with the provisions of this code and the Clean Air Act, applicable regulations thereunder, and any other applicable law or regulation.

(4) Hazardous Air Pollutant Requirements. Each operating permit for sources of hazardous air pollutants shall include the elements required under the Clean Air Act and its applicable regulations.

(5) Monitoring Requirements. Each operating permit shall include the following requirements:

(a) All monitoring requirements and analysis procedures or test methods required under applicable monitoring and testing requirements, including 40 CFR Part 64, and any other procedures and methods promulgated by the Administrator pursuant to § 114(a)(3) or 504(b) of the Clean Air Act or by the Commission. If more than one monitoring or testing requirement applies, the permit may specify a streamlined set of monitoring or testing provisions provided that the specified monitoring or testing is adequate to assure compliance at least to the same extent as the monitoring or testing applicable requirements that are not included in the permit as a result of such streamlining;

(b) Where the applicable requirement does not require periodic testing or instrumental or non-instrumental monitoring (which may consist of recordkeeping designed to serve as monitoring), periodic monitoring sufficient to yield reliable data from the relevant time periods that are representative of the source's compliance with its permit, as reported pursuant to § 2-110(7) of this code, provided that such monitoring requirements shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement. Recordkeeping provisions may be sufficient to meet the requirements of this paragraph; and

(c) As necessary, requirements concerning the use, maintenance, and, when appropriate, installation of monitoring equipment or methods.

(6) Recordkeeping Requirements.

(a) The permit shall require recordkeeping sufficient to assure and verify compliance with the terms and conditions of the permit, including incorporation of all applicable recordkeeping requirements, and shall require, where applicable, recordkeeping of:

(i) The date, place as defined in the permit, and time of sampling or measurements;

(ii) The date(s) analyses were performed;

(iii) The company or entity that performed the analyses;

(iv) The analytical techniques or methods used;

(v) The results of such analyses; and

(vi) The operating conditions existing at the time of sampling or measurement.

(b) Records of all monitoring data and support information shall be retained for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application and shall be kept at the location specified in the permit or elsewhere, if agreed upon in writing by the Tribe. Support information includes all calibration and maintenance records and all back-up recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

(7) Reporting Requirements. The permit shall require reporting sufficient to assure and verify compliance with the terms and conditions of the permit and all applicable requirements, including incorporation of all applicable reporting requirements and:

(a) Submittal of reports of any required monitoring at least every 6 months, which reports shall be certified by a responsible official consistent with § 2-105 of this code and shall clearly identify all instances of deviations from permit requirements, including emergencies;

(b) Prompt reporting of all deviations from permit requirements (including emergencies), including the date, time, duration, and probable cause of such deviations, the quantity and pollutant type of excess emissions resulting from the deviation, and any preventative, mitigation, or corrective actions or measures taken. Where the underlying applicable requirement contains a definition of "prompt" or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations shall be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in an applicable regulation) that continue for more

than an hour in excess of permit requirements, the report must be made by telephone, verbal, or facsimile communication by the close of business the next working day, upon discovery of the occurrence, and in writing within 10 working days from the occurrence;

(ii) For emissions of any regulated air pollutant, excluding those listed in § 2-110(7)(b)(i) of this code, that continue for more than 2 hours in excess of permit requirements, the report must be made by telephone, verbal, or facsimile communication by the close of business the next working day, upon discovery of the occurrence, and in writing within 10 working days from the occurrence;

(iii) Or all other deviations from permit requirements, the report shall be contained in the report submitted in accordance with the time frame given in § 2-110(7)(a) of this code.

(c) A permit may contain a more stringent reporting requirement than required by § 2-110(7)(b) of this code.

(d) For purposes of this section, the term "deviation" shall have the meaning prescribed in § 1-103(21) of this code.

(e) When requested by the Tribe in writing and within the period specified by the Tribe, the permittee shall furnish to the Tribe copies of records required by the permit to be maintained, and any information that the Tribe may deem necessary to determine whether cause exists for reopening and revising, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Tribe copies of records required to be kept by the permit or, for information claimed to be confidential, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

(8) Operational Flexibility Requirements. Each operating permit shall include the following:

(a) A provision stating that no permit revision shall be required for changes that are provided for in the permit under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes;

(b) Terms and conditions for reasonably anticipated AOSs identified by the source in its application as approved by the Tribe. Such terms and conditions:

(i) Shall require the source, contemporaneously with making a change from one operating scenario to another, to record in a log at the permitted facility a record of the AOS under which it is operating;

(ii) May extend the permit shield described in paragraph (10) of this section to all terms and conditions under each such AOS; and

(iii) Must ensure that the terms and conditions of each AOS meet all applicable requirements and the requirements of this code. The Tribe shall not approve a proposed AOS into the part 70 permit until the source has obtained all authorizations required under any applicable requirement relevant to that AOS.

(c) Terms and conditions identified in the application and approved by the Tribe for the trading of emissions increases and decreases within the permitted facility, provided that such trading shall be authorized solely for the purpose of complying with a federally enforceable emissions cap established in the permit independent of otherwise applicable requirements, and provided further that such terms and conditions shall:

(i) Be issued only to the extent that the applicable requirements provide for trading such increases and decreases without a case-by-case approval;

(ii) Require compliance with all applicable requirements and include all terms and conditions required under this section to determine compliance, provided that the applicant shall include in the application proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable and enforceable, and the Tribe shall not include in the emissions trading provisions any emissions units for which emissions are not quantifiable or for which there are no replicable procedures to enforce the emissions trades; and

(iii) Require for each such proposed change that the permittee provide written notification to the Tribe and the Administrator at least 7 days in advance thereof, which notice the permittee and Tribe shall attach to their copies of the relevant permit. Such notice shall specify when the proposed change will occur; shall describe the proposed change, including the resulting emissions changes and the pollutants emitted subject to the emissions trade, and how the change will comply with the terms and conditions of the permit; and shall specify the provisions of this code with which the source will comply in making the change.

(d) Provisions prohibiting sources from making, without a permit revision, changes that are not addressed or prohibited by the part 70 permit, if such changes are subject to any requirements under title IV of the Act or are modifications under any provision of title I of the Act.

(9) Compliance Requirements. Each operating permit shall include the following requirements:

(a) Consistent with §§ 2-110(5), (6), and (7), compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with the terms of the permit. Any document (including reports) required by a Part 70 permit shall contain a certification by a responsible official that meets the requirements of § 2-105 of this code;

(b) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized representatives of the Tribe or other authorized representative to perform the following:

(i) Enter the permittee's premises where a source is located or an emissions related activity is conducted, or where records must be kept under the conditions of the permit;

(ii) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(iii) Inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

(iv) Sample or monitor, at reasonable times, any substances or parameters for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act;

(c) Annual submittal of compliance certifications to the Tribe and the Administrator, which shall certify the source's compliance status with all permit terms and conditions and all applicable requirements relevant to the source, including those related to emission limitations, standards, or work practices, and shall include:

(i) The identification of each term or condition of the permit that is the basis of the certification;

(ii) The compliance status of the source;

(iii) Whether compliance was continuous or intermittent;

(iv) The method(s) used for determining the compliance status of the source, currently and during the reporting period identified in the permit. Such methods shall include, at a minimum, the methods required under § 2-110(5) through § 2-110(7) of this code;

(v) An identification of each deviation, which shall be taken into account in the compliance certification, and an identification as possible exceptions to compliance of any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred; and

(vi) Such other information as the Tribe may require to determine the compliance status of the source, and such additional requirements as may be specified pursuant to §§ 114 and/or 504(b) of the Clean Air Act, 42 U.S.C. §§ 7414, 7661c(b);

(d) Consistent with § 2-106(4)(l) of this code, for sources to which that provision applies:

(i) A compliance schedule; and

(ii) A requirement that such sources submit progress reports at least semiannually, or at a more frequent period if specified in the applicable requirement or by the Tribe, which progress reports shall contain:

(A) Dates for achieving the activities, milestones, or compliance required in the compliance schedule, and dates when such activities, milestones, or compliance were achieved; and

(B) An explanation of why any dates in the compliance schedule were not or will not be met, and any preventive or corrective measures adopted; and

(e) When required, the permittee shall submit such reports using the most recent forms and documents provided by the Tribe.

(f) Such additional compliance requirements as the Tribe may specify.

(10) Permit Shield.

(a) Except as provided in this code, the Tribe may expressly include in an operating permit a provision stating that compliance with the conditions of the permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

(i) Such applicable requirements are included and specifically identified in the permit; or

(ii) The Tribe, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

(b) An operating permit that does not expressly state that a permit shield exists for a specific provision shall be presumed not to provide such a shield for that provision.

(c) Nothing in this section or in any operating permit shall alter or affect the following:

(i) The provisions of § 303 of the Clean Air Act, 42 U.S.C. § 7603 concerning emergency powers, including the authority of the Administrator under those sections;

(ii) The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

(iii) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Act; or

(iv) The ability of the Administrator to obtain information from a source pursuant to § 114 of the Clean Air Act, 42 U.S.C. § 7414.

(d) The permit shield shall not extend to § 2-110(8) changes, off-permit, and 502(b)(10) changes under § 2-116 of this code, or minor permit revisions under § 2-111(3) of this code, or permit terms or conditions for which notice has been given to reopen or revoke all or part under § 2-112 of this code.

2-111. Permit Revisions.

The permittee must apply for any changes made to the permit that do not fall under § 2-116 of this code.

(1) Hazardous Air Pollutant Sources. Any permit revision concerning the hazardous air pollutant portion of a permit shall be governed by this code and § 112 of the Clean Air Act, 42 U.S.C. § 7412.

(2) Administrative Permit Revisions.

(a) The Tribe may incorporate administrative permit revisions as defined in § 1-103(3) of this code without providing notice to the public or affected programs, provided that the Tribe designates any such permit revision as having been made pursuant to this subsection. The Tribe shall submit a copy of the revised permit to the Administrator.

(b) The Tribe shall take no more than 60 days from receipt of a request for an administrative permit revision to take final action on such request.

(c) The permittee may implement an administrative permit revision immediately upon submittal of the request for the administrative revision.

(d) The Tribe may, upon taking final action granting a request for an administrative permit revision allow coverage by the permit shield in § 2-110(10) for administrative permit revisions made pursuant to RAC 1-103(3)(d) which meet the relevant requirements for significant permit revisions.

(3) Minor Permit Revisions.

(a) Application: A permittee may apply to the Tribe for a minor permit revision as defined in § 1-103(40) of this code in compliance with § 2-106(4) of this code, provided that such application shall include:

(i) A request for a minor permit revision;

(ii) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

(iii) If changes are requested to the permit language, the permittee's suggested draft permit changes;

(iv) Certification by a responsible official, consistent with § 2-105 of this code, that the proposed revision meets the criteria for use of minor permit revision procedures and a request that such procedures be used;

(v) Completed forms for the Tribe to use to notify the Administrator and affected programs as required under § 2-108 of this code; and

(vi) If the requested permit revision would affect existing compliance plans or schedules, related progress reports, or certification of compliance requirements, and an outline of such effects.

(b) Limitation: A permittee shall not submit multiple minor permit revision applications that may conceal a larger revision that would not constitute a minor permit revision. The Tribe may require that multiple related minor permit revision applications be submitted as a single significant permit revision application. A permit modification for purposes of the acid rain portion of the permit shall be governed by regulations promulgated under title IV of the Act.

(c) Completeness: The Tribe shall, within 30 days after receipt of an application for a minor permit revision, review such application for completeness. The Tribe shall notify the applicant of that determination by electronic mail with delivery and read receipts, provided that any incompleteness notice shall also state what additional information or points of clarification are necessary for the application to be determined complete. Unless the Tribe determines that such an application is not complete, requests additional information, or otherwise notifies the applicant of incompleteness within that time period, the application shall be deemed complete.

(d) EPA and Affected Program Review: Within 5 working days after receipt of notification by the Tribe that a minor permit revision application has been determined complete, the Tribe shall send any notice required under § 2-108(2) of this code to the Administrator and affected programs. Within 5 days after completion of the preceding review process, the Tribe shall send to the Administrator any notice required under § 2-108(3)(b) of this code.

(e) Permittee's Ability to Make Change: The permittee may make the change proposed in its minor permit revision application immediately after it files such application, provided, however, for sources that have previously utilized this provision during the term of the permit and, on two or more occasions have failed to file a complete application, may thereafter make the change only after the application is deemed complete. After the permittee makes the change and until the Tribe takes any of the actions specified in the following subsection, the permittee must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this period, the permittee need not comply with the existing permit terms and conditions it seeks to modify. If the permittee fails to comply with its proposed permit terms and conditions during this period, however, the existing permit terms and conditions it seeks to modify may be enforced against it. The filing of a minor permit revision application does not authorize construction or modification of a source under the NSR preconstruction permit program. It is the permittee's responsibility to determine if a preconstruction permit is required prior to commencing construction, modification, or reconstruction.

(f) Timetable: The Tribe may not issue a final minor permit revision until after the end of the Administrator's 45-day review period of the proposed permit revision, or until the Administrator has notified the Tribe that the Administrator will not object to issuance of the permit revision, whichever is first. Within 90 days after receipt of a complete minor permit revision application, or within 15 days after the end of the Administrator's 45-day review period, whichever is later, the Tribe shall:

(i) Issue the minor permit revision as proposed;

(ii) Disapprove the minor permit revision application;

(iii) Determine that the requested revision does not constitute a minor permit revision and should be reviewed as a proposed significant permit revision; or

(iv) Revise the draft permit revision and transmit to the Administrator the new proposed permit revision as required by § 2-108(2) of this code.

(4) Significant Permit Revisions.

(a) Significant permit revisions as defined in § 1-103(61) of this code shall meet all requirements of this code for permit issuance and renewal, including those for applications, review by the Administrator and affected programs, and public participation.

(b) The Tribe shall complete the review of the majority of significant permit revision applications within 9 months after such applications are determined to be complete. Significant permit revision applications shall be considered in the order in which they are determined to be complete, based on the order of receipt.

2-112. Permit Reopenings, Revocations and Reissuances, and Terminations.

(1) Action by the Tribe.

(a) Reopening and Revocation and Reissuance Standards: The Tribe shall reopen and revise all permits issued under this code for any of the reasons listed in paragraphs (i) through (iv) of this subsection. Alternatively, the Tribe may revoke and reissue permits for the reasons listed in paragraphs (iii) and (iv) of this subsection:

(i) Additional requirements under the Clean Air Act become applicable to a major source with a remaining permit term of 3 or

more years, provided that the Tribe shall revise such permits to incorporate such additional requirements no later than 18 months after promulgation of such requirements, and no such reopening is required if the effective date of the requirement is later than the permit expiration date unless the original permit or any of its terms or conditions have been extended past the permit expiration date pursuant to § 2-104(2)(b)(iii) of this code;

(ii) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

(iii) The Tribe or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the terms or conditions of the permit; or

(iv) The Tribe or the Administrator determines that the permit must be revised or revoked and reissued to assure compliance with applicable requirements.

(b) Reopening and Revocation and Reissuance Limitations: Proceedings to reopen and revise, or revoke and reissue, a permit shall comply with the procedural requirements for initial permit issuance, and shall affect only those parts of the permit for which cause to reopen and revise, or revoke and reissue, exists. Units for which permit conditions have been revoked shall not be operated until permit reissuance. Reopenings shall be made as expeditiously as practicable.

(c) Termination: A permit, or an authorization to operate under a general permit, may be terminated when:

(i) The permittee fails to meet the requirements of an approved compliance plan;

(ii) The permittee has been in significant or repetitious noncompliance with the operating permit terms or conditions;

(iii) The applicant or permittee has exhibited a history of willful disregard for environmental laws of any tribal or state authority, or of the United States;

(iv) The applicant or permittee has knowingly misrepresented a material fact in any application, record, report, plan, or other document filed or required to be maintained under the permit;

(v) The permittee falsifies, tampers with, or renders inaccurate any monitoring device or method required to be maintained under the permit;

(vi) The permittee fails to pay fees required under § 2-118 and § 2-119, of this code; or

(vii) The Administrator has found that cause exists to terminate the permit.

(d) Notification: In addition to providing notice of intent to terminate a permit, the Tribe shall provide a notice of intent to a permittee to reopen or revoke and reissue a permit. Notice shall be provided by electronic mail with delivery and read receipts at least 30 days before the date on which the permit is to be reopened, revoked, or terminated, except that the Tribe may provide less advance notice in the case of an emergency. The notice shall state that the permittee may, within 30 days of receipt, or in less time in the case of an emergency, submit comments or request a hearing on the proposed permit action.

(2) Action by the Administrator: Within 90 days, or longer if the Administrator extends this period, after receipt of written notification that the Administrator has found that cause exists to terminate, modify, or revoke and reissue a permit, the Tribe shall forward to the Administrator a proposed determination of termination, modification, or revocation and reissuance, as appropriate. Within 90 days from receipt of an objection by the Administrator to a proposed determination, the Tribe shall address and act upon such objection.

(3) Revocation and Termination: Revocation or termination of a permit by the Tribe terminates the permittee's right to operate.

(4) Voluntary Discontinuation: Upon request by the permittee, the Tribe shall permanently discontinue an operating permit. Permit discontinuance terminates the permittee's right to operate as a Part 70 source under the permit. The Tribe shall confirm the permit discontinuance by electronic mail with delivery and read receipts to the permittee.

(5) Preconstruction Limitation: Nothing in this section shall be construed to alter any applicable preconstruction requirements under § 165 of the Clean Air Act, 42 U.S.C. § 7475.

2-113. Permit Transfers.

A permit shall not be transferable, by operation of law or otherwise, from one location to another or from one source to another, except that a permit may be transferred from one location to another in the case of a portable source that has notified the Tribe in advance

of the transfer, pursuant to this code. A permit for a source may be transferred from one person to another if the Tribe finds that the transferee is capable of operating the source in compliance with the permit and the requirements of this code. This transfer must be accomplished through an administrative permit revision as defined in § 1-103(3) of this code.

2-114. General Permits.

(1) Issuance.

(a) The Tribe may, after notice and opportunity for public participation and review by the Administrator and affected programs, issue a general permit covering numerous similar sources.

(b) Any general permit shall comply with all requirements applicable to other operating permits and shall identify criteria by which sources may qualify for the general permit.

(2) Application.

(a) The owner or operator of a Part 70 source that would qualify for a general permit must:

(i) Apply to the Tribe for coverage under the terms of the general permit; or

(ii) Apply for an operating permit consistent with § 2-106 of this code.

(b) The Tribe may, in the general permit, provide for applications which deviate from the requirements of § 2-106 of this code, provided that such applications meet the requirements of title V of the Clean Air Act and include all information necessary to determine qualification for, and to assure compliance with, the general permit.

(3) Review and Operation.

(a) The Tribe shall authorize qualifying sources that apply for coverage under a general permit to operate under the terms and conditions of such general permit.

(b) The Tribe may grant a request for authorization to operate under a general permit without repeating the public participation procedures required under § 2-109 of this code.

(c) Authorization to operate under a general permit shall not be granted for acid rain sources unless otherwise provided in regulations promulgated under title IV of the Clean Air Act.

(d) Notwithstanding § 2-110(10) of this code, the permittee shall be subject to enforcement action for operation without an operating permit if the source is later determined not to qualify for the conditions and terms of the general permit.

2-115. Portable Source Permits.

(1) Authorization. The Tribe may issue permits for portable sources that authorize emissions from similar operations by the same source owner or operator at multiple locations and authorize such sources to relocate without undergoing a major permit revision.

(2) Acid Rain Source. No acid rain source shall be permitted as a portable source.

(3) Limitations. Permits issued pursuant to this section shall include conditions to assure that:

(a) The source is installed at all locations in a manner conforming with the permit;

(b) The source shall comply with all applicable requirements and all other provisions of this code at all authorized locations;

(c) The owner or operator shall notify the Tribe in writing at least 10 days in advance of each change in location, provided that such notice shall include a legal description of where the source is to be relocated and how long, to the best of the owner or operator's knowledge, it will be located there; and

(d) Emissions from the source shall not, at any location, result in or contribute to an exceedance of a national ambient air quality standard or increment or visibility requirement under Part C of title I of the Clean Air Act.

2-116. Facility Changes Allowed Without Permit Revisions.

In addition to changes authorized pursuant to § 2-110(8) of this code, any permittee may make the following facility changes without a permit revision:

(1) Section 502(b)(10) Changes.

(a) The permittee may make Clean Air Act § 502(b)(10) changes without applying for a permit revision if those changes are not modifications under title I of the Clean Air Act and do not cause the facility to exceed

emissions allowable under the permit (whether expressed as a rate of emissions or in terms of total emissions).

(b) For each proposed § 502(b)(10) change, the permittee shall provide written notification to the Tribe and the Administrator at least 7 days in advance of the proposed change. Such notice shall state when the change will occur and shall describe the change, any resulting emissions change, and the inapplicability of any permit term or condition.

(c) Upon receiving notice of a proposed § 502(b)(10) change pursuant to the preceding provision, the Tribe shall promptly determine whether the proposed change qualifies as a § 502(b)(10) change and whether the notice meets the requirements of the preceding paragraph, and shall promptly notify the permittee of this determination.

(d) If the proposed change and the notice is sufficient, the permittee and Tribe shall attach each such notice to their copy of the relevant permit. If the change is determined not to qualify or the notice is not sufficient, the original terms of the permit remain fully enforceable.

(2) Off-Permit Changes.

(a) Permittees are allowed to make, without a permit revision, changes that are not addressed or prohibited by the operating permit, if:

(i) Each such change meets all applicable requirements and shall not violate any existing permit term or condition;

(ii) Such changes are not subject to any requirements under title IV of the Clean Air Act and are not modifications under title I of the Clean Air Act;

(iii) Such changes are not subject to permit revision procedures under § 2-111 of this code; and

(iv) The permittee provides contemporaneous written notice to the Tribe and the Administrator of each such change, except for changes that qualify as insignificant activities. Such notice shall state when the change occurred and shall describe the change, any resulting emissions change, pollutants emitted, and any applicable requirement that would apply as a result of the change.

(b) The permittee shall keep a record describing changes made at the source that result in emissions of any regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

2-117. Emergency Situations.

(1) Definition. An emergency, as defined in § 1-103(23) of this code, constitutes an affirmative defense to an action brought for noncompliance with relevant technology-based emission limitations if the permittee demonstrates through properly signed, contemporaneous operating logs or other relevant evidence that:

(a) An emergency occurred and the permittee can identify the cause(s) of the emergency;

(b) The permitted facility was being properly operated at the time;

(c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in the permit; and

(d) The permittee reported the emergency to the Tribe in compliance with § 2-110(7) of this code.

(2) Burden of Proof. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency bears the burden of proof.

(3) Other Applicable Requirements. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

2-118. Fee Requirement and Payment.

(1) Initial Fees.

(a) Part 70 sources that begin operation after the Tribe's program has been approved shall complete and submit a fee calculation work sheet, provided by the Tribe, during the first year of operation. Fee payment of the full amount must accompany each initial fee calculation work sheet.

(b) The fee calculation work sheet shall require the source to submit a report based on the emissions inventory for the preceding calendar year and to compute fees owed based on those emissions. For sources that have been issued Part 70 permits, emissions shall be computed using compliance methods required by the most recent permit. If actual emissions cannot be determined using the compliance methods in the permit, the actual emissions should be determined using federally recognized procedures. If a source commenced operation during the preceding calendar year, the source shall estimate its emissions for the current calendar year. In such a case, fees for the source shall be based on the total emissions estimated.

(c) The initial fee calculation worksheet shall be certified by a responsible official consistent with § 2-105 of this code.

(2) Annual Fees. An annual operating permit emission fee shall be paid to the Tribe by each owner or operator of a Part 70 source.

(a) Such fee shall be assessed:

(i) For a major source, for all emissions units; and

(ii) For all other sources, for emissions units that cause the source to be subject to this code.

(b) The first annual fee to be paid shall be determined and paid as follows:

(i) For sources that begin operation after the effective date of this code, and for sources that become subject to a permit requirement pursuant to title V of the Clean Air Act through promulgation of the Administrator after the effective date of this code, the first annual fee shall be based on the applicable minimum fee or the per ton fee based on the emissions inventory for the first year of operation, whichever is greater. The first annual fee shall be due on the anniversary date of the initial fee calculation work sheet at the time the initial permit application is submitted pursuant to § 2-118(1) of this code.

(ii) If no emissions inventory is available, the first annual fee shall be based on estimated emissions using approved estimation methods.

(c) All annual emission fees other than the first shall be due to the Tribe each year on the date specified in the permit. The fee shall be based on the emissions inventory for the preceding operating year or the applicable minimum fee, whichever is greater. All annual fee calculation worksheets shall be certified by a responsible official consistent with § 2-105 of this code.

(i) The permittee shall submit the initial fee calculation work sheet using the most recent form provided by the Tribe.

(3) Other Fees. The Tribe may establish a schedule of other fees necessary to ensure that fees cover program costs, as required, including but not limited to, for example, a registration fee.

(4) Payment Form, Processing, and Use.

(a) Fee payments due under this section shall be remitted in the form of a money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the Southern Ute Indian Tribe and sent or delivered to the Tribe by the United States Postal Service, c/o Environmental Programs Division Part 70 Program, P.O. Box 737 MS#84, Ignacio, Colorado 81137; or by common carriers (such as UPS or FedEx) c/o Environmental Programs Division Part 70 Program, 398 Ouray Drive, Ignacio, Colorado 81137.

(b) Upon receipt of fee payments due under this section, such payments shall be used for the administration of the Title V Operating Permit Program.

(c) Fee payments collected under this section shall not be utilized for any purpose not authorized under the Clean Air Act.

(5) Nonpayment.

(a) Failure to remit the full fee required by the due dates specified in this section constitutes a violation of this code and may subject the owner or operator to enforcement actions under this code, including, but not limited to, civil penalties for each day of noncompliance.

(b) The Tribe shall not issue a final permit or permit revision until all fees, interest and penalties assessed against a source under this section are paid.

(c) An initial or renewal application shall not be found complete unless the source has paid all fees owed.

(6) Penalty and Interest Assessment.

(a) The Tribe shall assess interest on payments which are received later than the date due. The interest rate shall be the sum of the federal short-term rate determined by the Secretary of the Treasury in accordance with Section 6621(a)(2) of the International Revenue Code of 1986, plus 3 percentage points.

(b) The Tribe shall assess a penalty charge of 50 percent of the fee amount if the fee is not paid within 30 days of the payment due date.

(c) If a source underpays the fee owed, except as provided in paragraph (6)(d) of this section, the Tribe shall assess a penalty charge of 50 percent on the amount by which the fee was underpaid. Interest shall also be assessed, computed under paragraph (6)(a) of this section, on the amount by which the fee was underpaid.

(d) If a source bases its initial fee calculation on estimated emissions from the source's current or preceding calendar year and underpays its fee based on an underestimation of these emissions, the Tribe shall assess a penalty charge of 50 percent on certain of these underpayments, according to the following provisions:

(i) The penalty charge shall be assessed whenever a source's underpayment exceeds the underpayment penalty cutoff established in paragraph (6)(d)(iii) of this section. The penalty amount shall be 50 percent of the portion of the underpayment which is in excess of the underpayment penalty cutoff.

(ii) Where a source is subject to a penalty for underpayment pursuant to paragraph (6)(d)(i) of this section, interest as computed under paragraph (6)(a) of this section shall be assessed on that portion of the underpayment which is in excess of the underpayment penalty cutoff established in paragraph (6)(d)(iii) of this section.

(iii) The underpayment penalty cutoff for a source shall be the sum of the following:

(A) 50 percent of the portion of the initial fee amount which was calculated from estimated emissions of HAP listed pursuant to § 112(b) of the Clean Air Act, and

(B) 20 percent of the portion of initial fee amount which was calculated from estimated emissions of the remainder of the fee pollutants.

2-119. Fee Schedule.

(1) Emission and Minimum Fees.

(a) Initial Emission Fees: Unless otherwise set pursuant to this section, annual emission fees for all sources required to have operating permits under this code shall be $50.00 per ton of emissions for all fee pollutants, including fugitive emissions, adjusted pursuant to paragraphs (c) and (d) of this section.

(b) Initial Minimum Fees: The Tribe may set, pursuant to this section, minimum fees for all sources required to have an operating permit under this code.

(c) Adjustments to Fees: The Tribe may alter or adjust the above emission and minimum fees in dollars per ton in the interest of program administration and/or to ensure that fees paid under this code are sufficient

to cover permit program costs, as those costs or the number or types of permitted sources may change over time. All adjustments to fees must be approved by the Commission.

(d) Indexing: The emission and minimum fees set under the preceding subsections shall be adjusted at the beginning of each calendar year to reflect any percentage increase by which the Consumer Price Index for the most recent year exceeds the Consumer Price Index for the year the Tribe's Title V Operating Permit Program was approved.

(2) Fee Calculation.

(a) Subtotal annual fees shall be calculated by multiplying the applicable emission fee set pursuant to § 2-119(1) of this code times the total tons of actual emissions for each fee pollutant. In lieu of actual emissions, annual fees may be calculated based on the potential to emit for each fee pollutant. Emissions of any regulated air pollutant that already are included in the fee calculation under a category of regulated pollutant, such as a federally listed hazardous air pollutant that is already accounted for as a VOC or as PM10, shall be counted only once in determining the source's actual emissions.

(b) The total annual fee due under this section shall be the greater of the applicable minimum fee or the sum of subtotal annual fees for all fee pollutants emitted from the source. The applicable minimum fee shall only be established, upon approval of the Commission, if necessary for the program to remain self-sustaining.

(3) Fee Assessment Errors.

(a) If the Tribe determines that a source has completed the fee calculation work sheet incorrectly, the Tribe shall bill the applicant for the corrected fee or credit overpayments to the source's account.

(b) Each source notified by the Tribe of additional amounts due shall remit full payment within 30 days of receipt of an invoice from the Tribe.

(c) An owner or operator of a Part 70 source who thinks that the assessed fee is in error shall provide a written explanation of the alleged error to the Tribe along with the assessed fee. The Tribe shall, within 90 days of receipt of the correspondence, review the data to determine whether the assessed fee was in error. If an error was made, the overpayment shall be credited to the account of the Part 70 source.

(4) Fee Demonstration. The Tribe shall provide a demonstration to the Administrator that the fee schedule established pursuant to this section, in

conjunction with any application fees established by the Tribe pursuant to this section, will result in the collection and retention of fees in an amount sufficient to cover permit program costs. Such demonstration shall also contain an initial accounting (and periodic updates as required by the Administrator) of how required fee revenues are used solely to cover permit program costs.

2-120. Reduction in Permit Fees.

The Tribe may reduce any fee required under this code to take into account the financial resources of small business sources.

2-121. Enforcement Authority.

Pursuant to the enforcement authority enumerated in P.L. 108-336 and applicable provisions of the Clean Air Act, the Tribe has the following authority to prevent and address violations of this code by Part 70 sources:

(1) **Civil Action.** To bring a civil action for declaratory or injunctive relief immediately and effectively against any person who fails to comply with terms of a permit or any program requirement, including permit conditions, or is presenting an imminent and substantial endangerment to the public health or welfare, or the environment; without the necessity of a prior revocation of the permit.

(2) **Civil Penalties and Damages.** To assess or sue to recover in court civil penalties or recover civil damages according to the following:

(a) Civil penalties or damages assessed, sought, or agreed upon by the Tribe under this section shall be appropriate to the violation;

(b) These penalties or damages shall be separately recoverable in an amount not to exceed $10,000 per day per violation;

(c) Civil penalties or damages shall be recoverable for the violation of any applicable requirement; any permit condition; any fee or filing requirement; any duty to allow or carry out inspection, entry, or monitoring activities; or any regulation or orders issued by the Tribe. Mental state shall not be included as an element of proof for civil violations.

(d) In determining the amount of any civil penalty, the following factors shall be considered:

(i) The violator's compliance history;

(ii) Good-faith efforts on behalf of the violator to comply;

(iii) Payment by the violator of penalties previously assessed for the same violation;

(iv) Duration of the violation;

(v) Economic benefit of noncompliance to the violator;

(vi) Impact on, or threat to, the public health or welfare or the environment as a result of the violation;

(vii) Malfeasance; and

(viii) Whether legal and factual theories were advanced for purposes of delay.

(e) In addition to the factors set forth above, the following circumstances shall be considered as grounds for reducing or eliminating civil penalties:

(i) The voluntary and complete disclosure by the violator of such violation in a timely fashion after discovery of the noncompliance;

(ii) Full and prompt cooperation by the violator following disclosure of the violation including, when appropriate, entering into a legally enforceable commitment to undertake compliance and remedial efforts;

(iii) The existence and scope of a regularized and comprehensive environmental compliance program or an environmental audit program;

(iv) Substantial economic impact of a penalty on the violator;

(v) Nonfeasance; and

(vi) Other mitigating factors.

(f) The imposition of civil penalties may be deferred or suspended where appropriate based on consideration of the factors set forth above.

(g) Notwithstanding any other provision in this section, no action for civil enforcement of this program may be taken where a permit renewal has been issued for the source and the source conducts its operations in compliance with the permit terms.

(3) Criminal Enforcement. In accordance with the IGA and federal law, EPA will exercise criminal enforcement jurisdiction over any persons on all lands within the Reservation boundaries for violations of the Reservation Air Program.

(4) Burden of Proof. The burden of proof and degree of knowledge or intent required for establishing violations under this § 2-121 shall be no greater than the burden of proof or degree of knowledge or intent required under the Clean Air Act.

2-122. Compliance Tracking.

(1) Generally. The Tribe shall compile and maintain for at least five years all information received pursuant to § 2-110(7) of this code as necessary and appropriate to determine ongoing compliance by Part 70 sources with this code and the Clean Air Act, and shall provide any such information or compilation thereof to the Administrator when so requested by the Administrator.

(2) Agreement. The Tribe may enter into an agreement with the Administrator concerning provision of the compliance tracking information compiled pursuant to this section.

2-123. Enforcement Reporting.

(1) Requirement. The Tribe shall record and submit to the Administrator at least annually beginning no later than one year after the effective date of this code information regarding the Tribe's enforcement activities taken pursuant to this code including but not limited to the following:

(a) The number of civil administrative and judicial enforcement actions either commenced or concluded;

(b) The penalties and damages obtained in those actions; and

(c) The number of administrative orders issued.

(2) Method. The Tribe shall consult with the Administrator regarding the preferred method for recording information required to be recorded pursuant to this section.

2-124. Confidentiality.

(1) Submittal. An applicant or permittee who submits material to the Tribe under a claim of confidentiality:

(a) May submit the material separately;

(b) Shall precisely identify the material for which the confidentiality claim is asserted; and

(c) Shall provide sufficient supporting information to allow evaluation of that claim.

(2) Eligibility. All confidentiality claims made regarding material submitted to the Tribe under this code shall be evaluated under 40 CFR § 2(B). Information which is emission data, a standard or limitation, or is collected pursuant to § 211(b)(2)(A) of the Clean Air Act is not eligible for confidential treatment, as provided in 40 CFR § 2.301(e).

(3) Submittal to Administrator. The Tribe may require or permit an applicant or permittee to submit directly to the Commission or Administrator a copy of such material for which a confidentiality claim is asserted and shall be evaluated under 40 CFR § 70.5(a)(3).

(4) Public Record. All materials submitted to the Tribe under this code, except to the extent determined confidential pursuant to this section, and all operating permits, are public records and not entitled to protection under § 114(c) of the Clean Air Act, 42 U.S.C. § 7414(c). A copy of each permit application, compliance plan (including the schedule of compliance), emissions or compliance monitoring report, certification, and each permit issued under this code, shall be available to the public. If an applicant or permittee is required to submit information entitled to protection from disclosure under this code, the applicant or permittee may submit such information separately.

(5) Sharing of Information. Any information obtained or used in the administration of this program shall be available to EPA upon request without restriction and in a form specified by the administrator, including computer-readable files to the extent practicable.

2-125. Program Revision.

Pursuant to the Commission's Procedural Rules, the Commission shall review this code no less than once every five years to make any necessary changes.

PART 2. NEW SOURCE PERFORMANCE STANDARDS

3-101. Introduction to Incorporation of Standards of Performance for New Stationary Sources.

This Part incorporates as part of the Reservation Air Program certain standards of performance established by the United States Environmental Protection Agency pursuant to section 111 of the Clean Air Act (42 U.S.C. § 7411) to regulate criteria pollutant emissions from specific categories of new sources. The purpose of the incorporation is to enable the Southern Ute Indian Tribe and the Southern Ute Indian Tribe/State of Colorado Environmental Commission to exercise authority with respect to the incorporated regulations as published and found in 40 C.F.R. Part 60.

3-102. Incorporation of NSPS by reference.

The following EPA regulations on Standards of Performance for New Stationary Sources and designated appendices, published as of November 9, 2022 not including any later amendments, are adopted by the Commission and incorporated by reference into this Reservation Air Code. All new sources of air pollution shall comply with the standards, criteria, and requirements set forth in the incorporated regulations and appendices. For the purpose of this Part, the term "new sources" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under federal law which will be applicable to such source. For the purpose of this Part, the word "Administrator" as used in the incorporated regulations means the Tribe, except for those aspects of the incorporated regulations which cannot be delegated to the Tribe, in which case, "Administrator" means both the Administrator of the Environmental Protection Agency or his authorized representative and the Tribe.

40 C.F.R. Part 60, Subpart A	General Provisions
40 C.F.R. Part 60, Subpart D	Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971
40 C.F.R. Part 60, Subpart Da	Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978
40 C.F.R. Part 60, Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
40 C.F.R. Part 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
40 C.F.R. Part 60, Subpart I	Standards of Performance for Hot Mix Asphalt Facilities

40 C.F.R. Part 60, Subpart K	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
40 C.F.R. Part 60, Subpart Ka	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984
40 C.F.R. Part 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984
40 C.F.R. Part 60, Subpart GG	Standards of Performance for Stationary Gas Turbines
40 C.F.R. Part 60, Subpart VV	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006
40 C.F.R. Part 60, Subpart KKK	Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011
40 C.F.R. Part 60, Subpart LLL	Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011
40 C.F.R. Part 60, Subpart OOO	Standards of Performance for Nonmetallic Mineral Processing Plants
40 C.F.R. Part 60, Subpart WWW	Standards of Performance for Municipal Solid Waste Landfills
40 C.F.R. Part 60, Subpart CCCC	Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction is Commenced After November 30, 1999 or for Which Modification or Reconstruction is Commenced on or After June 1, 2001

40 C.F.R. Part 60, Subpart EEEE	Standards of Performance for Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006
40 C.F.R. Part 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
40 C.F.R. Part 60, Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
40 C.F.R. Part 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines
40 C.F.R. Part 60, Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015
40 C.F.R. Part 60, Subpart OOOOa	Standards of Performance for Crude Oil and Natural gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

40 CFR part 60, Appendix A - Test Methods

40 CFR part 60, Appendix B - Performance Specifications

40 CFR part 60, Appendix C - Determination of Emission Rate Change

40 CFR part 60, Appendix D - Required Emission Inventory Information

40 CFR part 60, Appendix F - Quality Assurance Procedures

40 CFR part 60, Appendix I - Removable Label and Owner’s Manual

PART 3. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

4-101. Introduction to Incorporation of National Emission Standards for Hazardous Air Pollutants.

This Part incorporates as part of the Reservation Air Program certain National Emission Standards for Hazardous Air Pollutants (NESHAP) established by the United States Environmental Protection Agency pursuant to section 112 of the Clean Air Act (42 U.S.C. § 7412) which regulate hazardous air pollutant emissions of new and existing sources. The purpose of the incorporation is to enable the Southern Ute Indian Tribe and the Southern Ute Indian Tribe/State of Colorado Environmental Commission to exercise authority with respect to the incorporated standards. Included among the federal regulations incorporated herein are certain National Emission Standards for Hazardous Air Pollutants as published and found in 40 C.F.R. Part 61, and certain National Emission Standards for Hazardous Air Pollutants for Source Categories as published and found in 40 C.F.R. Part 63.

4-102. Incorporation of NESHAP by Reference.

The following United States Environmental Protection Agency regulations on National Emission Standards for Hazardous Air Pollutants, published as of November 9, 2022, not including any later amendments, are adopted by the Commission and incorporated by reference into this Reservation Air Code. All new and existing sources of air pollution shall comply with the standards, criteria, and requirements set forth in the incorporated regulations. For the purpose of this Part, the word "Administrator" as used in the incorporated regulations means both the Administrator of the Environmental Protection Agency or his authorized representative and the Tribe.

40 C.F.R. Part 61, Subpart A	General Provisions
40 C.F.R. Part 61, Subpart M	National Emission Standard for Asbestos
40 C.F.R. Part 61, Subpart V	National Emission Standard for Equipment Leaks (Fugitive Emission Sources)

(1) Incorporation of Appendices. The following appendices as revised and published as of November 9, 2022, not including any later amendments, are adopted by the Commission and incorporated by reference into this Reservation Air Code. Copies of the incorporated appendices can be obtained from the Southern Ute Indian Tribe, Air Quality Program, P.O. Box 737 MS#84, Ignacio, Colorado 81137.

40 C.F.R. Part 61, Appendix A - Compliance Status Information

40 C.F.R. Part 61, Appendix B - Test Methods

40 C.F.R. Part 61, Appendix C - Quality Assurance Procedures

4-103. Incorporation of NESHAP for Source Categories by Reference.

The following United States Environmental Protection Agency regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories, published as of November 9, 2022, not including any later amendments, are adopted and incorporated by reference into this Reservation Air Code. All new and existing sources of air pollution shall comply with the standards, criteria, and requirements set forth in the incorporated regulations. For the purpose of this Part, the word "Administrator" as used in the incorporated regulations means both the Administrator of the Environmental Protection Agency or his authorized representative and the Tribe.

40 C.F.R. Part 63, Subpart A	General Provisions
40 C.F.R. Part 63, Subpart B	Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)
40 C.F.R. Part 63, Subpart C	List of Hazardous Air Pollutants, Petitions Process, Lesser Quantity Designations, Source Category List
40 C.F.R. Part 63, Subpart N	National Emission Standards for Chromium Emissions from Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks
40 C.F.R. Part 63, Subpart Q	National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers
40 C.F.R. Part 63, Subpart HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities
40 C.F.R. Part 63, Subpart OO	National Emission Standards for Tanks - Level 1
40 C.F.R. Part 63, Subpart HHH	National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities
40 C.F.R. Part 63, Subpart AAAA	National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills
40 C.F.R. Part 63, Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
40 C.F.R. Part 63, Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 C.F.R. Part 63, Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
40 C.F.R. Part 63, Subpart GGGGG	National Emission Standards for Hazardous Air Pollutants: Site Remediation
40 C.F.R. Part 63, Subpart CCCCCC	National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities
40 C.F.R. Part 63, Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

(1) Incorporation of Appendices. The following appendices, published as of November 9 , 2022, not including any later amendments, are adopted by the Commission and incorporated by reference into this Reservation Air Code. Copies of the incorporated appendices can be obtained from the Southern Ute Indian Tribe, Air Quality Program, P.O. Box 737 MS#84, Ignacio, Colorado 81137.

40 C.F.R. Part 63, Appendix A	-	Test Methods
40 C.F.R. Part 63, Appendix C	-	Determination of the Fraction Biodegraded (F_{bio}) in a Biological Treatment Unit
40 C.F.R. Part 63, Appendix D	-	Alternative Validation Procedure for EPA Waste and Wastewater Methods

History and Amendments

- Article I and Article II, Part I approved by Southern Ute Indian Tribe/State of Colorado Environmental Commission on November 12, 2008.

- Amended June 14, 2010.

- Amended August 8, 2011.

- Effective date of Article I and Article II, Part I: March 2, 2012 (77 Fed. Reg. 15267 (2012)), upon approval by EPA.

- Article I and Article II amended to add certain CAA Section 111 NSPS and CAA Section 112 NESHAP provisions as Article II, Part 2 and Part 3, respectfully; and to correct formatting, spacing, typographical errors and incorrect reference citations. The amendments were approved by EPA on September 3, 2013 and delegation for Tribe to implement and enforce NSPS and NESHAP was granted effective September 6, 2013 (78 Fed. Reg. 40635 (2013)). The amendments were adopted by Southern Ute Indian Tribe/State of Colorado Environmental Commission as non-controversial revisions on November 14, 2012 through a direct final rulemaking and became effective on January 28, 2013.

- Article 2, Part 1 amended to include CAA Section 113 civil penalty assessment criteria under the enforcement authority of RAC 2-121, reword specific regulatory language for clarification, and correct typographical errors and incorrect reference citations. The amendments were adopted by the Southern Ute Indian Tribe/State of Colorado Environmental Commission as non-controversial revisions on June 3, 2014 through a direct final rulemaking and became effective on August 23, 2014. The amendments were approved by EPA on July 16, 2014.

- Article 1 amended to include CAA Section 114 investigation and information request authority under RAC 1-105 and cease and desist authority for air pollution emergencies endangering public health or welfare on the Reservation under RAC 1-106. The amendments were adopted by the Southern Ute Indian Tribe/State of Colorado Environmental Commission as non-controversial revisions on October 19, 2015 through a direct final rule making and became effective December 26, 2015. The amendments were approved by EPA on January 28, 2016.

- Amended: January 17, 2022:

  Article II, Part 2

  - Removed language limiting the Tribe's 40 C.F.R. 60 enforcement primacy to only Tribally permitted sources.

        - Incorporated 40 C.F.R. 60, Subpart OOOOa. Subpart OOOOa became effective on August 2, 2016.

    - Article II, Part 3:

        - Removed language limiting the Tribe's 40 C.F.R. 63 enforcement primacy to only Tribally permitted sources.

        - Incorporated 40 C.F.R. 63, Subpart DDDDD, Subpart GGGGG, Subpart CCCCCC, and Subpart JJJJJJ.

- Amended: September 15, 2023

    - Article I:

        - Amended to update definition of "Major Source" for consistency with federal regulations.

        - Amended to correct one incorrect citation reference.

    - Article II: Part 1:

        - Amended to require permittee to use most recent forms developed by the Tribe when submitting applications and to eliminate the requirement for the submittal of hard copy written forms.

        - Amended to remove the certified mail requirements for notification of completeness determinations on permit applications.

        - Removed citations referencing the original Title V transition program.

        - Amended to include a 30-day notification to the Tribe of initial or revised NSR permits and to clarify time frame for which a Title V permit revision application shall be submitted following issuance of an initial or revised NSR permit.

        - Amended to require permittee to use the most recent forms developed by the Tribe when submitting initial and annual fee calculation work sheets.