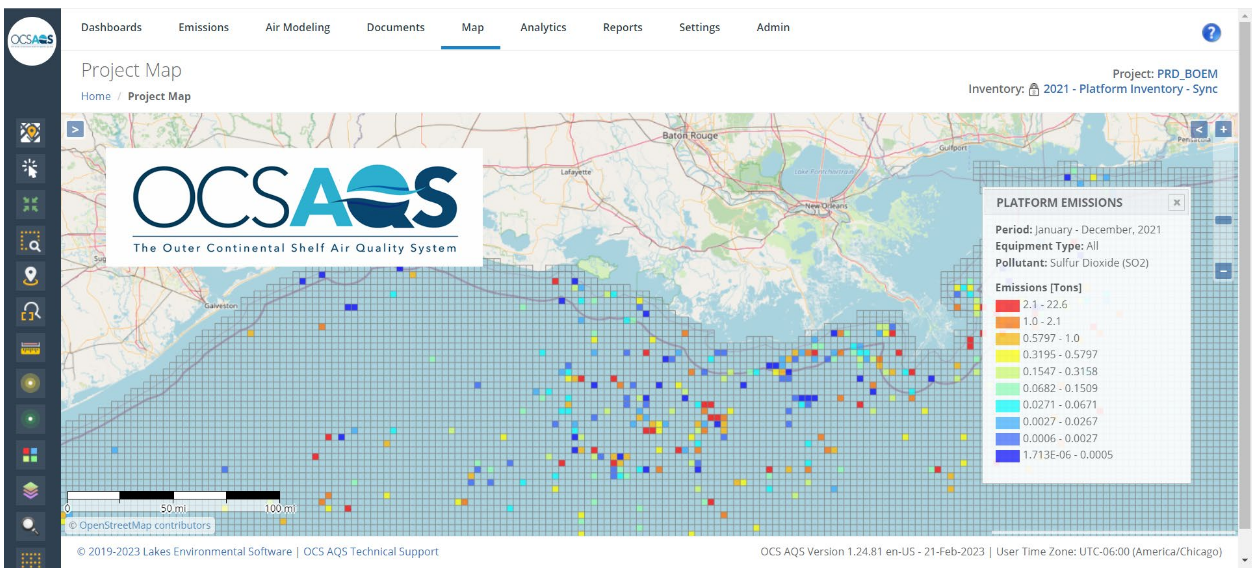
OCS Study
BOEM 2023-023

Outer Continental Shelf Air Quality System (OCS AQS): Year 2021 Emissions Inventory Quality Assurance/Quality Control (QA/QC) Study



BSEE
Bureau of Safety and Environmental Enforcement

BOEM
Bureau of Ocean Energy Management

U.S. Department of the Interior
Bureau of Ocean Energy Management
Sterling, VA

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DISCLAIMER

Study concept, oversight, and funding were provided by the U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM), Environmental Studies Program, Washington, DC, under Contract Number 140E0119C0006. This report has been technically reviewed by BOEM, and it has been approved for publication. The views and conclusions contained in this document are those of the authors and should not be interpreted as representing the opinions or policies of BOEM, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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CITATION

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Abstract

This report describes the approach, findings, analysis, and conclusions of a study funded by the Bureau of Ocean Energy Management (BOEM) and conducted by the Xator-Lakes team (the Team) to perform quality assurance (QA) and quality control (QC) and finalize 2021 emissions inventory data. This data was required to be submitted by oil and gas operators operating in Federal waters in the Gulf of Mexico (GOM) west of 87° 30' West longitude. The reporting requirement also applied to operators on the North Slope Borough of Alaska; however, there was no Outer Continental Shelf (OCS) oil or gas activity in this region. Therefore, this report only details the GOM emissions inventory finalization.

The operators reported their required activity data using the new web-based Outer Continental Shelf Air Quality System (OCS AQS), which recently replaced the legacy Gulfwide Offshore Activity Data System (GOADS). The Team supported four related objectives under the study: (1) conducting forensic-level QA/QC of the submitted 2021 platform emissions data; (2) reviewing and analyzing the emission factors and calculations used; (3) completing QA/QC of drilling rigs (non-platform) activity data; and (4) finalizing 2021 emissions data in OCS AQS. This report presents the 2021 final emissions data.

OCS AQS automatically performs baseline checks at the time of operator input and submission to ensure that all required data are entered by the operators and the input values are within pre-defined ranges approved by BOEM. However, an extensive and in-depth QA/QC effort was necessary afterwards to identify potential outliers, discrepancies, and errors that might require correction. Various statistical and visual inspection methods were used for this purpose, including the use of built-in analytics and reporting tools within OCS AQS. The Team also investigated the completeness of the inventory by comparing the list of facilities in OCS AQS against the Technical Information Management System (TIMS) database (maintained and operated by the Bureau of Safety and Environmental Enforcement) and by following up on facilities that did not report emissions. Follow-up was done with the operators to verify all potential issues and ensure that all requested corrections were completed in a timely manner.

Afterwards, the study conducted an in-depth comparison against the 2017 inventory data (Wilson et al. 2019) to understand the changes in emission totals and reasons for these changes, by pollutants and equipment types. The analysis also reviewed emission factors and calculation methods against those used in 2017, as well as against the latest data in *AP-42: Compilation of Air Emissions Factors*, published by the U.S. Environmental Protection Agency (USEPA 1995). The changes in emission factors generally are believed to have had a negligible impact overall on the total 2021 emissions. Finally, this was the first inventory year in which the operators were asked to report their lease operations data (non-platform facility sources); therefore, no comparisons were possible to the 2017 data, but a similar process of contacting and following up with the operators for outliers was followed to ensure data quality.

In total, the study identified 227 facilities owned by 46 companies needing corrective action to address their platforms' activity data issues. The Team incorporated the operators' revisions into the main 2021 database in OCS AQS. This revised database represents the 2021 final inventory. Table 1 provides a summary of the 2021 final total annual greenhouse gas (GHG) emissions in tons per year by equipment type, with the highest source contribution emissions number bolded per GHG.

Table 2 provides a summary of the 2021 final total annual criteria pollutants and precursors in tons per year by equipment type, with the highest source contribution emissions number bolded per pollutant. Additional details regarding the 2021 final GHGs and criteria emissions are presented in Section 8. In addition, platform gridded emission maps are displayed in Appendix B.

Table 1: 2021 final platform total annual GHG emissions (tons/year) by equipment type

Equipment Type	CO_2 (GWP = 1)	CH_4 (GWP = 25)	N_2O (GWP = 298)	CO_2-E
Amine Unit	0	0	-	0
Boiler/Heater/Burner	153,160	2.92	2.76	154,056
Cold Vent	1,038	***40,077**	0	1,002,969
Combustion Flare	462,900	2,297	7.89	522,674
Drilling Equipment	22,661	1.11	-	22,688
Engine – Diesel or Gasoline Engine	225,831	5.26	-	225,962
Engine – Natural Gas	935,394	4,436	-	1,046,301
Fugitives	-	28,273	-	706,820
Glycol Dehydrator	-	325	-	8,130
Losses from Flashing	28.6	1,231	-	30,807
Mud Degassing	1.22	131	-	3,283
Pneumatic Controller	139	6,346	-	158,800
Pneumatic Pump	265	12,139	-	303,730
Storage Tank	-	250	-	6,238
Turbine – Natural Gas, Diesel, or Dual Fuel	***4,133,918**	319	***111**	***4,175,051**
Total	5,935,335.82	95,833.29	121.65	8,367,509

Notes: * = highest emissions per pollutant; GHG = greenhouse gas; GWP = global warming potential; CO_2 = carbon dioxide; CH_4 = methane; N_2O = nitrous oxide; CO_2-E = carbon dioxide equivalent

Table 2: 2021 final platform total annual criteria pollutants and precursor emissions (tons/year) by equipment type

Equipment Type	NH_3	CO	Pb	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Amine Unit	-	-	-	-	-	-	-	-
Boiler/Heater/Burner	***4.09**	107	6.92E-04	240	2.46	2.42	0.771	6.98
Cold Vent	-	-	-	-	-	-	-	***12,570**
Combustion Flare	0.348	1,194	5.43E-05	271	6.2	6.2	23.7	7,518
Drilling Equipment	-	117	-	439	7.87	7.69	0.208	11.2
Engine – Diesel or Gasoline Engine	-	1,239	-	5,259	***260**	***253**	***241**	311
Engine – Natural Gas	-	***22,862**	-	***16,323**	74.4	74.4	5	463
Fugitives	-	-	-	-	-	-	-	7,162
Loading Operation	-	-	-	-	-	-	-	0
Losses from Flashing	-	-	-	-	-	-	-	55.4
Pneumatic Controller	-	-	-	-	-	-	-	892
Pneumatic Pump	-	-	-	-	-	-	-	1,592
Storage Tank	-	-	-	-	-	-	-	252
Turbine – Natural Gas, Diesel, or Dual Fuel	-	3,032	***0.00481**	12,128	72	72	29.1	78
Total	4.44	28,551	0.01	34,660	422.9	415.7	299.78	30,911.6

Notes: * = highest emissions per pollutant; NH_3 = ammonia; CO = carbon monoxide; Pb = lead; NO_x = nitrogen oxide; PM_{10} = particulate matter less than 10 microns; $PM_{2.5}$ = particulate matter less than 2.5 microns; SO_2 = sulfur dioxide; VOC = volatile organic compound

In addition, corrective action was taken on lease operations and non-platform facility sources such as drilling rigs. A total of 10 companies were identified to review reported drilling rig activity data (including move on and off dates, vessel power, and fuel sulfur content) and to complete lease operations data by adding or subtracting drilling rigs to the 2021 OCS AQS inventory. The Team incorporated the operators' revisions into the main 2021 database in OCS AQS. Table 3 provides a summary of the 2021 final lease operations total annual GHGs emissions, with the highest source contribution number identified for each GHG.

Table 4 provides a summary of the final lease operations 2021 total annual criteria pollutants and precursors in tons per year, with the highest source contribution number bolded per pollutant. Additional details regarding the 2021 final GHGs and criteria emissions are presented in Section 8. In addition, gridded emission maps for lease operations are displayed in Appendix C. Lastly, oil and gas vessels in transit (support vessels, survey vessels, and pipelaying vessels) are not included in this report unless they were used in installation of a facility or pipeline, and then they would have been included under lease operations during the installation and commissioning process.

Table 3: 2021 final lease operations total annual GHG emissions (tons/year) by source type

Source Type	CO_2	CH_4	N_2O	CO_2-E
Drilling rigs	**1,296,440**	**12.34**	**57.12**	**1,313,607**
Support vessels	99,439.76	4.791	0	99,546.4
Total	1,395,880	17.13	57.12	1,413,153

Notes: GHG = greenhouse gas; GWP = global warming potential; CO_2 = carbon dioxide; CH_4 = methane; N_2O = nitrous oxide; CO_2-E = carbon dioxide equivalent

Table 4: 2021 final lease operations total annual criteria pollutants and precursor emissions (tons/year) by source type

Source Type	CO	NOx	PM_{10}	$PM_{2.5}$	SO_2	VOC	NH_3	Pb
Drilling rigs	**4,597.11**	**18,974.13**	**416.1**	**401.76**	**12**	**237.75**	**5.53**	**5.53E-02**
Support vessels	512.57	1,932.78	35.47	29.84	7	49.25	0	0
Total	5,119.68	20,906.91	451.57	431.6	19	287	5.53	5.53E-02

Notes: NH_3 = ammonia; CO = carbon monoxide; Pb = lead; NO_x = nitrogen oxide; PM_{10} = particulate matter less than 10 microns; $PM_{2.5}$ = particulate matter less than 2.5 microns; SO_2 = sulfur dioxide; VOC = volatile organic compound

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Units of Measure

Units	Description
%	percent
bbl	U.S. barrel (42 gallons)
Btu	British thermal unit
day	24-hour period
deg F	degree Fahrenheit
ft	foot
g	gram
gal	gallon
HP	horsepower
hr	hour
kW	kilowatt
lb	pound
MMBtu	million British thermal unit
mol	mole
month	calendar month
Mscf	thousand standard cubic feet
MW	molecular weight
ppm	parts per million
ppmv	parts per million volume
psia	pounds per square inch, atmosphere
psig	pounds per square inch, gauge
scf	standard cubic feet
tons	short tons
wt%	percent of total weight
year	calendar year

List of Acronyms and Abbreviations

Short Form	Long Form
AMI	amine unit(s)
API	American Petroleum Institute
BOEM	Bureau of Ocean Energy Management
BOI	boiler/heater/burner
BSEE	Bureau of Safety and Environmental Enforcement
BTEX	benzene, toluene, ethylbenzene, and xylene
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-E	carbon dioxide equivalent
DIE	engine – diesel or gasoline engine
DRI	drilling equipment
EF	emission factor
ERG	Eastern Research Group
FLA	combustion flare
FUG	fugitives
GHG	greenhouse gas
GLY	glycol dehydrator
GOADS	Gulfwide Offshore Activities Data System
GOM	Gulf of Mexico
GOR	gas-to-oil ratio
GWP	global warming potential
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
IPCC	Intergovernmental Panel on Climate Change
LOA	loading operation
LOS	losses from flashing
MS	Microsoft
MUD	mud degassing
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NGE	engine – natural gas
NGT	turbine – natural gas, diesel, or dual fuel
NH_3	ammonia
NO_x	nitrogen oxide
NTL	Notice to Lessees
OCS AQS	Outer Continental Shelf Air Quality System
OCS	Outer Continental Shelf
ONRE	operating not reporting emissions
OP	operating
OPD	official protraction diagram

Short Form	Long Form
PAH	polycyclic aromatic hydrocarbon
Pb	lead
PM_{10}	particulate matter less than 10 microns
$PM_{2.5}$	particulate matter less than 2.5 microns
PNE	pneumatic pump
PRE	pneumatic controller
PS	permanently shut down
QA	quality assurance
QC	quality control
RELINQ	relinquished
ROW	right-of-way
SO_2	sulfur dioxide
SO_x	sulfur oxide
SOP	Suspension of Production
STO	storage tank
TERMIN	terminated
THC	total hydrocarbons
TIMS	Technical Information Management System
TS	temporarily shut down
USEPA	U.S. Environmental Protection Agency
VEN	cold vent
VOC	volatile organic compound
VR	vented remotely

1 Introduction

The Bureau of Ocean Energy Management (BOEM) is required under the Outer Continental Shelf (OCS) Lands Act (OCSLA) (43 U.S.C. § 1334(a)(8)) to comply with the National Ambient Air Quality Standards (NAAQS) to the extent that OCS oil and gas activities significantly affect the air quality of any state. BOEM's Gulf of Mexico (GOM) Regional Office prepares Gulfwide emissions inventories and has completed inventories for 2000, 2005, 2008, 2011, 2014, and 2017. BOEM collects emissions inventories following U.S. Environmental Protection Agency's (USEPA's) three-year schedule; however, the 2020 inventory was delayed to 2021 as BOEM was developing a modern web application to replace the legacy Gulfwide Offshore Activity Data System (GOADS). In October 2020, BOEM issued a Notice to Lessees (NTL) No. 2020-N03[1] requesting that lessees and operators with facilities (as defined in 30 CFR 550.302) collect and report activity information and emissions covering the period January 1, 2021, to December 31, 2021. Lessees and operators were required to submit their emissions inventory data by April 22, 2022.

Figure 1 shows the OCS planning areas (offshore white and blue areas), including the Western, Central, and Eastern GOM Planning Areas in the GOM Region and multiple planning areas for the Alaska, Pacific, and Atlantic Regions. The blue shaded areas are under BOEM air quality jurisdiction (Western and Central Planning Area in the GOM Region and Beaufort and Chukchi Sea Planning Areas with a portion of the Hope Basin Planning Area in the Alaska Region); in these areas, operators are required to submit emissions data to BOEM using the Outer Continental Shelf Air Quality System (OCS AQS) tool. For the 2021 inventory, only the operators in the GOM Region were required to submit their emissions data because no emissions sources were operating in the Alaska Region.

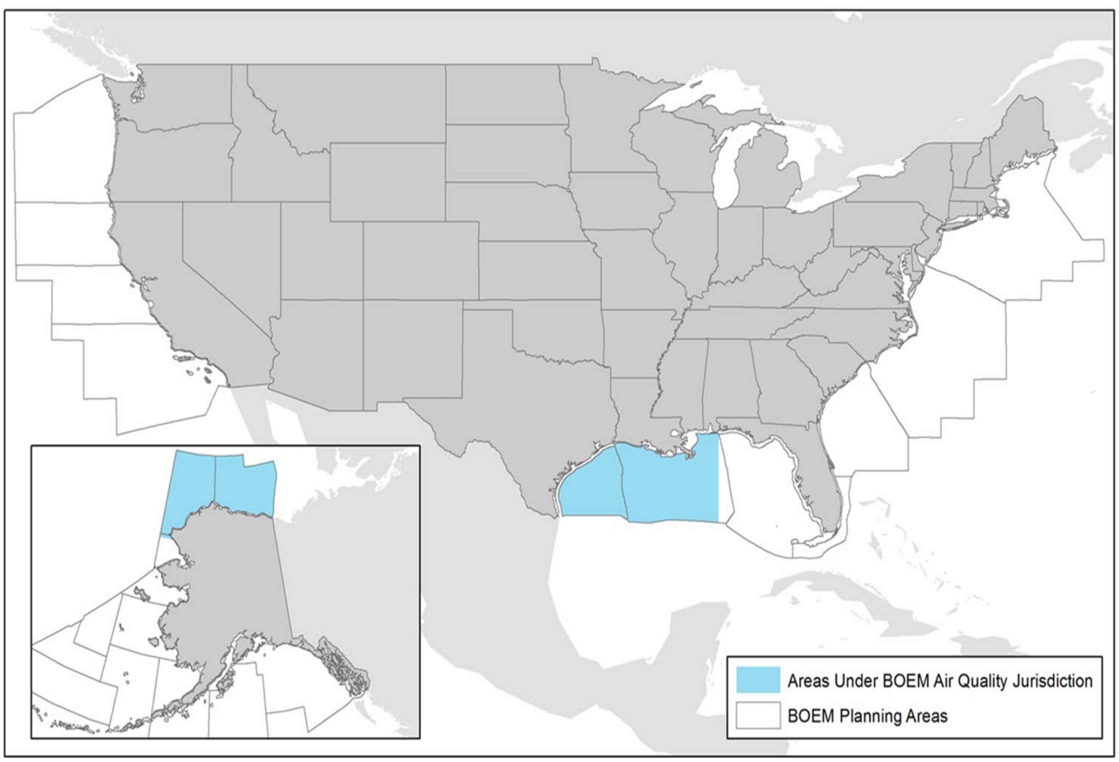


Figure 1: Map of project study area

[1] See the NTL at https://www.boem.gov/sites/default/files/documents/about-boem/NTL-2020-N03.pdf

1.1 Study Objectives

The Xator-Lakes Team ("the Team") conducted this study in support of BOEM under contract number 140E0119C0006. The purpose and scope of the study comprised four broadly defined parts.

First, the Team performed forensic-level quality assurance (QA)/quality control (QC) analysis of the 2021 draft platforms emissions inventory by examining emissions from all equipment types and identified discrepancies, errors, and outliers that require corrective action (Sections 4 and 7). The effort included following up with operators to request verification or corrective actions to their draft submittals and coordinating with BOEM to ensure that all responses, including corrective actions, were completed in a timely and acceptable manner so the 2021 emissions inventory could be finalized. The previous QA/QC work done by Eastern Research Group, Inc. (ERG) for the 2017 inventory served to guide this effort (Wilson et al. 2019), as well as the more recent review of the same data completed by the Argonne National Laboratory under contract M21PG00021. This analysis ensures the 2021 final emissions inventory data is of the best possible quality.

Second, the Team conducted an emission factor (EF) comparison between the 2017 and 2021 inventories and a review of USEPA's currently recommended EFs to ensure the 2021 inventory was prepared using the latest information available (Section 5). This comparison was expected to provide some insight into whether increases/decreases in the reported emissions are due to changes in EFs or a combination of other dynamics, including changes in operator activity, addition of new platforms and lease operations, decommissioned platforms, and changes in the emissions calculation methods (Sections 3 and 5).

Third, the study covered QA/QC of drilling rig activity (non-platform) emissions by comparing the 2021 Field Operations Drilling Rig Report generated from the Bureau of Safety and Environmental Enforcement's (BSEE's) eWell database with drilling rig emissions reported in the OCS AQS 2021 inventory under the Lease Operations[2] category (Section 9). Investigation of reported drilling rig emissions is important as the 2021 emissions inventory was the first year that operators were required to report emissions from these activities.

Fourth, based on the QA/QC effort, the Team finalized the 2021 platform emissions data in OCS AQS and compared the data with 2017 final platform emissions (Section 8). The data will be published on BOEM's website as an MS Access file, like past final inventory data. Appendix B and C provide geographical distribution of the 2021 emissions for platforms and lease operations, respectively. BOEM will publish the Year 2021 drilling rig data (lease operations) on its website as an MS Access file, like past final inventory data.

[2] "Non-platform" sources in GOADS are currently labeled as "lease operation" in OCS AQS.

2 Overview of Data Collection Using OCS AQS

This section summarizes the data collection process used for the 2021 emissions inventory. As already noted, BOEM used the newly implemented OCS AQS to collect and manage the activity and emissions data from oil and gas operators for the 2021 inventory. OCS AQS is a comprehensive web-based software solution which replaced the legacy, GOADS in 2020. OCS AQS allows oil and gas operators to enter their facility source specific activity data from a secure web portal, guiding them through the data input process, performing automatic range checks, and automatically calculating the emissions based on operator input and the USEPA's EFs and calculations. The system is easily accessible from a web browser and greatly simplifies the work of collecting activity and emissions data from all oil and gas operators.

2.1 Static Data

As a baseline for the 2021 inventory effort, the Team first captured all static information (e.g., complex and structure ID of each facility, coordinates of the facility location, equipment types, etc.) from the 2017 inventory and imported the static data in OCS AQS. Operators could then input their 2021 activity data (e.g., fuel usage, volume throughput, etc.) for each of their facilities without having to re-enter the static information. Significant effort was expended to ensure that missing facilities (e.g., those that came online since the 2017 effort) were added to the system and decommissioned facilities were appropriately deactivated and archived (see Section 4.4).

Figure 2 shows the main dashboard of OCS AQS, which provides an overview of the inventory data from the 2021 effort. For the 2021 effort, there are 1,738 platforms (including operating and non-operating) listed in the 2021 OCS AQS draft inventory; these platforms are owned by 64 companies. Of these platforms, 1,723 platforms have successfully submitted their calculated 2021 emissions. The remaining 15 facilities (operated by five companies) failed to submit their inventories before the submittal deadline.

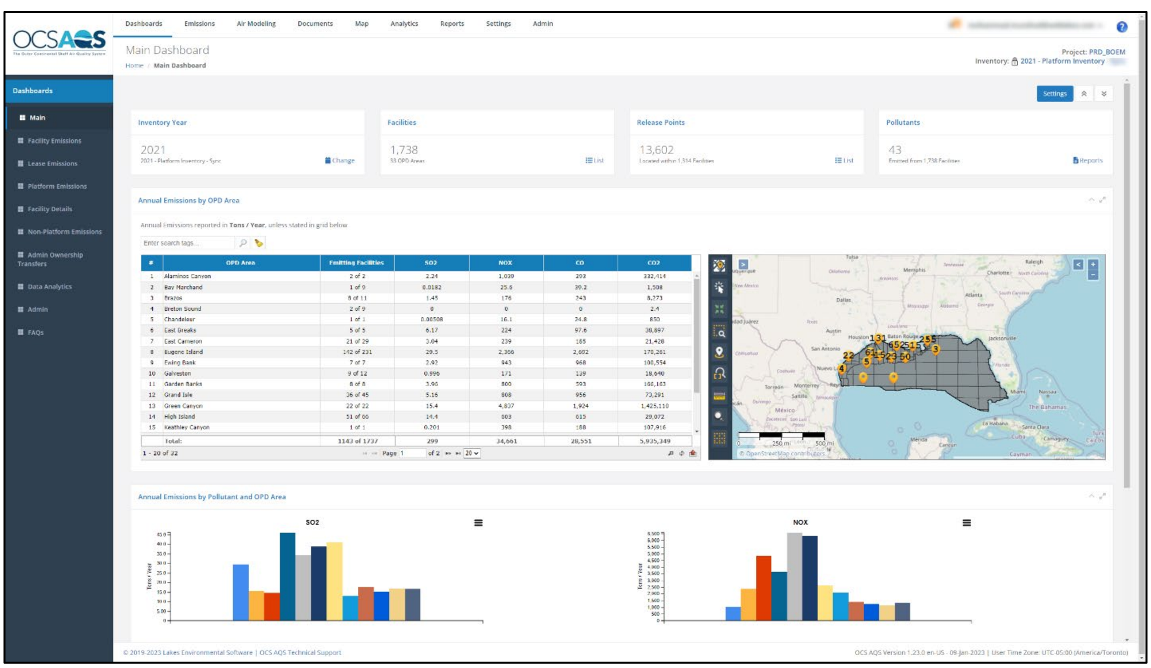


Figure 2: Main OCS AQS dashboard

2.2 Operator Input and Submission

Oil and gas operators were provided with OCS AQS accounts, which they could access securely from a web browser. OCS AQS guides operators by the user interface to input the required activity data by equipment source type for the facilities. OCS AQS automatically calculates the emissions based on the operator input and USEPA's EFs and calculations. OCS AQS also provides various other features and tools to assist them in the analysis of their data before submittal, such as the ability to generate reports and maps. To instruct the operators with their use of the new OCS AQS system, the Team conducted virtual training classes prior to the operator portal being opened, and the *OCS AQS Operator User Manual* was published on the BOEM website at https://www.boem.gov/environment/environmental-studies/2021-ocs-emissions-inventory (Thé et al. 2022).

After the operators completed the input process and passed the baseline QA/QC (Figure 3), they were able to submit their inventory to BOEM directly from the system. BOEM administrators then could view the submitted data from their OCS AQS accounts. The Team performed the post-submittal QA/QC to ensure data quality as detailed in this report.

2.3 Data Collected

As defined per the 30 CFR 550.302, *Definitions Concerning Air Quality*, operators were required to enter emissions inventory data for all sources that meet the following facility definition:

> *Facility* means any installation or device permanently or temporarily attached to the seabed which is used for exploration, development, and production activities for oil, gas, or sulfur and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be a single facility if the installations or devices are directly related to the production of oil, gas, or sulfur at a single site. Any vessel used to transfer production from an offshore facility shall be considered part of the facility while physically attached to it.

Operators and lessees were not required to report emissions from sources that do not constitute a "*facility*" as defined above. For example, supply or crew transport vessels are not facilities as defined in the regulation but drilling rigs or vessels such as mobile offshore drilling units were required to report emissions when they are connected either to the seabed or to a facility. In instances where drilling activities are connected to a facility, operators were requested to report emissions as part of the platform (or facility as defined by complex-structure ID) in OCS AQS. Approved drilling activities not connected to a platform were required to report emissions as part of lease operations as designated by the BOEM Lease Number in OCS AQS.

Examples of required information included the following:

- Facility equipment
- Source coordinates
- Physical source characteristics (and stack information)
- Fuel type and composition
- Fuel usage
- Days and hours of operation
- Volumes vented and flared

OCS AQS identified mandatory data input by shading the data entry boxes in green as displayed in the *OCS AQS Operator User Manual* (Thé et al. 2022) and Figure 4. Operators were allowed to provide additional information, including equipment details and other supporting information to document mandatory values.

2.4 Process Flowchart

Figure 3 provides a flowchart describing the overall process for 2021 emissions inventory data collection and finalization, which ends with the publication of the 2021 final inventory data by BOEM. After the QA/QC review process is completed and all required corrective actions are taken by operators to complete their inventories, the final emissions inventory report will be published on BOEM's website (https://www.boem.gov/environment/environmental-studies/2021-ocs-emissions-inventory). BOEM also will post an MS Access database file that contains the final emissions data.

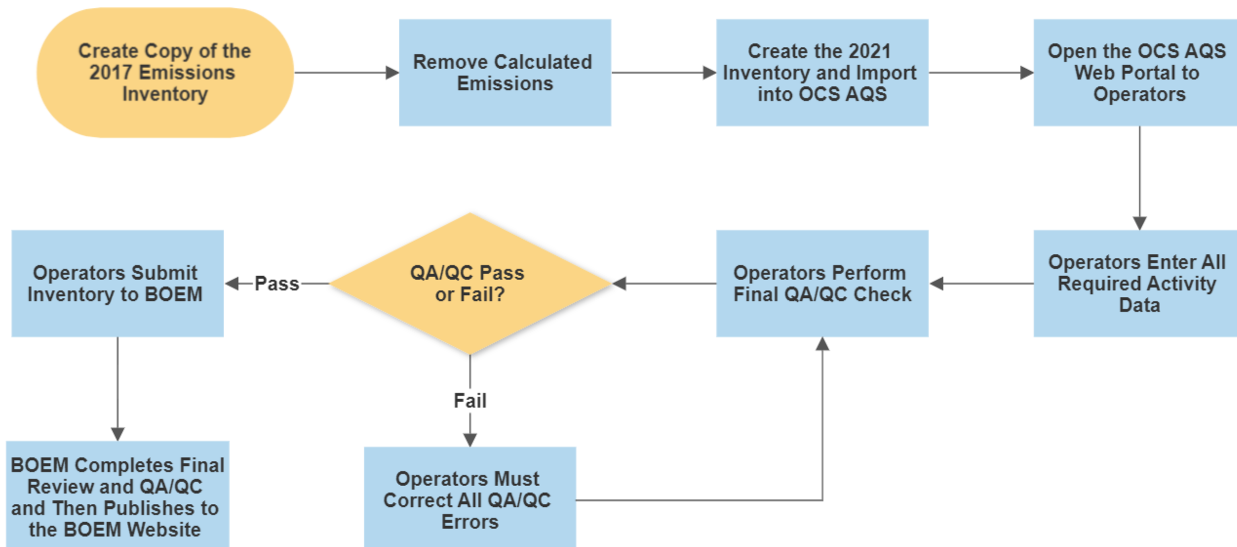


Figure 3: 2021 emissions inventory process

3 Calculation Methods and EFs (Platform Sources)

3.1 Introduction

This section describes the calculation methods and EFs used in the 2021 emissions inventory effort to estimate emissions from platform sources of oil and gas operations in the GOM OCS (west of 87° 30' West longitude) from facilities with a unique BOEM Complex and Structure ID number. The descriptions reflect any updates made to the 2017 calculation methods and EFs. To see what changes were made to the 2017 calculation methods and EFs, please refer to Section 8. Emissions from lease operations are discussed in Section 9.

As already described, OCS AQS is a secure web-based system that allows operators to input their activity data for each equipment source type on a facility directly through the web interface (such as fuel used or volume vented or flared). The system uses these input data and USEPA's EFs and calculation methods to calculate the emissions automatically. All emissions calculators programmed into OCS AQS were validated by the Team prior to the final deployment into the production environment where operators could access the system.

In the input process, OCS AQS guided the operators through its user-friendly interface and online context-sensitive help. For example, Figure 4 shows the Data Requests page for the boiler, heater, and burner units. Operators provided data in the mandatory fields indicated by the green boxes (Total Fuel Usage, Fuel Sulfur Content, and Emissions Destination in this example) on the top of the Data Requests page. Operators had the option of populating white fields (listed as other information).

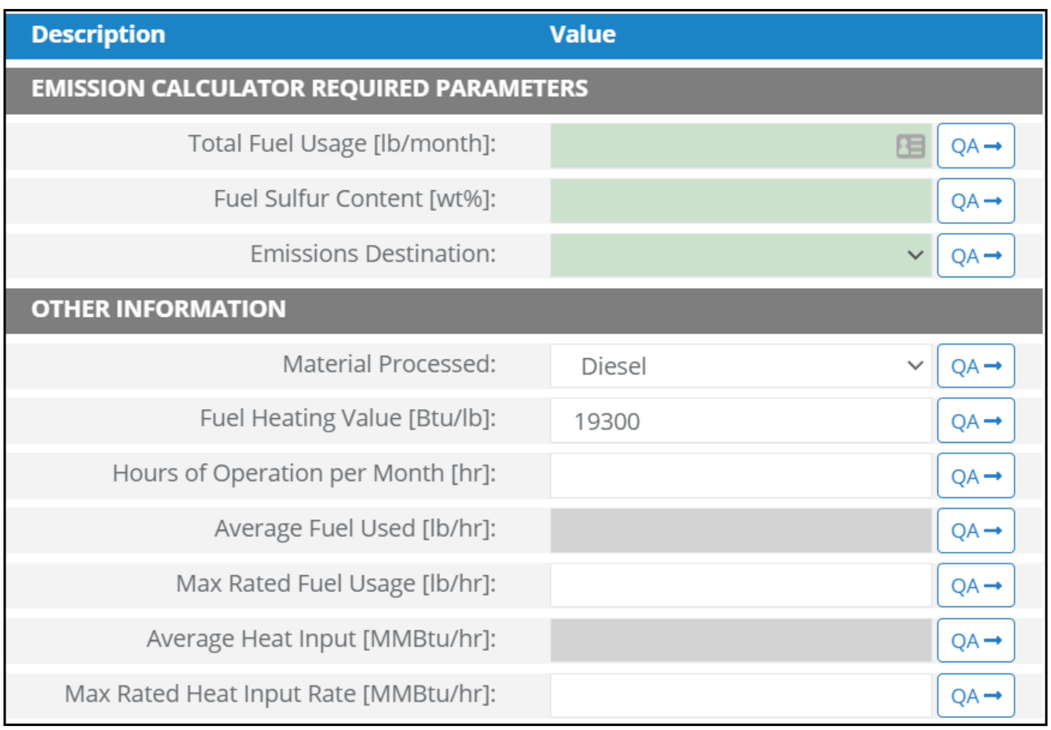


Figure 4: An example of the Data Requests page for boiler, heater, and burner units in OCS AQS for operator input showing the mandatory required input fields on top highlighted in green

In addition, operators had the option to provide reduction efficiencies for certain pollutants in the Control Requests page. Figure 5 shows the Controls Requests page for the boiler, heater, and burner units.

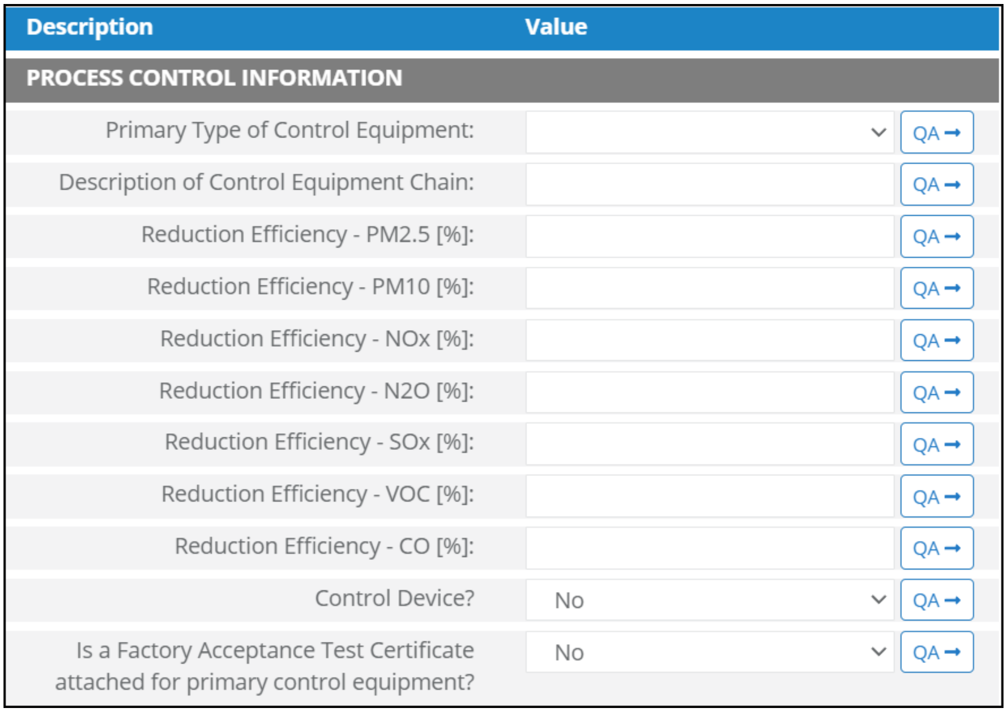


Figure 5: An example of the Control Requests page for boiler, heater, and burner units in OCS AQS for optional input on reduction efficiencies

> ***NOTE:*** In this section, input data that were **required** from the operators to calculate the emissions are indicated by the **bold type** (corresponding to the mandatory green fields shown in the Data Requests page shown in Figure 4). The Emissions Destination field is not used directly in the emissions calculations but must be defined to designate where equipment emissions are released into the atmosphere. The designation of the release point is mandatory as it is required to accurately characterize the point of release in air dispersion modeling. A note is provided in this section to indicate when an operator is allowed to provide reduction efficiencies for a pollutant (Figure 5). For all calculation methods in OCS AQS that are described in this section, Data Requests pages like Figure 4 and Control Requests pages like Figure 5 can be found in Appendix A of the *OCS AQS Operator User Manual* (Thé et al. 2022).

After operators entered all parameters and initial QA/QC was completed, OCS AQS executed the appropriate calculations to estimate the emissions data.

3.2 Emissions Calculation Methods

A complete description of the oil and gas exploration and production equipment types discussed can be found on the USEPA AP-42 website (https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors) and in the *OCS AQS Operator User Manual*. Table 5 provides a summary of references documenting the primary source of the equation presented in this section. Table 6 provides a summary of references document the primary source of EFs used in OCS AQS to complete the 2021 emission inventory (see also Appendix D). Additional parameters provided in the Section 3 tables are from the *Year 2017 Emissions Inventory Study* (Wilson et al. 2019) and USEPA AP-42.

Table 5: 2021 emissions inventory equation references

#	Emission Estimation Procedures	Reference
1	Amine Units	American Petroleum Institute (1999)
2	Boilers, Heaters, and Burners	Wilson et al. (2019)
3	Diesel and Gasoline Engines	Wilson et al. (2019)
4	Drilling Equipment	Wilson et al. (2019)
5	Combustion Flares	Wilson et al. (2019)
6	Fugitive Sources	Wilson et al. (2019)
7	Glycol Dehydrators	URS Radian (2019)
8	Loading Operations	Wilson et al. (2019)
9	Losses from Flashing	Wilson et al. (2019)
10	Mud Degassing	Wilson et al. (2019)
11	Natural Gas Engines	Wilson et al. (2019)
12	Natural Gas, Diesel, and Dual-Fuel Turbines	Wilson et al. (2019)
13	Pneumatic Pumps	Wilson et al. (2019)
14	Pneumatic Controllers	Wilson et al. (2019)
15	Storage Tanks	USEPA (2022)
16	Cold Vents	Wilson et al. (2019)

Table 6: 2021 EF references

#	Emission Estimation Procedures	Reference
1	Amine Units	American Petroleum Institute (1999)
2	Boilers, Heaters, and Burners	USEPA (2022)
3	Diesel and Gasoline Engines	USEPA (2022)
4	Drilling Equipment	USEPA (2022)
5	Combustion Flares	USEPA (2022)
6	Fugitive Sources	Wilson et al. (2019)
7	Glycol Dehydrators	URS Radian (2019)
8	Loading Operations	Wilson et al. (2019)
9	Losses from Flashing	Wilson et al. (2019)
10	Mud Degassing	Wilson et al. (2019)
11	Natural Gas Engines	USEPA (2022)
12	Natural Gas, Diesel, and Dual-Fuel Turbines	USEPA (2022)
13	Pneumatic Pumps	Wilson et al. (2019)
14	Pneumatic Controllers	Wilson et al. (2019)
15	Storage Tanks	USEPA (2022)
16	Cold Vents	Wilson et al. (2019)

The following subsections describe the emissions equations used to calculate the 2021 emissions inventory.

3.2.1 Amine Units (AMI)

OCS AQS provides a calculator for AMI. Hourly emissions from AMI are calculated externally to OCS AQS using the American Petroleum Institute (API) PUBL 4679 Amine Unit Emissions Model AMINECalc Version 1.0. The emissions data must be imported to OCS AQS using the Amine Emission Rates Import tool available within OCS AQS. The operator is required to provide the **hourly emissions data (lb/hr)** as well as the **hours of operation per month (hr/month)**. Emissions are then calculated as follows:

$$E = E_{hr} \times t \qquad (Eq. 1)$$

where:

E = Emissions (lb/month)
E_{hr} **= Hourly emissions of AMI (lb/hr)**
t **= Hours of operation per month (hr/month)**

3.2.2 Glycol Dehydrators (GLY)

OCS AQS provides a calculator for glycol dehydrators (GLY-000). Hourly emissions from glycol dehydrators are calculated externally to OCS AQS using the GRI-GLYCalc™ Software Version 4.0. The emissions data must be imported to OCS AQS using the Glycol Emission Rates Import tool available within OCS AQS. The operator is required to provide the **hourly emissions data (lb/hr)** as well as the **hours of operation per month (hr/month)**. Emissions are then calculated as follows:

$$E = E_{hr} \times t \qquad (Eq. 2)$$

where:

E = Emissions (lb/month)
E_{hr} **= Hourly emissions of glycol dehydrators (lb/hr)**
t **= Hours of operation per month (hr/month)**

3.2.3 Boilers, Heaters, and Burners with Control Reductions (BOI)

OCS AQS provides three calculators for boilers, heaters, and burners, based on the type of fuel. These calculators are designated as BOI-M01R (Diesel), BOI-M02R (Waste Oil), and BOI-M03R (Natural Gas, Process Gas, or Waste Gas).

3.2.3.1 Units Powered by Diesel (BOI-M01R)

For boiler, heater, and burner units powered by diesel, emissions are calculated as follows:

$$E = EF \times 0.001 \times \frac{U}{7.1\ \mathrm{lb/gal}} \qquad (Eq. 3)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/10^3 gal)
U = **Total fuel usage (lb/month)**
S = **Fuel sulfur content (wt %)** – This factor is not shown in the formula above but is a required field in OCS AQS (as indicated by the bold type here) and is used to obtain the SO_2 EFs.

Table 7 shows the EFs for units powered by diesel.

Table 7: EFs for boilers, heaters, and burners powered by diesel

Pollutant	EF (lb/ 10^3 gal)
Volatile organic compound (VOC)†	0.2
Lead (Pb)	1.22E-03
Sulfur dioxide (SO_2)†	142 × S
Nitrogen oxide (NO_x)†	24
Particulate matter less than 2.5 microns ($PM_{2.5}$)†	0.25
Particulate matter less than 10 microns (PM_{10})†	1
Ammonia (NH_3)	0.8
Carbon monoxide (CO)†	5
Nitrous oxide (N_2O)†	0.26
Methane (CH_4)	0.05
Carbon dioxide (CO_2)	22,300
Arsenic	1.32E-03
Benzene	2.14E-04
Beryllium	2.78E-05
Cadmium	3.98E-04
Chromium VI	2.48E-04
Chromium III	5.97E-04
Ethylbenzene	6.36E-05
Formaldehyde	0.033
Mercury	1.13E-04
Toluene	6.2E-03
Xylenes	1.09E-04

Note: † Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) on a separate page (Control Requests page) in OCS AQS.

3.2.3.2 Units Powered by Waste Oil (BOI-M02R)

For boiler, heater, and burner units powered by waste oil, emissions are calculated as follows:

$$E = EF \times 0.001 \times \frac{U}{7.1\ \text{lb/gal}} \qquad (Eq. 4)$$

where:

E = Emissions (lb/month)

EF = Emission factor (lb/10^3 gal)

U = **Total fuel usage (lb/month)**

S = **Fuel sulfur content (wt %)** – This factor is not shown in the formula above but is a required field in OCS AQS and is used to obtain certain EFs.

Table 8 shows the EFs for units powered by waste oil.

Table 8: EFs for boilers, heaters, and burners powered by waste oil

Pollutant	EF (lb/ 10^3 gal)
VOC†	0.28
Pb	1.51E-03
SO_2†	$157 \times S$
NO_x†	47
$PM_{2.5}$†	$5.23 \times S + 1.73$
PM_{10}†	$9.19 \times S + 3.22$
NH_3	0.8
CO†	5
N_2O†	0.53
CH_4	1
CO_2	24,400
Arsenic	1.32E-03
Benzene	2.14E-04
Beryllium	2.78E-05
Cadmium	3.98E-04
Chromium VI	2.48E-04
Chromium III	5.97E-04
Ethylbenzene	6.36E-05
Formaldehyde	0.033
Mercury	1.13E-04
Toluene	6.2E-03
Xylenes	1.09E-04

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.3.3 Units Powered by Natural Gas, Process Gas, or Waste Gas (BOI-M03R)

For boiler, heater, and burner units powered by natural gas, process gas, or waste gas, emissions are calculated as follows:

$$E = EF \times 0.001 \times U \qquad (Eq. 5)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMscf)
U = **Total fuel usage (MSCF/month)**

Table 9 shows the EFs for units powered by natural gas, process gas, or waste gas.

Table 9: EFs for boilers, heaters, and burners powered by gas

Pollutant	EF (lb/MMscf)
VOC†	5.5
Pb	5E-04
SO_2†	0.6
NO_x†	190
$PM_{2.5}$†	1.9
PM_{10}†	1.9
NH_3	3.2
CO†	84
N_2O†	2.2
CH_4	2.3
CO_2	120,000
Arsenic	2E-04
Benzene	2.1E-03
Beryllium	1.2E-05
Cadmium	1.1E-03
Chromium III	1.34E-03
Chromium VI	5.60E-05
Formaldehyde	0.075
Hexane	1.8
Mercury	2.6E-04
Toluene	3.40E-03

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.4 Diesel and Gasoline Engines (DIE)

OCS AQS provides three calculators for diesel and gasoline engines. These calculators are designated as DIE-M01R (gasoline engines), DIE-M02R (diesel engines with max HP < 600), and DIE-M03R (diesel engines with max HP ≥ 600).

3.2.4.1 Gasoline Engines (DIE-M01R)

For gasoline engines, emissions are calculated as follows:

$$E = EF \times 10^{-6} \times U \times 6.17 \frac{\text{lb}}{\text{gal}} \times H \qquad (Eq. 6)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
U = **Total fuel usage (gal/month)**
H = **Fuel heating value (Btu/lb)**

Table 10 shows the EFs for gasoline engines.

Table 10: EFs for gasoline engines

Pollutant	EF (lb/MMBtu)
VOC†	3.03
SO_2†	0.084
NO_x†	1.63
$PM_{2.5}$†	0.1
PM_{10}†	0.1
CO†	0.99
CO_2	154

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.4.2 Diesel Engines with Max HP < 600 (DIE-M02R)

For diesel engines with max HP < 600, emissions are calculated as follows:

$$E = EF \times 10^{-6} \times U \times 7.1 \frac{\text{lb}}{\text{gal}} \times H \qquad (Eq. 7)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
U = **Total fuel usage (gal/month)**
H = **Fuel heating value (Btu/lb)**

Table 11 shows the EFs for diesel engines with max HP < 600.

Table 11: EFs for diesel engines with max HP < 600

Pollutant	EF (lb/MMBtu)
VOC†	0.36
SO_2†	0.29
NO_x†	4.41
$PM_{2.5}$†	0.31
PM_{10}†	0.31
CO†	0.95
CO_2	164
Acetaldehyde	7.67E-04
Benzene	9.33E-04
Formaldehyde	1.18E-03
Polycyclic aromatic hydrocarbon (PAH)	1.68E-04
Toluene	4.09E-04
Xylenes	2.85E-04

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.4.3 Diesel Engines with Max HP ≥ 600 (DIE-M03R)

For diesel engines with max HP ≥ 600, emissions are calculated as follows:

$$E = EF \times 10^{-6} \times U \times 7.1 \frac{\text{lb}}{\text{gal}} \times H \qquad (Eq. 8)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
U = **Total fuel usage (gal/month)**
H = **Fuel heating value (Btu/lb)**
S = **Fuel sulfur content (wt %)** – This factor is not shown in the formula above but is a required field in OCS AQS and is used to obtain certain EFs.

Table 12 shows the EFs for diesel engines with max HP ≥ 600.

Table 12: EFs for diesel engines with max HP ≥ 600

Pollutant	EF (lb/MMBtu)
VOC†	0.08
SO_2†	$1.01 \times S$
NO_x†	3.2
$PM_{2.5}$†	0.0479
PM_{10}†	0.0573
CO†	0.85
CH_4	8E-03
CO_2	165
Acetaldehyde	2.52E-05
Benzene	7.76E-04
Formaldehyde	7.89E-05
PAH	2.12E-04
Toluene	2.81E-04
Xylenes	1.93E-04

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.5 Drilling Equipment with Control Reduction (DRI)

OCS AQS provides three calculators for DRI, based on the type of fuel. These calculators are designated as DRI-M01R (Gasoline), DRI-M02R (Diesel), and DRI-M03R (Natural Gas).

3.2.5.1 Units Powered by Gasoline (DRI-M01R)

For gasoline-powered DRI, emissions are calculated as follows:

$$E = EF \times 10^{-6} \times U \times 6.17 \frac{\text{lb}}{\text{gal}} \times 20{,}300 \frac{\text{Btu}}{\text{lb}} \qquad (Eq. 9)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
U = **Total fuel usage (gal/month)**

Table 13 shows the EFs for units powered by gasoline.

Table 13: EFs for drilling equipment powered by gasoline

Pollutant	EF (lb/MMBtu)
VOC†	3.03
SO_2†	0.084
NO_x†	1.63
$PM_{2.5}$†	0.1
PM_{10}†	0.1
CO†	0.99
CO_2	154

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.5.2 Units Powered by Diesel (DRI-M02R)

For diesel-powered DRI, emissions are calculated as follows:

$$E = EF \times 10^{-6} \times U \times 7.1 \frac{\text{lb}}{\text{gal}} \times 19{,}300 \frac{\text{Btu}}{\text{lb}} \qquad (Eq. 10)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
U = **Total fuel usage (gal/month)**
S = **Fuel sulfur content (wt %)** – This factor is not shown in the formula above but is a required field in OCS AQS and is used to obtain certain EFs.

Table 14 shows the EFs for units powered by diesel.

Table 14: EFs for drilling equipment powered by diesel

Pollutant	EF (lb/MMBtu)
VOC†	0.0819
SO_2†	$1.01 \times S$
NO_x†	3.2
$PM_{2.5}$†	0.056
PM_{10}†	0.0573
CH_4	8.1E-03
CO†	0.85

Pollutant	EF (lb/MMBtu)
CO_2	165
Acetaldehyde	2.52E-05
Benzene	7.76E-04
Formaldehyde	7.89E-05
PAH	2.12E-04
Toluene	2.81E-04
Xylenes	1.93E-04

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.5.3 Units Powered by Natural Gas (DRI-M03R)

For DRI powered by natural gas, emissions are calculated as follows:

$$E = EF \times U \times 0.001 \qquad (Eq. 11)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMscf)
U = **Total fuel usage (Mscf/month)**

Table 15 shows the EFs for units powered by natural gas.

Table 15: EFs for drilling equipment powered by natural gas

Pollutant	EF (lb/MMscf)
VOC†	75.3
SO_2†	0.6
NO_x†	2,467.5
$PM_{2.5}$†	4.9
PM_{10}†	4.9
CO†	2,127.3
CH_4	755
CO_2	112,200
Acetaldehyde	5.86
Benzene	1.06
Ethylbenzene	0.03
Formaldehyde	38.54
PAH	0.09
Toluene	0.51
Xylenes	0.2

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.6 Combustion Flares and Flare Pilots (FLA)

OCS AQS provides two calculators for FLA—one for the flare and the other for the flare pilot. These calculators are designated as FLA-M01 (combustion flare) and FLA-M02 (combustion flare–pilot).

3.2.6.1 Combustion Flares (FLA-M01)

For combustion flares, emissions are calculated as follows for the pollutants listed in Table 16:

$$E = V \times H \times EF \times 0.001 \quad \text{(Eq. 12)}$$

where:

E = Emissions (lb/month)
V = **Total volume of gas flared, not including pilot (Mscf)**
H = **Flare gas heating value (Btu/scf)**
EF = Emission factor (lb/MMBtu), which can depend on **smoke conditions**, provided as operator input (see below)

Table 16 shows the EFs for combustion flares.

Table 16: EFs for combustion flares

Pollutant	EF (lb/MMBtu)
NO_x	0.068
$PM_{2.5}$, PM_{10} **no smoke**	0.0
$PM_{2.5}$, PM_{10} **light smoke**	2E-03
$PM_{2.5}$, PM_{10} **medium smoke**	0.01
$PM_{2.5}$, PM_{10} **heavy smoke**	0.02
CO	0.31
N_2O	2E-03
CO_2	117.65
Acetaldehyde	0.05519
Benzene	1.59E-03
Ethylbenzene	9E-05
Formaldehyde	0.08302
Hexane	7.48E-03
Toluene	1.42E-03
2,2,4 Trimethylpentane	2.11E-03
Xylenes	4E-04

Flare emissions for **SO_2**, **VOC**, and **CH_4** are calculated using different formulation, as described below. Among other differences, each requires the use of its **molecular weight** in lb/lb-mol, as shown.

For **SO_2**, which has a molecular weight of 64 lb/lb-mol, emissions are calculated as follows:

$$E_{SO_2} = \frac{Eff}{100} \times \frac{10^{-6}}{\text{ppm}} \times \frac{64 \text{ lb/lb-mol}}{379.4 \frac{\text{scf}}{\text{lb-mol}}} \times 1{,}000 \times \mathrm{V} \times C_{H_2S} \quad \text{(Eq. 13)}$$

where:

E_{SO_2} = SO_2 emissions (lb/month)
Eff = **Combustion efficiency of the flare (%)**
V = **Total volume of gas flared, not including pilot (Mscf)**
C_{H_2S} = **Concentration of H_2S in the flare gas (ppm)**

For **VOC**, emissions are calculated as follows:

$$E_{VOC} = V \times \left(1 - \frac{Eff}{100}\right) \times \frac{m_{VOC}\ \text{lb/lb-mol}}{379.4\,\frac{\text{scf}}{\text{lb-mol}}} \times 1{,}000 \qquad \text{(Eq. 14)}$$

where:

E_{VOC} = VOC emissions (lb/month)
Eff = **Combustion efficiency of the flare (%)**
V = **Total volume of gas flared, not including pilot (Mscf)**
m_{VOC} = The mole weight of VOC - this is automatically calculated in OCS AQS from the sales gas data

For **CH_4**, which has a molecular weight of 16.04 lb/lb-mol, emissions are calculated as follows:

$$E_{CH_4} = V \times \left(1 - \frac{Eff}{100}\right) \times \frac{16.04\,\text{lb/lb-mol}}{379.4\,\frac{\text{scf}}{\text{lb-mol}}} \times 1{,}000 \qquad \text{(Eq. 15)}$$

where:

E_{CH_4} = CH_4 emissions (lb/month)
Eff = **Combustion efficiency of the flare (%)**
V = **Total volume of gas flared, not including pilot (Mscf)**

3.2.6.2 Flare Pilot (FLA-M02)

Emissions from flare pilot are calculated as follows:

$$E = P \times D \times EF \times 0.001 \qquad \text{(Eq. 16)}$$

where:

E = Emissions (lb/month)
P = **Pilot feed rate (Mscf/day)**
D = **Number of days in month (day)**
EF = Emission factor (lb/MMscf)

Table 17 shows the EFs for flare pilot.

Table 17: EFs for flare pilot

Pollutant	EF (lb/MMscf)
VOC	5.5
Pb	5E-04
NO_x	100
$PM_{2.5}$	1.9
PM_{10}	1.9
NH_3	3.2
SO_2	0.6
CO	84
N_2O	2.2
CH_4	2.3
CO_2	120,000
Arsenic	2E-04
Benzene	2.1E-03
Beryllium	1.2E-05
Cadmium	1.1E-03
Chromium III	1.344E-03
Chromium VI	5.6E-05
Formaldehyde	0.075
Hexane	1.8
Mercury	2.6E-04
Toluene	3.4E-03

3.2.7 Fugitive Sources (FUG)

Six (6) calculators are available in OCS AQS for fugitive sources based on the **process stream**. These calculators are designated as FUG-M01 (Gas), FUG-M02 (Liquid Natural Gas), FUG-M03 (Heavy Oil), FUG-M04 (Light Oil), FUG-M05 (Water/Oil), and FUG-M06 (Water/Oil/Gas).

All six calculators follow the same basic formulation, except that the EFs for various components and the weight fractions for CH_4 or VOC differ by stream type, as described below. Rather than repeating the same formulation, the equations are presented once here, and the different EFs and weight fractions are shown for different process streams.

For **each process stream**, fugitive total hydrocarbons (THC) emissions are calculated as follows:

$$E_{THC} = \left(\sum_{\text{comp}} (EF \times N)_{\text{comp}} \right) \times D \qquad (Eq. 17)$$

where:

E_{THC} = THC emissions for the stream type (lb/month)
EF = Emission factor of the component for the stream type (lb/component-day)
N = Total number of components (to specify by type)
D **= Number of days in month (day)**

Table 18 shows the EFs for THC, by component type, for each process stream.

Table 18: EFs for total hydrocarbons by component for each process stream (in lb/component-day)

Component	Gas (FUG-M01)	Liquid Natural Gas (FUG-M02)	Heavy Oil (<20 API Gravity) (FUG-M03)	Light Oil (≥20 API Gravity) (FUG-M04)	Water and Oil (FUG-M05)	Water, Oil, and Gas (FUG-M06)
Connector	0.011	0.011	4E-04	0.011	5.8E-03	0.011
Flange	0.021	5.8E-03	2.1E-05	5.8E-03	1.5E-04	0.021
Line	0.11	0.074	0.074	0.074	0.013	0.11
Other†	0.47	0.4	1.7E-03	0.4	0.74	0.74
Pump Seals	0.13	0.69	0.69	0.69	1.3E-03	0.13
Valve	0.24	0.13	4.4E-04	0.13	5.2E-03	0.24

† Other Includes compressor seals, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, and vents.

Fugitive CH_4 and VOC emissions for **each process stream** are calculated as follows:

$$E = E_{THC} \times WF \qquad (Eq. 18)$$

where:

E = Emissions for VOC or CH_4 (lb/month)
E_{THC} = THC emissions (lb/month), as described above
WF = Weight fraction of CH_4 or VOC for each stream type

Table 19 shows the weight fractions of CH_4 and VOC for each process stream.

Table 19: Weight fractions of CH_4 and VOC for each process stream

Weight Fraction	Gas (FUG-M01)	Liquid Natural Gas (FUG-M02)	Light Oil (≥ 20 API Gravity) (FUG-M03)	Heavy Oil (<20 API Gravity) (FUG-M04)	Water and Oil (FUG-M05)	Water, Oil, and Gas (FUG-M06)
CH_4	0.8816	0.612	0.612	0.942	0.612	0.612
VOC	0.0396	0.296	0.296	0.030	0.296	0.296

3.2.8 Loading Operations (LOA-M01R)

OCS AQS provides a calculator for loading operations, and it is designated as LOA-M01R.

THC emissions from loading operations are calculated as follows:

$$E_{THC} = \left(0.46 + 1.84 \times (0.44 \times P - 0.42) \times \frac{m}{(T_B + 460)} \times 1.02\right) \times Q \times \frac{42 \text{ gal}}{\text{barrel}} \times 10^{-3} \quad (Eq. 19)$$

where:

E_{THC} = THC emissions (lb/month)
P = True vapor pressure of the loaded liquid (psia) – see below
m **= Average molecular weight of vapors (lb/lb-mol)**

T_B = **Liquid bulk temperature in Fahrenheit (°F)** – OCS AQS converts this to Rankine
Q = **Total barrels transferred (bbl/month)**

The true vapor pressure of the loaded liquid, P, is calculated as follows:

$$P = e^{[A-(B/T_{LA})]} \quad (Eq. 20)$$

In the above equation, A and B represent empirical constants based on the Reid vapor pressure P_R, and T_{LA} is the daily average liquid surface temperature in Rankine, obtained by the following formulation:

$$A = 12.82 - 0.9672 \times \ln(P_R) \quad (Eq. 21)$$

$$B = 7{,}261 - 1{,}216 \times \ln(P_R) \quad (Eq. 22)$$

$$T_{LA} = 0.44 \times (T_{AA} + 460) + [0.56 \times (T_B + 460)] + \left(0.0079 \times a \times 1{,}437 \frac{\text{Btu}}{\text{ft}^2 \cdot \text{day}}\right) \quad (Eq. 23)$$

where:

P_R = **Reid vapor pressure (psia)**
T_{AA} = **Daily average ambient temperature in Fahrenheit (°F)** – OCS AQS converts this to Rankine
a = Tank paint solar absorptance, determined in OCS AQS based on user input for the storage tank **paint color** and the **paint condition** – see below

2017 Emission Inventory Study (Wilson et al. 2019) provides the values for Tables 17–20.

Table 20 shows the solar absorptance values used in OCS AQS based on the user-specified paint color and paint condition.

Table 20: Tank paint solar absorptance by paint color and condition

Paint Color	Paint Condition = Good	Paint Condition = Poor
Aluminum or Specular	0.39	0.49
Aluminum or Diffuse	0.60	0.68
Gray or Light	0.54	0.63
Gray or Medium	0.68	0.74
Red or Primer	0.89	0.91
White	0.17	0.34

VOC emissions are calculated as a percent of THC emissions as follows:

$$E_{VOC} = \frac{WP_{VOC}}{100} \times E_{THC} \quad (Eq. 24)$$

where:

WP_{VOC} = **VOC tank vapor weight percent (%)**

Operators were allowed to provide **reduction efficiencies** for emissions from loading operations by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.9 Losses from Flashing (LOS-M01R)

OCS AQS provides a calculator for losses from flashing, and it is designated as LOS-M01R.

VOC, CO_2, and CH_4 emissions due to flashing losses are calculated as follows:

$$E_f = (GOR_U - GOR_V) \times Q \times W_g \qquad (Eq. 25)$$

where:

E_f = Emissions from flashing (lb/month)
GOR_U = Gas-to-oil ratio for upstream vessel (scf/bbl)
GOR_V = Gas-to-oil ratio for vessel (scf/bbl)
Q = Throughput volume (bbl/month)
W_g = Gas density (lb/scf) – see below for the values used in OCS AQS

Table 21 shows the gas density values used for VOC, CO_2, and CH_4.

Table 21: Gas density values for losses from flashing

Pollutant	Gas density (lb/scf)
VOC	1.8E-03
CO_2	9.28E-04
CH_4	0.04

The gas-to-oil ratio (*GOR*) in the equation above is calculated using the Vasquez-Beggs correlation, as follows:

$$GOR = A \times (P_V + P_A)^B \times G_{fg} \times e^{\frac{C \times G_{oil}}{T_V + 460}} \qquad (Eq. 26)$$

where:

GOR = Gas-to-oil ratio (scf/bbl)
P_V = Vessel operating pressure (upstream/downstream) (psia)
P_A = Atmospheric pressure (psia)
A, *B*, and *C* are empirical constants – see below for the values used in OCS AQS
G_{fg} = Specific gravity of flash gas – see below for the values used in OCS AQS
T_V = Vessel operating temperature (upstream/downstream) (°F)
G_{oil} = API gravity

OCS AQS uses the following values in Table 22 and Table 23 for *A*, *B*, *C*, and based on API gravity provided by the operator:

Table 22: Parameters in Vasquez-Beggs correlation for API gravity > 30

Parameter	Value
A	0.0178
B	1.187
C	23.931
G_{fg}	0.93

Table 23: Parameters in Vasquez-Beggs correlation for API gravity ≤ 30

Parameter	Value
A	0.0362
B	1.0937
C	25.724
G_{fg}	1.08

Operators were allowed to provide reduction efficiencies for emissions from flashing by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.10 Mud Degassing (MUD)

OCS AQS provides a calculator for mud degassing, and it is designated as MUD-M01.

Emissions from mud degassing are calculated as follows:

$$E = \frac{WP}{100} \times EF \times D_{drill} \qquad (Eq. 27)$$

where:

E = Emissions (lb/ month)
WP = Mud degassing speciation fraction given as percent by weight (%)
EF = Emission factor (lb/day), which depends on the **type of mud** indicated by the operator
D_{drill} **= Days per month of drilling with mud (day/month)**

Table 24 below shows the speciation fraction default values used in OCS AQS.

Table 24: Mud degassing speciation fractions

Component	Percent Composition by Weight (%)
Methane (CH_4)	64.705
Ethane (C_2)	7.834
Propane (C_3)	12.977
Butane (C_4)	8.973
Pentane (C_5)	4.873
Carbon Dioxide (CO_2)	0.6

Table 25 below shows the EFs for mud degassing based on the type of mud.

Table 25: EFs for mud degassing

Type of Mud	EF (lb THC/day)
Water-based Mud	881.84
Oil-based Mud	198.41
Synthetic Mud	198.41

3.2.11 Natural Gas Engines (NGE)

Four calculators are available in OCS AQS for NGE, based on the engine type. These calculators are designated as NGE-M01R (2-Stroke, Lean Burn), NGE-M02R (4-Stroke, Lean Burn), NGE-M03R (4-Stroke, Rich Burn), and NGE-M04R (Clean Burn).

For all NGE, emissions are calculated as follows:

$$E = EF \times H \times U \times 0.001 \qquad (Eq. 28)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
H **= Fuel heating value (Btu/scf)**
U **= Total Fuel usage (Mscf/month)**

EFs for NGE vary by engine type, as shown in the four tables below, one for each engine type. Table 26 shows EFs for 2-Stroke, Lean Burn engines; Table 27 for 4-Stroke, Lean Burn engines; Table 28 for 4-Stroke, Rich Burn; and Table 29 for Clean Burn engines.

Table 26: EFs for natural gas engines: 2-stroke, lean burn (NGE-M01R)

Pollutants	EF (lb/MMBtu)
VOC	0.12
SO_2	5.88E-04
NO_x	1.94
PM_{10}	0.0384
$PM_{2.5}$	0.0384
CO	0.353
CH_4	1.45
CO_2	110
Acetaldehyde	7.76E-03
Benzene	1.94E-03
Ethylbenzene	1.08E-04
Formaldehyde	0.0552
Hexane	4.45E-04
PAH	1.34E-04
Toluene	9.63E-04
2,2,4-Trimethylpentane	8.46E-04
Xylenes	2.68E-04

Table 27: EFs for natural gas engines: 4-stroke, lean burn (NGE-M02R)

Pollutants	EF (lb/MMBtu)
VOC	0.118
SO_2	5.88E-04
NOx	0.847
PM_{10}	7.71E-5
$PM_{2.5}$	7.71E-5
CO	0.557
CH_4	1.25
CO_2	110
Acetaldehyde	8.36E-03
Benzene	4.40E-04
Ethylbenzene	3.97E-05
Formaldehyde	0.0528
Hexane	1.11E-03
PAH	2.69E-05
Toluene	4.08E-04
2,2,4-Trimethylpentane	2.50E-04
Xylenes	1.84E-04

Table 28: EFs for natural gas engines: 4-stroke, rich burn (NGE-M03R)

Pollutants	EF (lb/MMBtu)
VOC	0.03
SO_2	5.88E-04
NO_x	2.27
PM_{10}	9.50E-3
$PM_{2.5}$	9.50E-3
CO	3.51
CH_4	0.23
CO_2	110
Acetaldehyde	2.79E-03
Benzene	1.58E-03
Ethylbenzene	2.48E-05
Formaldehyde	0.0205
PAH	1.41E-04
Toluene	5.58E-04
Xylenes	1.95E-04

Table 29: EFs for natural gas engines: clean burn (NGE-M04R)

Pollutants	EF (lb/MMBtu)
VOC	0.12
SO_2	5.88E-04
NO_x	0.59
PM_{10}	7.71E-5
$PM_{2.5}$	7.71E-5
CO	0.88
CH_4	1.25
CO_2	110
Acetaldehyde	3.52E-03
Benzene	6.00E-04
Ethylbenzene	4.19E-05
Formaldehyde	0.0495
Hexane	6.48E-04
Toluene	5.05E-04
2,2,4-Trimethylpentane	1.05E-04
Xylenes	1.71E-04

3.2.12 Dual-Fuel Turbines (NGT)

OCS AQS provides three calculators for NGT. These calculators are designated as NGT-M01R (Natural Gas, Known Sulfur Content), NGT-M02R (Natural Gas, Unknown Sulfur Content), and NGT-M03R (Diesel).

3.2.12.1 Natural Gas Dual-Fuel Turbines with *Known* Fuel Gas Sulfur Content (NGT-M01R)

Emissions from natural gas dual-fuel turbines with known fuel sulfur content are calculated as follows:

$$E = EF \times H \times U \times 0.001 \qquad (Eq. 29)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
H **= Fuel heating value (Btu/scf)**
U **= Total Fuel usage (Mscf/month)**
S **= Fuel sulfur content (wt %)** – This factor is not shown in the formula above but is a required field in OCS AQS and is used to obtain the EF for SO_2.

Table 30 shows the EFs for natural gas dual-fuel turbine engines when the sulfur content is known.

Table 30: EFs for natural gas dual-fuel turbines with known fuel gas sulfur content

Pollutants	EF (lb/MMBtu)
VOC†	2.10E-03
SO_2†	0.94 × *S*
NO_x†	0.32
PM_{10}†	1.9E-03
$PM_{2.5}$†	1.9E-03
CO†	0.082
N_2O†	3E-03
CH_4	8.6E-03
CO_2	110
Acetaldehyde	4E-05
Benzene	1.2E-05
Cadmium	6.93E-06
Chromium III	1.28E-05[a]
Chromium VI	5.32E-07
Ethylbenzene	3.2E-05
Formaldehyde	7.1E-04
Mercury	6.63E-06
PAH	2.2E-06
Toluene	1.3E-04
Xylenes	6.4E-05

Notes: † Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

[a] USEPA 2016

3.2.12.2 Natural Gas Dual-Fuel Turbines with *Unknown* Fuel Gas Sulfur Content (NGT-M02R)

When the fuel sulfur content is not known, emissions from natural gas dual-fuel turbines are calculated using the same formulation as above, but the SO_2 EF has no dependency on the sulfur content. Emissions are calculated as follows:

$$E = EF \times H \times U \times 0.001 \qquad (Eq. 30)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
H **= Fuel heating value (Btu/scf)**
U **= Total Fuel usage (Mscf/month)**

EFs are identical to when the sulfur content is known, except for the SO_2 EF. For completeness, Table 31 shows the EFs for natural gas dual-fuel turbines with unknown sulfur content.

Table 31: EFs for natural gas dual-fuel turbines with unknown fuel gas sulfur content

Pollutants	EF (lb/MMBtu)
VOC†	2.10E-03
SO_2†	3.47E-03
NO_x†	0.32
PM_{10}†	1.9E-03
$PM_{2.5}$†	1.9E-03
CO†	0.082
N_2O†	3E-03
CH_4	8.6E-03
CO_2	110
Acetaldehyde	4E-05
Benzene	1.2E-05
Cadmium	6.93E-06
Chromium III	1.28E-05
Chromium VI	5.32E-07
Ethylbenzene	3.2E-05
Formaldehyde	7.1E-04
Mercury	6.63E-06
PAH	2.2E-06
Toluene	1.3E-04
Xylenes	6.4E-05

† Operators were allowed to provide reduction efficiencies for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.12.3 Dual-Fuel Turbines using Diesel Fuel (NGT-M03R)

Emissions from diesel dual-fuel turbines are calculated as follows:

$$E = EF \times 10^{-6} \times U \times 7.1 \frac{\text{lb}}{\text{gal}} \times 19{,}300 \frac{\text{Btu}}{\text{lb}} \qquad (Eq. 31)$$

where:

E = Emissions (lb/month)
EF = Emission factor (lb/MMBtu)
U = **Total fuel usage (gal/month)**
S = **Fuel sulfur content (wt %)** – This factor is not shown in the formula above but is a required field in OCS AQS and is used to obtain certain EFs.

Table 32 shows the EFs for diesel dual-fuel turbine engines.

Table 32: EFs for dual-fuel turbines using diesel fuel

Pollutants	EF (lb/MMBtu)
VOC†	4.1E-04
Pb	1.4E-05
SO_2†	1.01 × S
NO_x†	0.88
PM_{10}†	4.3E-03
$PM_{2.5}$†	4.3E-03
CO†	3.3E-03
CO_2	157
Arsenic	1.1E-05
Benzene	5.5E-05
Beryllium	3.1E-07
Cadmium	4.8E-06
Chromium III	9.02E-06
Chromium VI	1.98E-06
Formaldehyde	2.8E-04
Mercury	1.2E-06
PAH	4E-05

† Operators were allowed to provide **reduction efficiencies** for these pollutants by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.13 Pneumatic Pumps (PNE-M01R)

OCS AQS provides a calculator for pneumatic pumps, and it is designated as PNE-M01R.

CO_2, CH_4, and VOC emissions for pneumatic pumps are calculated as follows:

$$E = t \times r_{fu} \times MW \times \frac{MP}{100} \times \frac{1\ \text{lb·mol}}{379.4\ \text{scf}} \qquad (Eq. 32)$$

where:

E = Emissions (lb/month)
t = Hours of operation per month (hr/month)
r_{fu} = Fuel usage rate (scf/hour)
MW = Mole weight of gas (lb/lb·mol)
MP = Mole percentage of gas (%) – This factor is automatically calculated in OCS AQS from the sales gas data.

Table 33 shows the mole weight of the pollutants used in OCS AQS for pneumatic pump emissions.

Table 33: Mole weight of the pollutants for pneumatic pumps

Pollutants	Mole Weight (lb/lb·mol)
CH_4	16.043
CO_2	44.01
VOC	Automatically calculated from sales gas

Hazardous air pollutant (HAP) emissions are calculated based on the VOC emissions obtained from the equation above and applying the speciation profile data:

$$E_{HAP} = E_{VOC} \times \left(\frac{WP_{HAP}}{WP_{VOC}}\right) \qquad (Eq. 33)$$

where:

E_{VOC} = VOC emissions (lb/month)
WP_{HAP} = HAP average weight (%)
WP_{VOC} = VOC average weight (%)

Table 34 shows the HAP speciation profile with average weight in %.

Table 34: Speciation profile used to calculate HAP emissions based on VOC emissions

Pollutants	Average weight (%)
Benzene	0.01855
Ethylbenzene	1.15E-03
Hexane	0.35195
Toluene	2.80E-03
2,2,4-Trimethylpentane	7.0E-04
Xylenes	4.80E-03
VOC	17.21

Operators were allowed to provide reduction efficiencies for emissions from loading operations by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.14 Pneumatic Controllers (PRE- M01R)

OCS AQS provides a calculator for pneumatic pumps, and it is designated as PRE-M01R.

CO_2, CH_4, and VOC emissions for pneumatic controllers are calculated as follows:

$$E = N \times t \times r_{fu} \times MW \times \frac{MP}{100} \times \frac{1 \text{ lb·mol}}{379.4 \text{ scf}} \qquad (Eq. 34)$$

where:

E = Emissions (lb/month)
N **= Number of units**
t **= Hours of operation per month (hr/month)**
r_{fu} **= Fuel usage rate (scf/hour)**
MW = Mole weight of gas (lb/lb·mol)
MP = Mole percentage of gas (%) – This factor is automatically calculated in OCS AQS from the sales gas data.

Table 35 shows the mole weight of the pollutants used in OCS AQS for pneumatic pump emissions.

Table 35: Mole weight of the pollutants for pneumatic pumps

Pollutants	Mole Weight (lb/lb·mol)
CH_4	16.043
CO_2	44.01
VOC	Automatically calculated from sales gas

HAP emissions are calculated based on the VOC emissions obtained from the equation above and applying the speciation profile data:

$$E_{HAP} = E_{VOC} \times \left(\frac{WP_{HAP}}{WP_{VOC}}\right) \qquad (Eq. 35)$$

where:

E_{VOC} = VOC emissions (lb/month)
WP_{HAP} = HAP average weight (%)
WP_{VOC} = VOC average weight (%)

Table 36 shows the HAP speciation profile with average weight in %.

Table 36: Speciation profile used to calculate HAP emissions based on VOC emissions

Pollutants	Average weight (%)
Benzene	0.01855
Ethylbenzene	1.15E-03
Hexane	0.35195
Toluene	2.80E-03
2,2,4-Trimethylpentane	7.0E-04
Xylenes	4.80E-03
VOC	17.21

Operators were allowed to provide reduction efficiencies for emissions from loading operations by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.15 Storage Tanks (STO)

Four calculators are available in OCS AQS for storage tanks, based on the type. These calculators are designated as STO-M01R (Horizontal, Rectangular), STO-M02R (Vertical, Rectangular), STO-M03R (Horizontal, Cylindrical), and STO-M04R (Vertical, Cylindrical). Standing and working losses from storage tanks are calculated in OCS AQS.

All four calculators follow the same basic formulation, as shown below. A definable difference among the different calculation methods lies in how the space volume is obtained, which depends on the geometry of the storage tank.

Total Hydrocarbon (THC) emissions from storage tanks are calculated as follows:

$$E_{THC} = E_{LS} + E_{LW} \qquad (Eq. 36)$$

where:

E_{THC} = Total THC emissions (lb/month)
E_{LS} = THC emissions from standing losses (lb/month)
E_{LW} = THC emissions from working losses (lb/month)

THC emissions from standing losses are calculated as follows:

$$E_{LS} = D \times V_V \times W_V \times K_E \times K_S \qquad (Eq. 37)$$

where:

E_{LS}= THC emissions from standing losses (lb/month)
D **= Number of days in month (day/month)**
V_V = Vapor space volume (ft^3)
W_V = Vapor density (lb/ft^3)
K_E = Vapor space expansion factor
K_S = Vented vapor saturation factor

The vapor space volume V_V is based on the geometry of the storage tanks, as follows:

For horizontal, rectangular tanks (STO-M01R):

$$V_V = L \times W \times H_{VO} \qquad (Eq. 38)$$

where:

L **= Tank shell length (ft)**
W **= Tank shell width (ft)**
H_{VO}= Vapor space outage (ft)

In the above expression, the vapor space outage H_{VO} is given by the following:

$$H_{VO} = (H - H_L) \qquad (Eq. 39)$$

where:

H **= Tank shell height (ft)**
H_L**= Tank average liquid height (ft)**

For vertical, rectangular tanks (STO-M02R), V_V is obtained by the following:

$$V_V = W_1 \times W_2 \times H_{VO} \qquad (Eq. 40)$$

where:

W_1 **= Horizontal width of rectangular tank (ft)**
W_2 **= Second horizontal width of rectangular tank (ft)**

The vapor space outage H_{VO} is given by the same expression as in the case of the horizontal, rectangular tanks:

$$H_{VO} = (H - H_L) \qquad (Eq. 41)$$

H = **Tank shell height (ft)**
H_L= **Tank average liquid height (ft)**

For horizontal, cylindrical tanks (STO-M03R), V_V is obtained by the following:

$$V_V = L \times d \times H_{VO} \qquad (Eq. 42)$$

where:

L = **Tank shell length (ft)**
d = **Tank shell diameter (ft)**

The vapor space outage H_{VO} in this case is calculated as follows:

$$H_{VO} = 0.5 \times \frac{\pi}{4} \times d \qquad (Eq. 43)$$

Finally, for vertical, cylindrical tanks (STO-M04R), V_V is obtained by the following:

$$V_V = \frac{\pi}{4} \times d^2 \times H_{VO} \qquad (Eq. 44)$$

where:

d = **Tank shell diameter (ft)**

The vapor space outage H_{VO} for vertical, cylindrical tanks is calculated as follows:

$$H_{VO} = H - H_L + H_{RO} \qquad (Eq. 45)$$

where:

H = **Tank shell height (ft)**
H_L= **Tank average liquid height (ft)**
H_{RO}= Roof outage (ft)

The expression for the roof outage H_{RO} depends on the **roof type** which is provided by the operator during the input process and can be one of the following: **Cone or Peaked / Dome / Flat**.

For the Cone or Peaked roof type:

$$H_{RO} = \frac{1}{3} \times H_R \qquad (Eq. 46)$$

where:

H_R = **Tank roof height (ft)**

For the Dome roof type:

$$H_{RO} = H_R \times \left[\frac{1}{2} + \frac{1}{6} \times \left(\frac{H_R}{d/2}\right)^2\right] \qquad (Eq. 47)$$

where $\boldsymbol{H_R}$ and $\boldsymbol{d}$ are as previously defined.

For the Flat roof type:

$$H_{RO} = 0$$

Returning to the expression for emissions from standing losses, the vapor density W_V is calculated as follows:

$$W_V = \frac{M_V \times P_{VA}}{10.731 \frac{\text{psia·ft}^3}{\text{lb-mole·°R}} \times T_V} \qquad (Eq. 48)$$

where:

> M_V **= Vapor molecular weight (lb/lb-mol)**
> P_{VA} = True vapor pressure (psia)
> T_V = Average vapor temperature (°R)

The true vapor pressure P_{VA} is calculated as follows:

$$P_{VA} = e^{\left(A - \frac{B}{T_{LA}}\right)} \qquad (Eq. 49)$$

In the above equation, *A* and *B* represent empirical constants based on the Reid vapor pressure P_R, as follows:

$$A = 12.82 - 0.9672 \times \ln(P_R) \qquad (Eq. 50)$$

$$B = 7{,}261 - 1{,}216 \times \ln(P_R) \qquad (Eq. 51)$$

where:

> P_R **= Reid vapor pressure (psia)**

T_{LA} is the daily average liquid surface temperature in Rankine, obtained by the following:

$$T_{LA} = 0.4 \times T_{AA} + [0.6 \times (T_B + 460)] + \left(0.005 \times a \times 1{,}437 \frac{\text{Btu}}{\text{ft}^2\text{·day}}\right) \qquad (Eq. 52)$$

where:

> T_{AA} = Daily average ambient temperature (°R) – see below
> T_B **= Liquid bulk temperature in Fahrenheit (°F)** – OCS AQS converts this to Rankine
> a = Tank paint solar absorptance, determined in OCS AQS based on user input for the **storage tank paint color** and the **paint condition**.

Table 37 shows the solar absorptance values used in OCS AQS based on the user-specified paint color and paint condition.

Table 37: Tank paint solar absorptance by paint color and condition

Paint Color	Paint Condition = Good	Paint Condition = Average	Paint Condition = Poor
Aluminum or Specular	0.39	0.44	0.49
Aluminum or Diffuse	0.60	0.64	0.68
Gray or Light	0.54	0.58	0.63
Gray or Medium	0.68	0.71	0.74
Red or Primer	0.89	0.90	0.91
White	0.17	0.25	0.34

The daily average ambient temperature T_{AA} in the above expression is obtained as follows:

$$T_{AA} = 0.5 \times (T_{AMAX} + T_{AMIN}) + 460 \quad (Eq. 53)$$

where:

T_{AMAX} = **Average daily maximum ambient temperature in Fahrenheit (°F)**
T_{AMIN} = **Average daily minimum ambient temperature in Fahrenheit (°F)**

Note that OCS AQS converts the temperature to Rankine in obtaining T_{AA}.

The vapor space expansion factor K_E is calculated as follows:

$$K_E = 0.0018 \times \left[0.7 \times \left((T_{AMAX} + 460) - (T_{AMIN} + 460)\right) + 0.02 \times a \times 1{,}437 \frac{\text{Btu}}{\text{ft}^2\text{·day}}\right] \quad (Eq. 54)$$

Finally, the last variable in the equation for standing losses is the vented vapor saturation factor K_S and this is calculated as follows:

$$K_S = \frac{1}{1 + 0.053 \times P_{VA} \times H_{VO}} \quad (Eq. 55)$$

where the true vapor pressure P_{VA} and vapor space outage H_{VO} terms are as defined previously, above. This completes the formulation for standing losses.

Working losses E_{LW} are calculated as follows:

$$E_{LW} = 5.614 \frac{\text{ft}^3}{\text{bbl}} \times Q \times W_V \times K_N \times K_P \times K_B \quad (Eq. 56)$$

where:

Q = **Monthly net throughput (bbl/month)**
W_V = Vapor density (lb/ft^3), as obtained above

K_N , K_P , and K_B represent, respectively, the working loss turnover, working loss product, and vent setting correction factors which are provided in OCS AQS. K_P and K_B are set to constant values equal to 0.75 and 1, respectively. K_N is calculated as follows:

$$K_N = \begin{cases} 1, N \leq 36 \\ \dfrac{180 + N}{6N}, N > 36 \end{cases}$$

where:

N = Number of turnovers

The number of turnovers N is in turn given by the following:

$$N = 5.614 \frac{\text{ft}^3}{\text{bbl}} \times Q \times V_{LX} \qquad (Eq. 57)$$

where:

V_{LX} = Tank volume (ft^3)

As was the case with the vapor volume V_V , the tank volume V_{LX} depends on the tank geometry, as follows:

For horizontal, rectangular tanks (STO-M01R),

$$V_{LX} = L \times W \times H \qquad (Eq. 58)$$

For vertical, rectangular tanks (STO-M02R),

$$V_{LX} = W_1 \times W_2 \times (H - 2) \qquad (Eq. 59)$$

For horizontal, cylindrical tanks (STO-M03R),

$$V_{LX} = \frac{\pi}{4} \times d^2 \times L \qquad (Eq. 60)$$

Finally, for vertical, cylindrical tanks (STO-M04R),

$$V_{LX} = \frac{\pi}{4} \times d^2 \times L \qquad (Eq. 61)$$

Emissions of VOC, CH_4, and ethane were calculated as follows, respectively, based on the specification profiles:

$$E_{VOC} = 0.467 \times E_{TCH} \qquad (Eq. 62)$$

$$E_{CH_4} = 0.463 \times E_{TCH} \qquad (Eq. 63)$$

$$E_{ETH} = 0.07 \times E_{TCH} \qquad (Eq. 64)$$

Operators were allowed to provide **reduction efficiencies** for emissions from loading operations by entering the required information (e.g., control equipment type, reduction efficiency in %) in OCS AQS.

3.2.16 Cold Vents (VEN)

OCS AQS provides a calculator for cold vents, and it is designated as VEN-M01R.

VOC emissions from cold vents are calculated as follows:

$$E_{VOC} = C_{VOC} \times 10^{-6} \times \frac{m_{VOC} \times V \times 1{,}000}{379.4 \frac{\text{scf}}{\text{lb·mol}}} \qquad (Eq. 65)$$

where:

E_{VOC} = VOC emissions (lb/month)
C_{VOC} **= Concentration of VOC in the vented gas (ppmv)**
m_{VOC} = Molecular weight of VOC (lb/lb·mol)
V **= Volume of vented gas (Mscf)**

CH_4 and CO_2 emissions are calculated using the same formulation as follows. The equations are provided individually below for clarity:

$$E_{CH_4} = WP_{CH_4} \times \frac{m_S}{379.4 \frac{\text{scf}}{\text{lb. mol}}} \times 1000 \times V \qquad (Eq. 66)$$

$$E_{CO_2} = WP_{CO_2} \times \frac{m_S}{379.4 \frac{\text{scf}}{\text{lb. mol}}} \times 1000 \times V \qquad (Eq. 67)$$

where:

E = CH_4 or CO_2 emissions (lb/month)
m_S = Sales gas mole weight (lb/lb·mol)
WP = Weight percent of CH_4 or CO_2 (%)

Finally, HAP emissions are calculated based on the VOC emissions obtained from the equation above and applying the speciation profile data:

$$E_{HAP} = E_{VOC} \times \left(\frac{WP_{HAP}}{WP_{VOC}}\right) \qquad (Eq. 68)$$

where:

E_{VOC} = VOC emissions (lb/month)
WP_{HAP} = HAP average weight (%)
WP_{VOC} = VOC average weight

4 QA/QC of 2021 Emissions Inventory (Platform Sources)

4.1 Overview

OCS AQS provides an automated baseline QA/QC to ensure that the required input activity data is entered by operators and that input values fall within pre-defined ranges determined by BOEM to be reasonable. However, the automated checks do not identify macro trends that can point to outliers or tag potential discrepancies and other issues associated with the emissions data (e.g., incorrect sulfur content conversions between wt% and PPMv, or potentially high H_2S concentrations in combustion flares because of gas sent off from an AMI regenerator). Further, a thorough review was necessary to ensure that all active facilities in the GOM in 2021 submitted their required emissions data. This section describes the initial automated QA/QC built into OCS AQS and explains additional QA/QC and other investigations performed to ensure that all required facilities reported their emissions.

4.2 Baseline QA/QC in OCS AQS

As already noted, OCS AQS performs automated QA/QC of certain input parameters to ensure that required input data are entered by the operators and the input values are reasonable. The QA/QC checks in OCS AQS include error and range checking, missing required data inputs, and data format correctness. The methods used were initially based on the same data quality checks that were used in the legacy GOADS inventory system. Additional checks and changes to range checking were implemented based on observations made during the initial review of the 2021 draft emissions data. Table 38 provides the automated QA/QC parameter checks and range of allowable values, where applicable. The automated QA/QC range checks are set globally for each equipment type under the data request, and these checks will flag out-of-range data for entered activity data. See Table 50 for equipment type abbreviations.

Table 38: Initial automated system QA/QC ranges from the legacy GOADS system

#	Emission Unit	Emission Unit Description	Parameter	Value Range
1	AMI001	Amine gas sweetening unit	Hours of Operation per Month [hr]	[0–744]
2	BOI001	Boiler/heater/burner (Diesel)	Total Fuel Usage [lb/month]	[1–160,000]
3	BOI001	Boiler/heater/burner (Diesel)	Fuel Sulfur Content [wt%]	[0–5]
4	BOI002	Boiler/heater/burner (Waste Oil)	Total Fuel Usage [lb/month]	[0–28,800]
5	BOI002	Boiler/heater/burner (Waste Oil)	Fuel Sulfur Content [wt%]	[0–5]
6	BOI003	Boiler/heater/burner (Gas)	Total Fuel Usage [Mscf/month]	[0–74,088]
7	DIE001	Diesel or gasoline engine (Gasoline)	Total Fuel Usage [gallons/month]	[0–1,812]
8	DIE001	Diesel or gasoline engine (Gasoline)	Fuel Heating Value [Btu/lb]	[14,475–24,125]
9	DIE002	Diesel or gasoline engine (Max HP < 600)	Total Fuel Usage [gallons/month]	[0–350,000]
10	DIE002	Diesel or gasoline engine (Max HP < 600)	Fuel Heating Value [Btu/lb]	[18,000–21,000]
11	DIE003	Diesel or gasoline engine (Max HP >= 600)	Total Fuel Usage [gallons/month]	[0–350,000]
12	DIE003	Diesel or gasoline engine (Max HP >= 600)	Fuel Heating Value [Btu/lb]	[12,996–22,500]
13	DIE003	Diesel or gasoline engine (Max HP >= 600)	Fuel Sulfur Content [wt%]	[0–5]
14	DRI001	Drilling equipment (Gasoline)	Total Fuel Usage [gallons/month]	NA
15	DRI002	Drilling equipment (Diesel)	Total Fuel Usage [gallons/month]	[0–163,380]

#	Emission Unit	Emission Unit Description	Parameter	Value Range
16	DRI002	Drilling equipment (Diesel)	Fuel Sulfur Content [wt%]	[0–5]
17	DRI003	Drilling equipment (Natural Gas)	Total Fuel Usage [Mscf/month]	NA
18	FLA001	Combustion flare	Total Volume of Gas Flared (Not Including Pilot) [Mscf]	[0–700,000]
19	FLA001	Combustion flare	Concentration of H2S in the Flare Gas [ppm]	[0–50,000]
20	FLA001	Combustion flare	Flare Gas Heating Value [Btu/scf]	[100–3,200]
21	FLA001	Combustion flare	Combustion Efficiency of the Flare [%]	[1–100]
22	FLA-Pilot	Combustion flare - Pilot	Pilot Feed Rate [Mscf/day]	[0–700,000]
23	FLA-Pilot	Combustion flare - Pilot	Number of Days in Month [Day]	[0–31]
24	Fugitives	Fugitive Sources	Number of Operating Days in Month [days]	[0–31]
25	GLY001	Glycol dehydrator unit	Hours of Operation per Month [hr]	[0–744]
26	LOA001	Loading operations	VOC Tank Vapor Weight Percent [wt%]	[0–99]
27	LOA001	Loading operations	Average Molecular Weight of Vapors [lb/lb-mol]	[0–210]
28	LOA001	Loading operations	Daily Average Ambient Temperature [deg F]	[32–120]
29	LOA001	Loading operations	Liquid Bulk Temperature [deg F]	[32–200]
30	LOS001	Losses from flashing	Atmospheric Pressure [psia]	[12–16]
31	LOS001	Losses from flashing	Upstream Operating Pressure [psig]	[0–5,235.3]
32	LOS001	Losses from flashing	Upstream Operating Temperature [deg F]	[70–295]
33	LOS001	Losses from flashing	API Gravity	[16–68]
34	MUD001	Mud degassing	Days per Month of Drilling with Mud [Days]	[0–31]
35	NGE	Natural gas engine	Total Fuel Usage [Mscf/month]	[0–23,000]
36	NGE	Natural gas engine	Fuel Heating Value [Btu/scf]	[500–1,900]
37	PNE001	Pneumatic pumps	Hours of Operation per Month [hr]	[0–744]
38	PRE001	Pneumatic controllers	Hours of Operation per Month [hr]	[0–744]
39	VEN001	Cold vent	Concentration of VOC in the Vented Gas [ppmv]	[0–1,000,000]
40	STO-HR001	Storage Tank - Horizontal, Rectangular Tank	Number of Days in Month [days/month]	[0–31]
41	STO-HR001	Storage Tank - Horizontal, Rectangular Tank	Reid Vapor Pressure [psia]	[0.5–20]
42	STO-HR001	Storage Tank - Horizontal, Rectangular Tank	Average Daily Maximum Ambient Temperature [deg F]	[32–130]
43	STO-HR001	Storage Tank - Horizontal, Rectangular Tank	Average Daily Minimum Ambient Temperature [deg F]	[0–100]
44	STO-HR001	Storage Tank - Horizontal, Rectangular Tank	Liquid Bulk Temperature [deg F]	[0–200]
45	STO-HR001	Storage Tank - Horizontal, Rectangular Tank	Vapors Molecular Weight [lb/lb-mole]	[16–200]
46	STO-VR001	Storage Tank - Vertical - Rectangular Tank	Number of Days in Month [days/month]	[0–31]
47	STO-VR001	Storage Tank - Vertical - Rectangular Tank	Reid Vapor Pressure [psia]	[0.5–20]
48	STO-VR001	Storage Tank - Vertical - Rectangular Tank	Average Daily Maximum Ambient Temperature [deg F]	[32–130]

#	Emission Unit	Emission Unit Description	Parameter	Value Range
49	STO-VR001	Storage Tank - Vertical - Rectangular Tank	Average Daily Minimum Ambient Temperature [deg F]	[32–100]
50	STO-VR001	Storage Tank - Vertical - Rectangular Tank	Liquid Bulk Temperature [deg F]	[32–200]
51	STO-VR001	Storage Tank - Vertical - Rectangular Tank	Vapors Molecular Weight [lb/lb-mole]	[16–200]
52	STO-HC001	Storage Tank - Horizontal - Cylindrical Tank	Number of Days in Month [days/month]	[0–31]
53	STO-HC001	Storage Tank - Horizontal - Cylindrical Tank	Reid Vapor Pressure [psia]	[0.5–20]
54	STO-HC001	Storage Tank - Horizontal - Cylindrical Tank	Average Daily Maximum Ambient Temperature [deg F]	[32–130]
55	STO-HC001	Storage Tank - Horizontal - Cylindrical Tank	Average Daily Minimum Ambient Temperature [deg F]	[32–100]
56	STO-HC001	Storage Tank - Horizontal - Cylindrical Tank	Liquid Bulk Temperature [deg F]	[32–200]
57	STO-HC001	Storage Tank - Horizontal - Cylindrical Tank	Vapors Molecular Weight [lb/lb-mole]	[16–200]
58	STO-VC001	Storage Tank - Vertical - Cylindrical Tank	Number of Days in Month [days/month]	[0–31]
59	STO-VC001	Storage Tank - Vertical - Cylindrical Tank	Reid Vapor Pressure [psia]	[0.5–20]
60	STO-VC001	Storage Tank - Vertical - Cylindrical Tank	Average Daily Maximum Ambient Temperature [deg F]	[32–130]
61	STO-VC001	Storage Tank - Vertical - Cylindrical Tank	Average Daily Minimum Ambient Temperature [deg F]	[32–100]
62	STO-VC001	Storage Tank - Vertical - Cylindrical Tank	Liquid Bulk Temperature [deg F]	[32–200]
63	STO-VC001	Storage Tank - Vertical - Cylindrical Tank	Vapors Molecular Weight [lb/lb-mole]	[16–200]
64	NGT	Turbines - Natural Gas	Total Fuel Usage [Mscf/month]	[0–140,000]
65	NGT	Turbines - Natural Gas	Fuel Sulfur Content [wt%]	[0–5]
66	NGT	Turbines - Natural Gas	Fuel Heating Value [Btu/scf]	[711–1,875]
67	NGT-D	Turbines - Diesel	Total Fuel Usage [gallons/month]	[0–140,600]
68	NGT-D	Turbines - Diesel	Fuel Sulfur Content [wt%]	[0–5]

4.3 Forensic-Level QA/QC of Emissions Data

For the detailed QA/QC of the 2021 emissions inventory after the initial submission by the operators, the draft emissions data was examined using a variety of statistical methods to identify patterns, trends, outliers, and any other observed data anomalies. The draft emissions data represents all platform emissions data calculated in OCS AQS by the April 22, 2022, submittal deadline.

QA/QC was conducted using best practices and subject matter expertise pertaining to oil and gas emissions calculation methods for source types found in the GOM. The following methods were used to identify outliers:

- Quantitative data sorting – Activity data are sorted from high to low to flag outliers including substantially high or extremely low values as described in Section 4.6.2.
- Datasets comparison – 2021 inventory data is compared to the historical 2017 data to identify and describe similarities and differences as described in Section 5.

  - ***NOTE:*** Dataset comparison between inventory years have some limitations including differences in operating conditions, decommissioned platforms, new platforms, and discrepancies in emission unit IDs that limit some one-to-one comparisons.
- Measures of central tendency and data dispersion – The measure of central tendency describes a large dataset by summarizing the dataset with a "single" most representative value. There are three standard measures of central tendency: arithmetic mean, median, and mode. For example, initial QA/QC of the draft inventory identified a flare gas throughput anomaly by analyzing the measures of central tendency (e.g., arithmetic mean) for the throughput datasets in 2017 and 2021, for all the facilities with flaring activities. In addition, data dispersion analysis was used to detect activity data anomalies. Data dispersion, also known as standard deviation, is the measure of the spread of data about the mean.
  - ***NOTE:*** Measures of central tendency and data dispersion analysis method were incorporated in OCS AQS for the development of the anomaly detector tool in the Analytics module of OCS AQS.
- Visual data inspection methodologies including:
  - Column plots for annual emissions by equipment type, Official Protraction Diagram (OPD) areas, and structure types
  - Stacked column plots for GHG emissions by equipment type, OPD areas, and structure types
  - Histogram plots for continuous univariate data such as count of records by throughput values range for a specific equipment type to determine the number of anomalies
  - Histograms and column plots for discrete and qualitative data such as equipment count, count of facilities by operational status (e.g., operating, permanently shutdown), and count of records by sulfur weight percentage values
  - Pie charts for equipment contributions to a specific pollutant annual emission
  - Time series plots for monthly emissions and activity data such as throughput
  - Interquartile range technique, which measures the spread and dispersion of data
  - Box Plot (Box and Whiskers), which use a graphical method to display the spread and variation of data through their quartile

  NOTE: Plots and charts for annual and monthly emissions were generated using the OCS AQS interface and exported to the QA/QC report. Other plots related to activity data were generated manually in Excel and incorporated into the report.

After data anomalies were identified using the methods described above, operators were contacted via email with a request to review the specific issue. In the email, the Team provided a description of the issue, a list of affected platforms and equipment, and details describing what parameters were involved in the calculation of emissions. For those issues that required operators to correct or add additional information, their OCS AQS inventories were set to "corrective action," which enabled edit-rights access to the data, so the appropriate actions could be taken by the operator. This step was necessary, as the 2021 emissions inventory was locked after each operator submitted their original draft data by the April 22, 2022, reporting deadline. After changes were made in OCS AQS and emissions recalculated, operators resubmitted the inventories to BOEM to review and finalize.

4.4 Review of Inventory Completeness

Another important QA/QC task was to determine completeness of the inventory by examining if there were facilities operating in the GOM that did not report emissions in OCS AQS for the 2021 inventory. Two separate investigations were necessary to accomplish this task: (1) compare the facilities in 2021 OCS AQS inventory against the BSEE Technical Information Management System (TIMS) database to identify and resolve any discrepancies; and (2) identify facilities in 2021 OCS AQS inventory which did not report emissions and resolve any issues. The first investigation revealed whether there were facilities missing in the OCS AQS database, and the second investigation determined if any of the facilities in OCS AQS failed to report and why.

4.4.1 Comparison Between TIMS and OCS AQS Platforms

To accomplish this task, a comparison was performed between the facilities (or platforms) in the 2021 OCS AQS inventory and the platforms managed in the TIMS database. TIMS is a critical information system operated and maintained by the BSEE Office of Administration. The system automates many of the business and regulatory functions supporting BOEM and BSEE. TIMS serves as the database of record for permitted facilities operating in the GOM and Alaska and includes key information about the operational status of these facilities. The data used in this analysis was acquired from https://www.data.boem.gov/Platform/PlatformStructures/Default.aspx.

The Team conducted a comparative analysis to investigate platforms in TIMS that were potentially missing from the 2021 inventory. Prior to this analysis, the following steps were taken to pre-process TIMS data:

1. Platforms that were removed prior to 2021 were filtered out from the TIMS data.
2. The operating platforms under State Lease authority were filtered out (i.e., omitted from the analysis) to keep only the operating platforms under the OCS Lease authority. The OCS Lease authority includes OCS State, Right-of-Use and Easement, Right-of-Way, and "Blank" Authority Types.
3. The operating platforms with a blank install date were also filtered out. This action eliminates the platforms that have not been constructed.

As presented in Table 39, the analysis determined that 81 platforms listed in TIMS were not in the 2021 OCS AQS inventory. These 81 missing platforms belong to 32 operating companies. The data presented under the "Decommissioning Status" column were extracted from https://bobson.maps.arcgis.com/apps/dashboards/400bba386d3d4ec58396dbaa559c422c.

Based on further review of the decommissioning status and TIMS Authority Type/Status, it was determined that 58 platforms either were decommissioned or had their lease terminated (TERMIN), relinquished (RELINQ or RELQ), or expired (EXP). These statuses indicate that no emissions occurred during the 2021 reporting period. An additional 14 facilities were listed as Right-of-Way (ROW) / Active (ACT). The following four facilities (shown below by Facility ID#: Company Name) had a status of production (PROD) and were contacted via email to determine if emissions from these facilities needed to be reported; however, no responses were received.

1. 22445-1: Chevron
2. 2253-2: Contango
3. 2522-1: Bois d' Arc Exploration LLC
4. 27008-1: Resources, Inc.

Finally, four of the remaining five missing facilities had a status of SOP, indicating that these platforms were under a "Suspension of Production (SOP)," and, therefore, no reportable emissions were expected. Lastly, one facility, Facility ID# 2219-1 under Apache Shelf Exploration LLC, had a Right-of-Use and Easement authority type with a blank authority status; therefore, the reason for its absence could not be clearly established.

Based on this analysis, no additional platforms were added to OCS AQS or expected to have failed to report emissions.

Table 39: List of platforms in TIMS that are not in the 2021 draft emission inventory

#	Company Name	Company ID	Facility ID	(Authority Type / Authority Status)	Decommissioned	Removal Date
1	ANKOR Energy LLC	3059	22039-1	OCS Lease / TERMIN	no	8/23/2021
2	ANKOR Energy LLC	3059	22039-4	OCS Lease / TERMIN	no	8/23/2021
3	ANKOR Energy LLC	3059	22039-3	OCS Lease / TERMIN	no	8/23/2021
4	ANKOR Energy LLC	3059	22039-2	OCS Lease / TERMIN	no	8/23/2021
5	ANKOR Energy LLC	3059	22039-5	OCS Lease / TERMIN	no	8/23/2021
6	ANKOR Energy LLC	3059	23461-1	OCS Lease / TERMIN	no	7/13/2021
7	Arena Offshore, LP	2628	2193-1	OCS Lease / TERMIN	no	8/10/2021
8	Castex Offshore, Inc.	2970	10268-1	Right-of-Way / RELQ	no	9/19/2021
9	Castex Offshore, Inc.	2970	2512-1	OCS Lease / RELINQ	no	10/13/2021
10	Chevron U.S.A. Inc.	78	22445-1	OCS Lease / PROD	yes	-
11	Cochon Properties, LLC	3288	20922-3	Right-of-Way / ACT	yes	-
12	Contango Operators, Inc.	2503	2253-2	OCS Lease / PROD	no	-
13	Kinetica Partners, LLC	3203	20739-1	Right-of-Way / ACT	yes	-
14	McMoRan Oil & Gas LLC	2312	10084-1	OCS Lease / TERMIN	yes	-
15	McMoRan Oil & Gas LLC	2312	10077-1	OCS Lease / TERMIN	yes	-
16	McMoRan Oil & Gas LLC	2312	22411-1	OCS Lease / TERMIN	yes	-
17	McMoRan Oil & Gas LLC	2312	21716-1	OCS Lease / TERMIN	yes	-
18	McMoRan Oil & Gas LLC	2312	23925-1	OCS Lease / TERMIN	no	7/2/2022
19	McMoRan Oil & Gas LLC	2312	10089-1	OCS Lease / TERMIN	no	11/29/2021
20	Manta Ray Gathering Company, L.L.C.	1796	23212-1	Right-of-Way / ACT	no	-
21	Anglo-Suisse Offshore Partners, LLC	2738	1866-1	OCS Lease / RELINQ	no	-
22	Apache Corporation	105	24260-1	OCS Lease / TERMIN	no	-
23	Bennu Oil & Gas, LLC	3308	2027-1	OCS Lease / TERMIN	no	-
24	Bennu Oil & Gas, LLC	3308	1942-1	OCS Lease / TERMIN	yes	-
25	Bennu Oil & Gas, LLC	3308	1319-1	OCS Lease / TERMIN	no	10/25/2021
26	Blue Dolphin Pipe Line Company	125	919-1	Right-of-Way / RELQ	yes	-
27	Bois d' Arc Exploration LLC	3093	2522-1	OCS Lease / PROD	no	-
28	Century Exploration New Orleans, LLC	2714	22103-1	Right-of-Use and Easement / TERMIN	yes	-
29	Conn Energy, Inc.	1071	21337-3	Right-of-Way / ACT	no	-
30	Conn Energy, Inc.	1071	21337-1	OCS Lease / TERMIN	no	7/25/2021
31	Conn Energy, Inc.	1071	21337-2	OCS Lease / TERMIN	no	7/25/2021
32	EC Offshore Properties, Inc.	3147	20217-1	OCS Lease / SOP	no	-
33	EC Offshore Properties, Inc.	3147	20217-2	OCS Lease / SOP	no	-
34	EC Offshore Properties, Inc.	3147	1525-1	OCS Lease / SOP	yes	-

#	Company Name	Company ID	Facility ID	(Authority Type / Authority Status)	Decommissioned	Removal Date
35	EC Offshore Properties, Inc.	3147	1526-1	OCS Lease / SOP	no	-
36	Freeport-McMoRan Energy LLC	2313	23874-2	OCS Lease / TERMIN	yes	-
37	Freeport-McMoRan Energy LLC	2313	23872-1	OCS Lease / TERMIN	yes	-
38	Freeport-McMoRan Energy LLC	2313	23874-1	OCS Lease / TERMIN	yes	-
39	Freeport-McMoRan Energy LLC	2313	23876-1	OCS Lease / TERMIN	yes	-
40	Freeport-McMoRan Energy LLC	2313	23896-1	OCS Lease / TERMIN	yes	-
41	Freeport-McMoRan Energy LLC	2313	23874-4	OCS Lease / TERMIN	yes	-
42	Freeport-McMoRan Energy LLC	2313	23873-1	OCS Lease / TERMIN	yes	-
43	Freeport-McMoRan Energy LLC	2313	24248-9	OCS Lease / TERMIN	yes	-
44	Freeport-McMoRan Energy LLC	2313	24248-8	OCS Lease / TERMIN	yes	-
45	Freeport-McMoRan Energy LLC	2313	24248-7	OCS Lease / TERMIN	yes	-
46	Freeport-McMoRan Energy LLC	2313	24248-2	OCS Lease / TERMIN	yes	-
47	Grand Isle Corridor, LP	3387	22311-1	Right-of-Way / ACT	yes	-
48	Gulf South Pipeline Company, LP	178	516-1	Right-of-Way / ACT	no	-
49	Gulf South Pipeline Company, LP	178	2039-1	Right-of-Way / ACT	no	-
50	High Island Offshore System, L.L.C.	410	25002-2	Right-of-Way / ACT	no	-
51	High Island Offshore System, L.L.C.	410	25002-3	Right-of-Way / ACT	no	-
52	High Island Offshore System, L.L.C.	410	25002-4	Right-of-Way / ACT	no	-
53	High Island Offshore System, L.L.C.	410	25002-5	Right-of-Way / ACT	no	-
54	High Island Offshore System, L.L.C.	410	25024-3	Right-of-Way / ACT	no	-
55	High Island Offshore System, L.L.C.	410	25024-2	Right-of-Way / ACT	no	-
56	Hoactzin Partners, L.P.	2801	10468-1	Right-of-Use and Easement / TERMIN	no	7/21/2021
57	Hoactzin Partners, L.P.	2801	10503-1	Right-of-Use and Easement / TERMIN	no	7/21/2021
58	Hoactzin Partners, L.P.	2801	1360-1	OCS Lease / TERMIN	no	9/12/2021
59	Hoactzin Partners, L.P.	2801	1601-1	Right-of-Use and Easement / TERMIN	no	8/23/2021
60	Manta Ray Offshore Gathering Company, L.L.C.	2162	23021-1	Right-of-Way / ACT	no	-
61	Maritech Resources, Inc.	2409	27008-1	OCS Lease / PROD	no	-
62	Matagorda Island Gas Operations, LLC	2747	2127-1	OCS Lease / TERMIN	no	-
63	Matagorda Island Gas Operations, LLC	2747	1985-1	OCS Lease / TERMIN	no	-

#	Company Name	Company ID	Facility ID	(Authority Type / Authority Status)	Decommissioned	Removal Date
64	Matagorda Island Gas Operations, LLC	2747	1976-1	OCS Lease / TERMIN	no	-
65	Matagorda Island Gas Operations, LLC	2747	2161-1	OCS Lease / TERMIN	no	-
66	Matagorda Island Gas Operations, LLC	2747	1950-1	OCS Lease / TERMIN	no	-
67	Matagorda Island Gas Operations, LLC	2747	10170-1	OCS Lease / TERMIN	yes	-
68	Matagorda Island Gas Operations, LLC	2747	10228-1	OCS Lease / TERMIN	yes	-
69	Matagorda Island Gas Operations, LLC	2747	1958-1	OCS Lease / TERMIN	no	-
70	Matagorda Island Gas Operations, LLC	2747	2178-1	OCS Lease / TERMIN	no	-
71	Apache Shelf Exploration LLC		2219-1	Right-of-Use and Easement/ TERMIN	no	-
72	PROBE RESOURCES US LTD.	2989	21967-2	Right-of-Use and Easement / TERMIN	yes	-
73	Sojitz Energy Venture, Inc.	2655	2046-1	OCS Lease / TERMIN	no	6/6/2022
74	Sojitz Energy Venture, Inc.	2655	23646-1	OCS Lease / TERMIN	no	6/5/2022
75	Sojitz Energy Venture, Inc.	2655	1717-1	OCS Lease / TERMIN	no	6/20/2022
76	Taylor Energy Company LLC	2863	23051-1	OCS Lease / RELINQ	no	-
77	Tengasco, Inc.	3008	1511-1	OCS Lease / TERMIN	no	4/30/2021
78	Tennessee Gas Pipeline Company, L.L.C.	14	524-1	Right-of-Way / EXP	no	-
79	Tennessee Gas Pipeline Company, L.L.C.	14	524-3	Right-of-Way / EXP	no	-
80	Texas Eastern Transmission, LP	176	25001-1	Right-of-Way / RELQ	no	11/15/2021
81	Texas Eastern Transmission, LP	176	25026-1	Right-of-Way / RELQ	no	11/21/2021

4.4.2 2021 Platforms by Submission Status

In the previous section, the 81 facilities missing from OCS AQS were reported and analyzed to identify the underlying reason for their absence from the 2021 inventory. This section, on the other hand, focuses on the facilities that are already in OCS AQS 2021 inventory but failed to submit their emissions inventory.

Facilities were identified in OCS AQS when the operators for the facilities did not contact the Team to request an account, thereby resulting in failure to report their 2021 emissions or provide justification explaining why they were not required to submit.

There are 1,738 platforms (including operating and non-operating) listed in the 2021 OCS AQS draft inventory, and these platforms were owned by 64 companies. Of these, 1,723 platforms have successfully submitted their calculated 2021 emissions. The remaining 15 facilities, operated by five companies, failed to submit their inventories before the submittal deadline. Table 40 lists those 15 facilities and the associated companies.

As an additional QA/QC step on the completeness of the 2021 inventory, the Team reviewed the Authority Type and Authority Status in TIMS (see column TIMS [Authority Type / Authority Status] in

Table 40) for those facilities. Only 1 of the 15 facilities that did not submit had a status of PROD in TIMS, specifically Facility ID# 1259-1 under Castex Offshore, Inc.

Multiple attempts were made by the Team to contact these companies; however, no attempts were successful.

Table 40: Facilities in OCS AQS that did not submit their 2021 emissions data

#	Company Name	Company ID	Facility ID	TIMS [Authority Type / Authority Status]
1	Garden Banks Pipeline, LLC	02202	33032-1	Right-of-Way / ACT
2	Rooster Petroleum, LLC	02871	794-1	OCS Lease / TERMIN
3	Rooster Petroleum, LLC	02871	10213-2	OCS Lease / TERMIN
4	Rooster Petroleum, LLC	02871	2445-1	OCS Lease / TERMIN
5	Gulf Offshore LLC	03628	2423-1	Right-of-Use and Easement / Approved
6	Cochon Properties, LLC	03288	20922-1	OCS Lease / TERMIN
7	Castex Offshore, Inc.	02970	2557-1	OCS Lease / TERMIN
8	Castex Offshore, Inc.	02970	27053-1	OCS Lease / TERMIN
9	Castex Offshore, Inc.	02970	580-1	OCS Lease / TERMIN
10	Castex Offshore, Inc.	02970	2419-1	OCS Lease / TERMIN
11	Castex Offshore, Inc.	02970	2419-2	OCS Lease / TERMIN
12	Castex Offshore, Inc.	02970	2644-1	OCS Lease / UNIT
13	Castex Offshore, Inc.	02970	2564-1	OCS Lease / TERMIN
14	Castex Offshore, Inc.	02970	1207-1	OCS Lease / UNIT
15	Castex Offshore, Inc.	02970	1259-1	OCS Lease / PROD

4.4.3 Summary of Possible Reasons for Non-reporters

Based on the results of the above two sections (Sections 4.4.1 and 4.4.2), 96 platforms did not report their 2021 emissions inventory to OCS AQS. Of the 96 platforms, 15 of them had access to OCS AQS but did not calculate or submit their 2021 emissions. The remaining 81 were completely missing from OCS AQS 2021 inventory.

Table 41 below summarizes the count of non-reporters and their corresponding suspected reason for delinquency or absence from the 2021 submitted inventory. Figure 6 provides a visual representation of Table 41. It can be assumed that OCS Lease / TERMIN, OCS Lease / RELINQ, and OCS Lease / SOP platforms (representing 51 of 96 non-reporting platforms) had no emissions to submit to the 2021 inventory in OCS AQS. However, the remaining 45 platforms might have emissions to report. If the assumptions are true, the 2021 draft inventory would be 99.97%[3] complete.

[3] Inventory completion $=100-\frac{Count\ of\ Platforms\ Might\ Possibly\ Have\ Emissions\ to\ Report}{Total\ Count\ of\ Platforms\ in\ OCS\ AQS\ 2021\ Inventory+Total\ count\ of\ Non\text{-}Reporters\ Platforms}=100-\frac{45}{1738+96}=99.97\%$

Table 41: Summary of possible reasons for non-reporters

Reason of Absence	Count of Platforms
Submittal Available but Did Not Submit (Table 34)	15
OCS Lease / TERMIN	44
OCS Lease / RELINQ	3
OCS Lease / SOP	4
Right-of-Use and Easement / TERMIN	5
Right-of-Way (ROW)	20 (14 ROW/ ACT + 4 ROW / RELQ + 2 ROW / EXP)
Undetermined	5 (4 OCS Lease / PROD + 1 Right-of-Use and Easement without Authority Status)
Total Count	**96**

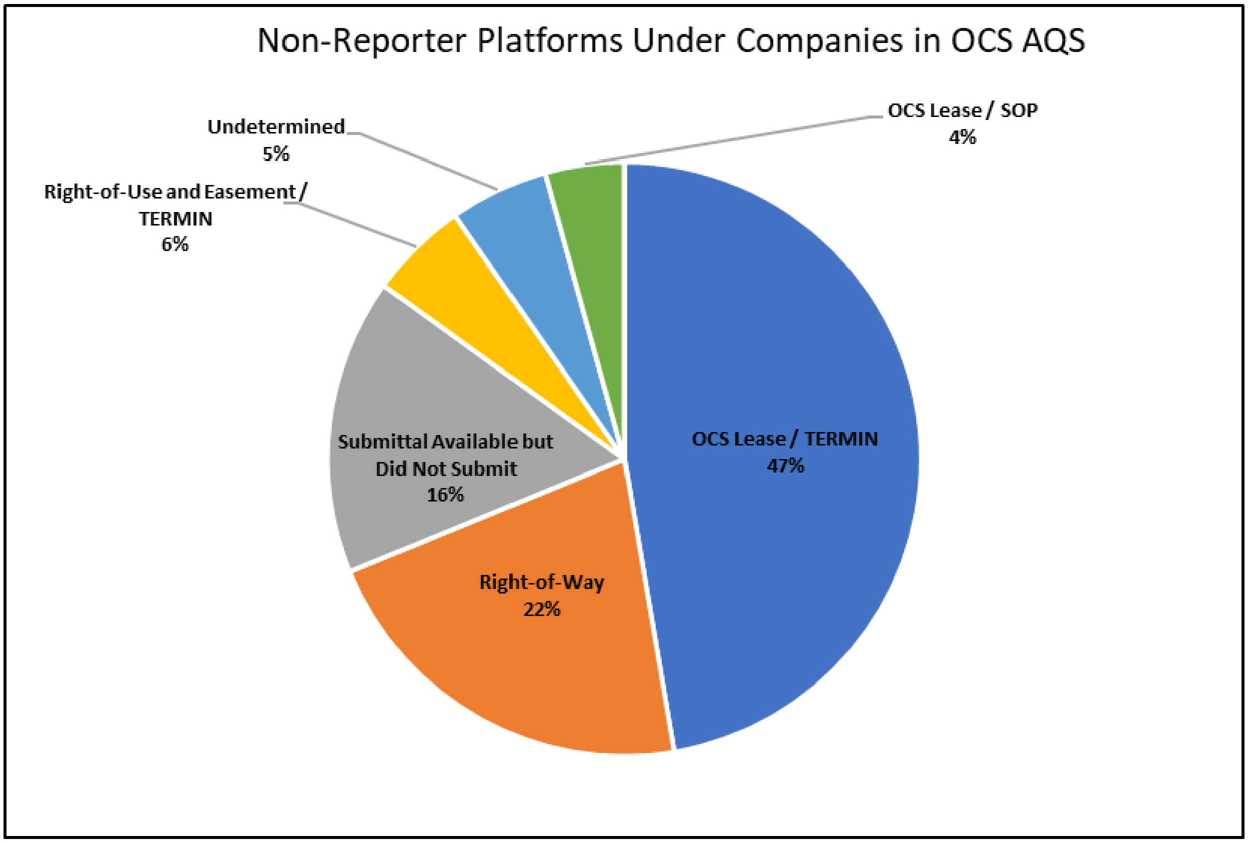


Figure 6: Summary of possible reasons for non-reporters, with percentages

4.5 Review of Facilities Operational Status

Operators that submitted their facility activity data and calculated their emissions under the OCS AQS 2021 inventory can have various standard operating statuses, including Operating (OP), Temporarily Shut Down (TS), Permanently Shut Down (PS) and Operating Not Reporting Emissions (ONRE). Figure 7 compares the operational status of platforms in 2021 and 2017. The total number of operating platforms decreased by 212 in the 2021 reporting year in comparison to 2017.

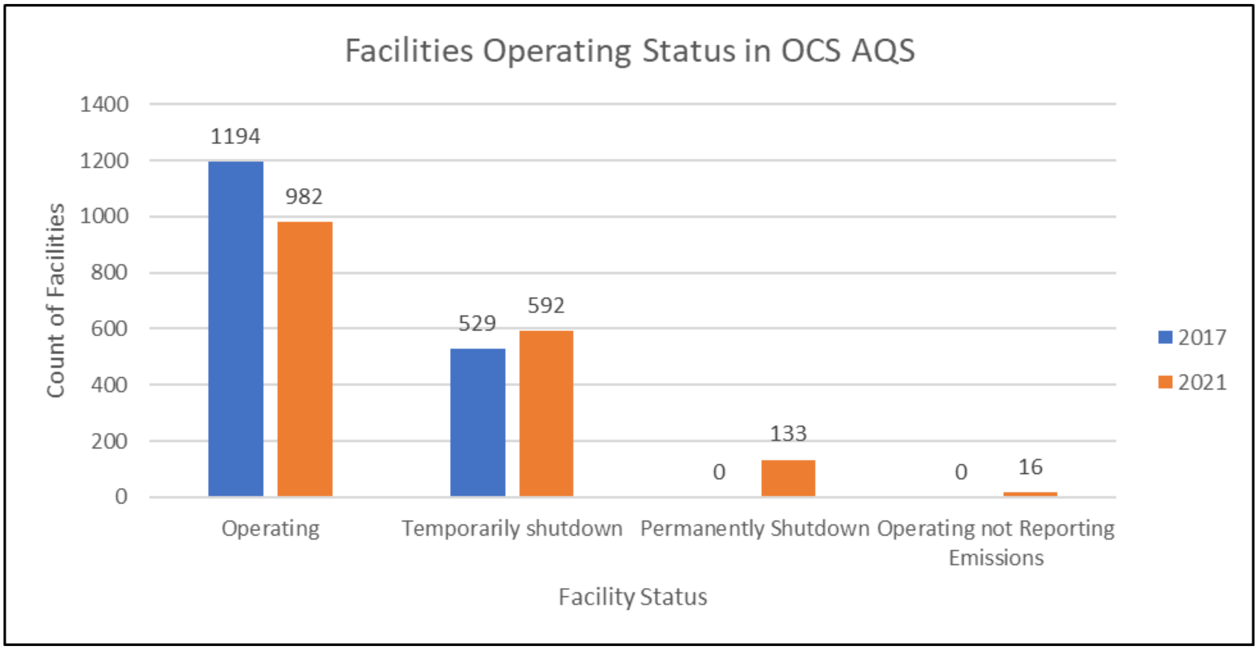


Figure 7: Differences between years 2017 (blue, left columns) and 2021 (orange, right columns) of facilities count (number) by operational status

According to the 2021 inventory data, 410 of the operators that submitted their platform inventory did not have any equipment (emission units). Table 42 below summarizes the count of platforms with no equipment by their operational status. This table shows that 38 platforms out of the 410 were marked as OP, while the remaining were either TS, PS, or ONRE. Table 43 lists the number of operating platforms with no equipment by the company name (this table is only for the 38 operating platforms).

Table 42: Count of platforms (number) with no equipment by operational status

Operational Status	Count of Platforms with No Equipment
OP (Submitted only)	38
PS	52
TS	304
ONRE	16
Total Count	**410**

Table 43: Count of operational platforms (number) with no equipment by company name and ID

Company Name	Company ID	Count of Platforms with No Equipment
Arena Offshore, LP	02628	7
Castex Offshore, Inc.	02970	6
Cochon Properties, LLC	03288	1
Fieldwood Energy Offshore LLC	03035	2
Fieldwood Energy, LLC	03295	9
Garden Banks Pipeline, LLC	02202	1
GOM Shelf LLC	02451	1
Gulf Offshore LLC	03628	1
Renaissance Offshore, LLC	03209	2
Rooster Petroleum, LLC	02871	3
Sanare Energy Partners, LLC	03520	3
Shell Pipeline Company LP	02289	1
Transcontinental Gas Pipe Line Company, LLC	00011	1
Total Count	**-**	**38**

4.6 Additional QA/QC Checks

When the operators enter data in OCS AQS in the Activity and Emissions Manager, most fields have automated QA/QC checks (Table 38), such as making sure that numerical values instead of words are entered and values fall within a specific range (e.g., no negative values for throughput). The following sections provide an overview of the additional tools and safeguards implemented in OCS AQS, as well as the actions taken by the Team, to verify that the activity data is as accurate as possible. These system tools and actions are intended to ensure that the activity data, which is provided by the operators and used to calculate the monthly emissions, is reliable.

As a result of the analysis and checks done in this section, the Team has improved the acceptable ranges for different activity data variables, such as flare gas heating values, number of operating hours and days within a month, and natural gas and diesel fuels heating values. Furthermore, a new anomaly detector tool was integrated into OCS AQS to help users perform the checks and analyses before submitting their data. This tool prevents submission of erroneous data in future reporting cycles.

4.6.1 Sales Gas Compositions

During the 2021 reporting cycle in OCS AQS, operators could specify the sales gas compositions when filling in facility data (optional). The QA field automatically checks the percentage total, ensuring the summation of weights percentages is between 99 and 101%. OCS AQS pre-defined calculators for pneumatic pumps, pneumatic controllers, cold vents, and combustion flares depend on the sales gas compositions for some of the pollutants' emissions calculations. If the operators did not provide sales gas compositions, the emissions for the processes that use the calculators listed above were not calculated. Operators will be required to enter sales gas composition for future emissions inventory efforts, as OCS AQS has been updated to makes the field mandatory.

After analyzing the sales gas data that was exported using the QA – Sales Gas report (OCS AQS Reports module), it was observed that 51 facilities did not provide sales gas compositions. However, 26 out of those 51 facilities either did not have any emission units or were set to facility-wide zero emissions. The remaining 25 facilities had emission units that did not depend on the sales gas compositions for emissions calculations. This means that the missing sales gas data did not impact any of the emissions calculations, and no further corrective actions from the operators are required. A list of these facilities missing the sales gas compositions is presented below in Table 44.

Table 44: Facilities that did not provide sales gas data in the 2021 draft data

#	Company Name	Company ID	Facility ID
1	Arena Offshore, LP	02628	20618-5
2	Arena Offshore, LP	02628	20849-1
3	Arena Offshore, LP	02628	21448-3
4	Arena Offshore, LP	02628	2208-1
5	Arena Offshore, LP	02628	22296-1
6	Arena Offshore, LP	02628	2346-1
7	Arena Offshore, LP	02628	26111-1
8	BP Exploration & Production Inc.	02481	2665-1
9	Cantium, LLC	03481	20049-2
10	Cantium, LLC	03481	20060-1
11	Cantium, LLC	03481	2030-1
12	Cantium, LLC	03481	20332-2
13	Cantium, LLC	03481	20388-1
14	Cantium, LLC	03481	20454-2
15	Cantium, LLC	03481	20456-1
16	Cantium, LLC	03481	20470-1
17	Cantium, LLC	03481	22752-1
18	Cantium, LLC	03481	23086-1
19	Castex Offshore, Inc.	02970	1207-1
20	Castex Offshore, Inc.	02970	1259-1
21	Castex Offshore, Inc.	02970	2564-1
22	Chevron Pipe Line Company	00400	21781-2
23	Chevron Pipe Line Company	00400	784-1
24	Dauphin Island Gathering Partners	01847	24146-1
25	Dauphin Island Gathering Partners	01847	24258-1
26	Dauphin Island Gathering Partners	01847	258-1
27	Fieldwood Energy Offshore LLC	03035	22451-1
28	Fieldwood Energy Offshore LLC	03035	22696-1
29	Fieldwood Energy, LLC	03295	10070-1
30	Fieldwood Energy, LLC	03295	20724-4
31	Fieldwood Energy, LLC	03295	20745-3
32	Fieldwood Energy, LLC	03295	21988-3
33	Fieldwood Energy, LLC	03295	21988-6
34	Fieldwood Energy, LLC	03295	21988-7
35	Fieldwood Energy, LLC	03295	21988-8
36	Fieldwood Energy, LLC	03295	228-2
37	Fieldwood Energy, LLC	03295	23967-1
38	Fieldwood Energy, LLC	03295	86-1
39	GOM Shelf LLC	02451	20046-2

#	Company Name	Company ID	Facility ID
40	GOM Shelf LLC	02451	20046-3
41	GOM Shelf LLC	02451	20046-4
42	Renaissance Offshore, LLC	03209	21244-2
43	Renaissance Offshore, LLC	03209	22277-1
44	Sea Robin Pipeline Company, LLC	00207	25015-1
45	Sea Robin Pipeline Company, LLC	00207	25016-1
46	Sea Robin Pipeline Company, LLC	00207	25017-1
47	Shell Pipeline Company LP	02289	1093-2
48	Shell Pipeline Company LP	02289	1093-1
49	Talos Third Coast LLC	03619	23930-1
50	Transcontinental Gas Pipe Line Company, LLC	00011	20928-1
51	Transcontinental Gas Pipe Line Company, LLC	00011	2648-1

NOTE: It is important to mention that in future reporting cycles, OCS AQS will mandate that operators have to enter sales gas compositions for all facilities to avoid any calculation issues.

4.6.2 Data Range Checks

4.6.2.1 API Gravity

API gravity is used in the formulas for calculating emissions from losses from flashing (under calculator LOS-M01R). The Team analyzed all API provided values under 407 losses from flashing processes in the 2021 reporting cycle and found that the maximum provided value was 65 and the lowest was 25. A typical API gravity value for most petroleum liquids ranges between 9 and 70 degrees (Engineering Toolbox 2007). Therefore, all provided values in the 2021 inventory in OCS AQS are considered acceptable, and no corrective action was required.

The average value of the 3,216 API gravity monthly records (under the 407 process) in OCS AQS was 35.68. This value is comparatively close to the Gulf Coast API gravity weighted average of crude oil input to refineries reported for 2020 and 2021 by the U.S. Energy Information Administration, ranging between 33 and 34 (EIA 2023). This gave the Team higher confidence in the accuracy of the provided data.

NOTE: As a result of findings from the analysis conducted in this section, the upper and lower bounds of the API gravity range in OCS AQS were modified to allow lower and higher bounding values (modified from [16–68] to [9–70]).

4.6.2.2 Combustion Flare

4.6.2.2.1 Combustion Flare Efficiency

Combustion flare efficiency is a mandatory data request field that operators must provide for all active combustion flares because it is used in the formulas for calculating combustion flare emissions (under calculator FLA-M01). Multiple factors should be considered when determining the combustion flare efficiency, including adherence with the manufacturer's maintenance requirements.

The Team analyzed all combustion flare efficiency values provided for 114 flaring processes in the 2021 reporting cycle and found that the maximum provided value was 98% and the lowest was 95% with an average of 96.33%. Table 3-2 of the *Year 2017 Emissions Inventory Study* document indicated that the combustion flare efficiency should range from 90% to 99% (Wilson et al. 2019). In addition, AP-42 Ch 13.5 states that properly operated flares should achieve at least 98% combustion efficiency in the flare plume, meaning that hydrocarbon and CO emissions amount to less than 2% of hydrocarbons in the gas stream (USEPA 1995). However, the University of Michigan research suggests that onshore flares were found to be unlit approximately 3–5% of the time; even when lit, they were found operating at low efficiency. Combined, those factors lead to an average effective flaring efficiency rate of only 91% (Plant et al. 2022). Therefore, all provided values in the 2021 inventory in OCS AQS are considered acceptable, and no corrective action was required.

> ***NOTE:*** In the 2021 inventory, 22 records had a value of 0% combustion flare efficiency. Those record entries were under two facilities, Facility ID# 70020-1 belonging to Eni US Operating Co. Inc. and Facility ID# 23846-1 under Shell Pipeline Company LP. Facility ID# 70020-1 zeroed out the emissions from the combustion flare that had 0% efficiency and reported this combustion flare was removed in the reporting year. The other facility (Facility ID# 23846-1) reported that during the months the efficiency was reported as 0, the combustion flare was out of service. Both facilities used the "zero out emissions" feature in OCS AQS to report those two non-emitting flaring cases.

4.6.2.2.2 Combustion Flare Smoking Conditions

Combustion flare smoking condition (no, light, medium, and heavy) is a mandatory data request field for which the operators must provide a value for all active combustion flares because it is used in the formulas for calculating PM_{10} and $PM_{2.5}$ combustion flare emissions (under calculator FLA-M01).

The Team analyzed the smoking conditions provided for 114 flaring processes in the 2021 reporting cycle and found that 63% reported light smoke conditions. Table 45 below summarizes the findings of the smoking conditions analysis. As shown 72 flaring processes operated with light smoke, and only 1 process reported medium smoke conditions.

Table 45: Smoking conditions analysis results in the 2021 draft data

Smoking Condition	Count of Processes	Percentage
No Smoke	33	29%
Light Smoke	72	63%
Medium Smoke	1	1%
Heavy Smoke	0	0%
Blank (not provided)	8	7%

> ***NOTE:*** The eight (8) processes that did not report smoking conditions are under zeroed-out (not emitting) combustion flare emission units.

4.6.2.3 Fuel Heating Value

Fuel heating value is used in the formulas for calculating emissions from combustion equipment (including boilers, DRI diesel or gasoline engines, natural gas engines, and turbines) and combustion flares. The Team analyzed all heating values in the 2021 reporting cycle and compared them to the acceptable ranges provided in Table 3-2 of the *Year 2017 Emissions Inventory Study* document (Wilson et al. 2019) as well as the ranges published in the Engineering ToolBox website (Engineering Toolbox 2005). Table 46 summarizes the results of the analysis conducted.

Table 46: Heating values ranges analysis and results

Fuel	Range in 2017 Final	Engineering ToolBox	Range in 2021 Draft	Requires Corrective Actions?
Natural Gas / Flare gas [Btu/scf]	1,000–1,500	950–1,150	300–1,848.75	The minimum and maximum values in the 2021 inventory were out of acceptable range and required further investigations to identify the emission units that have those values and request verification and/or corrective actions.
Diesel [Btu/lb]	18,000–20,000	18,315–19,604	18,000–20,139	All diesel heating values in the 2021 inventory in OCS AQS are considered acceptable, and no further corrective action was required.

As shown above, 300 Btu/scf was the lowest natural gas heating value in the 2021 inventory. Upon further investigation, it was found that these low values were specified for the flare gas heating values under the combustion flare. Typical values for Flare Gas Heating Values are generally between 1,020 and 1,600 Btu/scf. Four processes were identified for low and high outliers after all the Flare Gas Heating Values submitted by operators. Table 47 provides further details on these four flare processes, which were all under the company name BP Exploration & Production Inc. The Team contacted BP Exploration & Production Inc. and requested corrective action for those values. The company confirmed the inaccuracy of those values and corrected them accordingly (Table 48 shows the revised values).

> ***NOTE:*** The low heating values under the combustion flares caused the unexpected decrease in flaring processes emissions (see section 6.6.4.1, in which the flare emissions were analyzed).

The maximum natural gas heating value of 1,848.75 Btu/scf provided in the 2021 inventory was also outside the acceptable range. These values were specified for a boiler fuel heating value over 4 months for one boiler process under the Cox Operating LLC. Table 49 provides further details about those processes. The Team contacted the Cox Operating LLC and requested corrective action for those values. The company confirmed the inaccuracy of those values and corrected them accordingly. The 1,848.75 Btu/scf value for September, October, November, and December was corrected to 1,050 Btu/scf.

Table 47: Out-of-range flare gas heating values (Btu/scf) per month in the 2021 draft data

Company Name	Facility ID	Emission Unit	Process	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BP Exploration & Production Inc.	1001-1	FL-01	FL-NPf	300	300	300	300	300	300	300	300	300	300	300	300
BP Exploration & Production Inc.	1101-1	FL-01	FL-NPf	300	300	300	300	300	300	300	300	300	300	300	300
BP Exploration & Production Inc.	1215-1	FL-01	FL-NPf	300	300	300	300	300	300	300	300	300	300	300	300
BP Exploration & Production Inc.	1223-1	FL-01	FL-NPf	300	300	300	300	300	300	300	300	300	300	300	300

Table 48: Revised flare gas heating values (Btu/scf) per month in the 2021 draft data

Company Name	Facility ID	Emission Unit	Process	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BP Exploration & Production Inc.	1001-1	FL-01	FL-NPf	1,136	1,129	1,136	1,145	1,150	1,154	1,196	1,194	1,196	1,199	1,193	1,193
BP Exploration & Production Inc.	1101-1	FL-01	FL-NPf	1,470	1,485	1,483	1,462	1,457	1,485	1,148	1,482	1,490	1,488	1,481	1,484
BP Exploration & Production Inc.	1215-1	FL-01	FL-NPf	1,270	1,272	1,265	1,258	1,267	1,274	1,249	1,264	1,268	1,272	1,275	1,273
BP Exploration & Production Inc.	1223-1	FL-01	FL-NPf	1,136	1,129	1,136	1,145	1,150	1,154	1,196	1,194	1,196	1,199	1,193	1,193

Table 49: Out-of-range boiler fuel heating values (Btu/scf) per month in the 2021 draft data

Company Name	Facility ID	Emission Unit	Process	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cox Operating LLC	1490-3	HTBRN-1	BOI<10n	1,081.8	1,081.8	1,081.8	1,081.8	1,081.8	1,081.8	1,081.8	1,081.8	1,848.75	1,848.75	1,848.75	1,848.75

NOTE: Some instances under flares and turbines had natural gas fuel heating values that were slightly out of range (between 1,500 and 1,516 Btu/scf). The Team decided to accept those values and not to consider them as out of range. Therefore, no corrective actions were taken.

4.6.2.4 Hours of Operation per Month

The maximum range for the number of hours of operation per month in OCS AQS was set to 744 (31 days x 24 hours) for all months in the 2021 reporting period. Although this is the highest possible number of hours for some months, a lower maximum number of hours should have been applied in OCS AQS for others, such as February (672 or 696 hours) and April, June, September, and November (720 hours). If operators used the Copy Monthly Data feature in OCS AQS to fill in the activity values, then it was possible that some users mistakenly copied the January data to the rest of the months and not correct the hours of operation for the months with fewer maximum allowable hours.

A thorough analysis was conducted on all equipment types with the hours of operation fields to identify the emission units that have the wrong number of hours under the months that do not have 31 days. Table 50 summarizes the results of the analysis. The Team contacted all the operators that had AMI, GLY, PNE, and PRE emissions units with the inaccurate number of hours entries and requested corrective actions (those bolded in Table 50). Operators of those facilities with erroneous entries revised their values and provided the correct ones.

> ***NOTE:*** The Team only contacted operators regarding those four equipment types (AMI, GLY, PNE, and PRE) because the number of hours of operation per month directly impacts the calculated emissions for those equipment types and would result in overestimation of the generated emissions. For other equipment types, the hours of operation per month were not mandatory and did not impact calculated emissions.

Table 50: Count of entries (number) having incorrect hours of operation per month by equipment type in the 2021 draft data (bold and asterisk types contacted for corrective action)

#	Type	Description	Monthly Records Having Incorrect Hours of Operation per Month	Contacted for Corrective Action
1	**AMI**	**Amine Unit***	**14***	**Contacted**
2	BOI	Boiler/Heater/Burner	5	-
3	DIE	Engine - Diesel or Gasoline Engine	12	-
4	DRI	Drilling Equipment	0	-
5	FLA	Combustion Flare–Flare	1	-
6	FLA	Combustion Flare–Pilot	N/A	-
7	FUG	Fugitives	N/A	-
8	**GLY**	**Glycol Dehydrator***	**55***	**Contacted**
9	LOA	Loading Operation	0	-
10	LOS	Losses from Flashing	5	-
11	MUD	Mud Degassing	0	-
12	NGE	Engine - Natural Gas	5	-
13	NGT	Turbine - Natural Gas, Diesel, or Dual Fuel	6	-
14	**PNE**	**Pneumatic Pump***	**6***	**Contacted**
15	**PRE**	**Pneumatic Controller***	**138***	**Contacted**
16	STO	Storage Tank	N/A	-
17	VEN	Cold Vent	12	-
-	**-**	**Total Count of Inaccurate Entries**	**254**	-

In future reporting cycles, the Team will mandate the hours of operation per month for all equipment types, and the QA checks will alert the users to the number of operating hours fields with values that exceed the maximum number of hours within a month, taking into account if the month has 31, 30, 28, or 29 (during leap years) days. In addition, copying operational hours and days from month to month will be prohibited to avoid similar issues in future reporting cycles.

4.6.2.5 Number of Operating Days in Month

The maximum range for the number of operating days in the month in OCS AQS was set to 31 for all 12 months in the 2021 reporting cycle. Although this is the highest possible number of days for some months, a lower maximum number of days in a month should have been set for others, such as February (28 or 29 days) and April, June, September, and November (30 days). If operators used the Copy Monthly Data feature in OCS AQS to fill in the activity values, then it was possible that some users would mistakenly copy the January data to the rest of the months and not correct the number of operating days for the months with fewer maximum allowable days.

A thorough analysis was conducted to identify the emission units with the wrong number of days under the months that do not have 31 days. Table 51 below summarizes the results of the analysis. The Team contacted all the companies that had emissions units with the inaccurate number of days entries and requested corrective actions. The companies revised their values and provided the correct ones.

OCS AQS has been updated to correctly apply the maximum number of days for each month. In future reporting cycles, the QA field will alert the user if the number of operating days in month fields exceed the number of actual days within each month. In addition, copying operational hours and days from month to month will be prohibited to avoid similar issues in future reporting cycles.

Table 51: Count of entries (number) having incorrect days of operation per month by equipment type in the 2021 draft data

#	Type	Description	Entries having Incorrect Days of Operation per Month
1	AMI	Amine Unit	N/A
2	BOI	Boiler/Heater/Burner	N/A
3	DIE	Engine - Diesel or Gasoline Engine	N/A
4	DRI	Drilling Equipment	N/A
5	FLA	Combustion Flare–Flare	N/A
6	FLA	Combustion Flare–Pilot	0
7	FUG	Fugitives	934
8	GLY	Glycol Dehydrator	N/A
9	LOA	Loading Operation	N/A
10	LOS	Losses from Flashing	N/A
11	MUD	Mud Degassing	0
12	NGE	Engine - Natural Gas	N/A
13	NGT	Turbine - Natural Gas, Diesel, or Dual Fuel	N/A
14	PNE	Pneumatic Pump	N/A
15	PRE	Pneumatic Controller	N/A
16	STO	Storage Tank	19
17	VEN	Cold Vent	N/A
		Total Count of Inaccurate Entries	**953**

4.6.3 Equipment Monthly Activity Data Consistency Checks

OCS AQS performs automated QA/QC checks to prevent users from calculating emissions with missing or incomplete mandatory activity data. These checks also prevent the users from submitting a facility (or whole inventory) containing missing or incomplete activity data. This check ensures that all inventories submitted through OCS AQS for the 2021 reporting year had complete mandatory activity data.

These data quality checks do have limitations. For example, they cannot verify the consistency of data within an emission unit across the 12 months. Some activity data, such as fuel sulfur content and fuel heating values, are not expected to change month to month, or even vary between different emission units within the same facility. The Team checked the consistency of fuel heating values and fuel sulfur content for all emission units with those two variables. Although a few instances of inconsistent heating values were found, these inconsistent values were within the typical range of fuel heating values. Therefore, the Team did not request any corrective actions for fixing those minor discrepancies.

Other variables, like throughputs (or any emission unit activity-related variables), are expected to vary month to month and might differ depending on the monthly emissions unit activity. Although mistyped values that are not representative of the actual activity on the platform can be expected, they cannot be easily identified. Therefore, the Team designed a new automated tool to detect such anomalies; the tool finds any entries that deviate from the non-zero 12-month average by a set of percentages the user can select from, depending on the variable and the case. This tool will highlight the anomalies and help the operator identify inconsistencies or mistyped values in the activity data.

The Team used this tool to identify emission units that had throughputs that deviated from the non-zero monthly average by more than 90%. However, since the operating hours were not mandatory for all emission units, it was not possible for the Team to determine whether the instances identified as a throughput anomaly were actual anomalies or reflected the actual higher or lower operating conditions during that month. Therefore, the Team decided not to set the companies with those emission units to corrective actions for this reporting cycle. Table 52 below shows the count of emission units by company that had entries deviating by 90% from the non-zero 12-month average.

In the future, the 2021 inventory data will serve as a baseline to compare the 2023 data to, allowing for tracking of the anomalies. This tool would also be available to the operators, and they would be able to use it to verify the quality of their own data, before submitting their inventories.

Table 52: Count of emission units (number) having throughputs deviating by 90% from the average by operating company in the 2021 draft data

#	Company Name	Emission Units Having Throughputs Deviating by 90% from the Average
1	Anadarko Petroleum Corporation	165
2	ANKOR Energy LLC	58
3	Arena Offshore, LP	146
4	BHP Billiton Petroleum (GOM) Inc	19
5	BP Exploration & Production Inc	59
6	Byron Energy Inc.	5
7	Cantium, LLC	47
8	Chevron USA Inc.	54
9	Contango Operators, Inc.	2
10	Cox Operating LLC	463

#	Company Name	Emission Units Having Throughputs Deviating by 90% from the Average
11	Destin Pipeline Company, L.L.C.	3
12	Energy XXI GOM, LLC	32
13	Eni US Operating Co. Inc.	33
14	Enven Energy Ventures	54
15	EPL Oil & Gas, Inc.	16
16	Equinor USA E&P Inc.	11
17	Exxon Mobil Corporation	11
18	ExxonMobil Pipeline	1
19	Fieldwood Energy Offshore LLC	145
20	Fieldwood Energy, LLC	448
21	Fieldwood SD Offshore LLC	4
22	Flextrend Development Company, LLC	2
23	GOM Shelf LLC	96
24	GoMex Energy Offshore, Ltd.	3
25	Helis Oil & Gas Company, LLC	5
26	Hess Corporation	42
27	High Point Gas Gathering, L.L.C.	7
28	LLOG Exploration Offshore, L.L.C.	14
29	Manta Ray Gathering Company, LLC	20
30	MC Offshore Petroleum, LLC	20
31	Monforte Exploration L.L.C.	9
32	Murphy Exploration & Production Company - USA	65
33	Peregrine Oil and Gas II, LLC	1
34	Renaissance Offshore, LLC	88
35	Ridgelake Energy, Inc.	15
36	Sanare Energy Partners, LLC	15
37	Sea Robin Pipeline Company, LLC	8
38	Shell Offshore Inc.	90
39	Shell Pipeline Company LP	22
40	Talos Energy Offshore, LLC	52
41	Talos ERT LLC	55
42	Talos Oil and Gas LLC	9
43	Talos Petroleum LLC	90
44	Talos Third Coast LLC	21
45	TANA Exploration Company, LLC	2
46	Transcontinental Gas Pipe Line Company, LLC	7
47	W & T Energy VI, LLC	20
48	W&T Offshore, Inc.	140
49	Walter Oil & Gas Corporation	43
50	Whitney Oil & Gas, LLC	9
51	Williams Oil Gathering, LLC	1

4.6.4 Flat Emissions Checks

If an emission unit operates consistently throughout the year, its monthly calculated emissions would be flat (i.e., non-variable) and without monthly variations. Changes in the platform activities from one month to another are expected, since some months have fewer operating days/hours, and some might incorporate special events, which can impact operating activities, such as maintenance. Flat emissions could also result from using the copy monthly data feature in OCS AQS, where activity data is copied from one month to multiple others. The Team located some issues related to the use of this feature without addressing the variations in the activity data variables, such as copying operating hours from longer months to the shorter ones. This issue was addressed and discussed in detail in Section 4.6.2.4, where it was mentioned that copying operational hours and days from month to month will be prohibited in future reporting cycles, ensuring that the operators will take into account at least temporal monthly variations.

As an additional safeguard, the "Highlight Flat Emissions" feature was introduced to the monthly emissions data grid in OCS AQS, which will help identify emission units with flat emissions in future reporting cycles.

4.6.5 Stream Analysis

In OCS AQS, certain emission units have an emissions destination drop-down field in their data request tab in the Activity and Emissions Manager. Operators can select the emissions to be vented locally, vented remotely, flared locally, flared remotely, or routed to the system. Emissions are calculated under the process if the destination is selected as vented locally; however, any other selection will set emissions to zero at the process level. For emissions vented or flared remotely, operators are responsible for accounting for the emissions under cold vents or combustion flares, respectively. Table 53 summarizes the count of processes that reported emissions as non-vented locally by equipment type in the 2021 inventory.

The Team performed a stream analysis on emissions vented and flared remotely. The approach in this analysis was to verify that a facility with an emission unit that vents or flares remotely has a corresponding vent or flare associated with it. Table 54 summarizes the results of that analysis. There were four instances (at four separate facilities) where an emission unit had emissions vented remotely, but there was no corresponding vent under the same facility.

For some emission units, although the facility did not have an associated vent or flare, operators added a comment and clarified that emissions were sent to another facility and explicitly identified that facility. However, for emission units in Table 54, the users did not provide any such information, and the Team contacted the facilities to request further details to fix this issue.

The operator of Facility ID# 21786-4, which belongs to Cox Operating LLC, confirmed that FLASH-01 vented its emissions to a cold vent located on Facility ID# 21786-8 and that those flash emissions were accounted for under that vent. Similarly, Facility ID# 2103-3 verified that its glycol dehydrator emission unit vented its emission to a vent at Facility ID# 2103-1. Therefore, the Team confirmed the existence of cold vent emission units at the facilities specified by the operators, to ensure the quality of data in the 2021 inventory.

The operators of Facilities IDs# 1218-1 and 1799-1, which belong to W&T Offshore, Inc. and Enven Energy Ventures, respectively, confirmed that the emissions from their emission units listed in Table 54 were flared remotely, not vented remotely, and that they needed their facilities to be set to corrective action so they could fix the issue. Therefore, the Team first confirmed that those facilities (1218-1 and 1799-1) have flares and then set them to corrective action to fix their erroneous emissions destination. All necessary stream analysis corrections were updated for the 2021 final inventory.

Table 53: Count of emissions destination entries (number) by equipment type in the 2021 draft data

#	Type	Description	Vented Remotely	Flared Locally	Flared Remotely
1	AMI	Amine Unit	0	2	34
2	BOI	Boiler/Heater/Burner	0	0	0
3	DIE	Engine - Diesel or Gasoline Engine	12	0	0
4	DRI	Drilling Equipment	0	0	0
5	FLA	Combustion Flare	N/A	N/A	N/A
6	FUG	Fugitives	N/A	N/A	N/A
7	GLY	Glycol Dehydrator	99	12	0
8	LOA	Loading Operation	0	0	0
9	LOS	Losses from Flashing	2,222	0	0
10	MUD	Mud Degassing	0	0	0
11	NGE	Engine - Natural Gas	0	0	0
12	NGT	Turbine - Natural Gas, Diesel, or Dual Fuel	0	0	0
13	PNE	Pneumatic Pump	287	13	0
14	PRE	Pneumatic Controller	0	0	0
15	STO	Storage Tank	949	0	0
16	VEN	Cold Vent	0	0	0

Table 54: Stream analysis emissions destination results per month in the 2021 draft data

Company Name	Facility ID	Emission Unit	Process	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cox Operating LLC	21786-4	FLASH-01	LOS	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR
W&T Offshore, Inc.	1218-1	T-01	STO	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR
Contango Operators, Inc.	2103-3	GLYCOL	GLY	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR	VR
Enven Energy Ventures	1799-1	MAF-3050	GLY	-	-	-	-	-	-	-	VR	VR	VR	VR	VR

VR = Vented Remotely

4.6.6 QA/QC Comments

In OCS AQS, entering out-of-range data is prohibited. The automated QA/QC checks flag out-of-range data and do not allow calculating emissions or submitting the emissions inventory. Nonetheless, submitting out-of-range data without flags is allowed <u>if and only if</u> operators explain those values under the linked QA comment tab in the data request fields. This process allows the Team to review the comments and decide whether the provided out-of-range value is legitimate or requires revisions.

In the OCS AQS Reports module, the QA/QC Comments report summarizes all the operators' QA/QC comments on the data request fields. As part of the QA/QC efforts, the Team generated this report for the 2021 draft inventory data to assess the comments and verify their accuracy.

Using the generated report, the Team identified QA/QC comments on the number of days in the month field under a pilot flare process belonging to Facility ID# 2089-1 under company Equinor USA E&P Inc. Figure 8 is a screenshot of the generated QA/QC Comments Report and shows the comments entered for the three fields.

The comments state that the "Platform shut in following Hurricane Ida," which means the platform was not generating emissions during those three months because of Hurricane Ida, which occurred in late August 2021. However, the operator provided the activity data and calculated emissions with those provided comments.

The Team contacted the operator and explained that if the platform was not emitting during those months, an option to zero out emissions is available in OCS AQS by clicking the Facility-Wide Zero Emissions button and selecting "Destroyed by hurricane in reporting year" as the reason for the three months of inactivity. The operator requested corrective action, zeroed-out emissions properly using the Facility-Wide Zero Emissions feature in OCS AQS and recalculated emissions.

> ***NOTE:*** In future reporting cycles, the feature of providing out-of-range activity data by entering a comment will be disabled, and if an operator needs to enter a value that is not within the range specified, they will need to contact the OCS AQS technical support first to review the value.

OCSAQS
The Outer Continental Shelf Air Quality System

QA/QC Comments

Facility: (Titan) (2089-1)
Equipment: FLA001 - Combustion Flare - Pilot - FLA-Pilot -

Field	Value	Month	Request Type	Comment
Number of Days in Month [Day]:	30	September	Data Request	Platform shut in following Hurricane Ida
Number of Days in Month [Day]:	31	October	Data Request	Platform shut in following Hurricane Ida
Number of Days in Month [Day]:	30	November	Data Request	Platform shut in following Hurricane Ida

Figure 8: Screenshot of the QA/QC comments report

5 EFs and Revised Calculation Methods (Platform Sources)

5.1 EF Comparison

Initial configuration of OCS AQS to support the 2021 emissions inventory effort utilized EFs from the *Year 2017 Emissions Inventory Study* (Wilson et al. 2019). In 2021, the original 2017 EFs in OCS AQS were updated using the latest information available from the USEPA's AP-42 compilation of EFs, which can be found at https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.

The EFs comparison methodology is summarized as follows:

1. The 2017 EFs were compared against the March 2022 version of USEPA's AP-42 EFs. The EFs used in 2017 were based on the *Year 2017 Emissions Inventory Study*. As a result of the comparison, the Team revised five EFs were revised (Table 55).
2. The five EFs (Table 55) were corrected and updated in OCS AQS for operators to use in the 2021 effort.
3. All the calculation methods in OCS AQS utilizing the corrected EFs were externally validated by the Team.

Table 55 lists the EFs that required corrections.

Table 55: Summary of EFs corrected for the 2021 effort

Emissions Calculation Method	Pollutant	EF (2017)	EF (2021)	Units
Diesel Engines Where Max HP < 600	VOC	0.33	0.36	lb/MMBtu
Diesel Engines Where Max HP ≥ 600	$PM_{2.5}$	0.056	0.0479	lb/MMBtu
Drilling Equipment (Diesel Fuel Use)	VOC	0.08	0.0819	lb/MMBtu
Combustion Flares	CO_2	114.285	117.65	lb/MMBtu
Combustion Flares-Pilot	Pb	0.005	0.0005	lb/MMscf

Table 55 summarizes the differences in EFs between the 2017 and 2021 inventories. The review confirmed that the EFs used in the 2021 effort are accurate and reflect the data published on the AP-42 website.

Two examples (e.g., CO_2 and Pb EFs for Combustion Flares) are provided below illustrating how the Team identified and corrected the erroneous EFs.

5.1.1 Carbon Dioxide (CO_2) in Combustion Flares

The CO_2 Combustion Flares EF for the flaring process published in the *Year 2017 Emissions Inventory Study* (Table 4-12, Page 29) equals 114.285 lb/MMBtu (Wilson et al. 2019). A footnote in that report states that "[f]actors for N_2O and CO_2 were derived from pilot emissions factors." Converting the pilot CO_2 EF 120,000.0 lb/MMscf to an energy basis (lb/MMBtu) does not equal 114.285 lb/MMBtu as per the calculation below.

Converting a volume basis (lb/MMscf) to an energy basis (lb/MMBtu) is done by dividing by a heating value of 1,020 MMBtu/MMscf:

[120,000.0 lb/MMscf] / [1,020 MMBtu/MMscf] = 117.65 lb/MMBtu

As a result, the Team updated the CO_2 Combustion Flares EF value. This increase in the 2021 CO_2 combustion flares EF value would result in an increase of CO_2 emissions from 2017 final to 2021 draft data by a factor of 3.37, provided the activity data and the number of emission units is the same. However, this is not the case because the number of reported combustion flares in the 2017 final data was 90; in the 2021 draft data, operators reported a total number of 114 combustion flares, which did not clearly reflect the impact of the EF discrepancy (other factors resulted in the emissions discrepancies) (see Section 6.5.1).

5.1.2 Lead (Pb) in Combustion Flares

The Pb EF in combustion flares published in the *Year 2017 Emissions Inventory Study* (Table 4-13, page 29) equals 5.0E-03 lb/MMscf (Wilson et al. 2019). However, when the Team reviewed the AP-42 EF values, the published EF value was 5.0E-04 lb/MMscf. This value was incorporated into OCS AQS. This considerable decrease in the EF value from 2017 final data to 2021 draft data would result in a reduction of 10% of Pb emissions, provided all other parameters held constant (i.e., activity data and number of emission units). As described above, the number of Combustion Flares in the 2017 final data varies from the number of reported Combustion Flares in the 2021 draft data. Overall, the Pb emissions from Combustion Flares were less. Collectively, for Combustion Flares, operators reported 5.44E-05 tons of Pb in the 2021 draft data, and 8.46E-05 tons in the 2017 final data. These numbers yield a 36% decrease in Pb emissions from Combustion Flares in the 2021 reporting year.

5.2 Revised Calculation Methods

5.2.1 Storage Tanks

Storage tanks calculators in OCS AQS use the equations from the latest version of AP-42's Chapter 7: Liquid Storage Tanks (USEPA 2022). In OCS AQS, four storage tank calculators are designed based on the storage tank orientation (Horizontal/Vertical) and type (Rectangular/ Cylindrical). All conditions and rules provided in AP-42's Chapter 7 are strictly followed. The tool considers the state and paint of the storage tanks, their roof type and shape, and their processed material (Section 3.2.15).

In contrast, storage tank emissions in the 2017 final inventory were estimated using the methods provided in the *Year 2017 Emissions Inventory Study* document (Wilson et al. 2019). The EF methodologies provided in section 4.2.15 of that document were outdated and do not follow the most recent methodologies as published in AP-42 (USEPA 2022). Thus, emissions from storage tanks can potentially differ when comparing 2017 final to 2021 draft inventories, as any minor changes in calculation methods will subsequently affect the final calculated losses and emissions.

> ***NOTE:*** Please note that the calculations in the *Year 2017 Emissions Inventory Study* document are current except for 4.2.15.

5.2.2 Diesel Turbines

In section 4.2.12 of the *Year 2017 Emissions Inventory Study* document (Wilson et al. 2019), the following equation was used to estimate natural gas, diesel, and dual-fuel turbines emissions:

$$E_{fu} = EF_{(lb/MMBtu)} \times 10^{-3} \times H \times U \qquad (Eq. 69)$$

where:

E_{fu} = Emissions in $lb/month$

EF = Emission factor in in $lb/MMBtu$

H = Fuel heating value in Btu/scf

U = Fuel usage in $Mscf/Month$

In OCS AQS, however, the above equation was only used for estimating emissions from NGT. For diesel turbines, the following equation, from section 4.2.4 of the *Year 2017 Emissions Inventory Study* document (Wilson et al. 2019), was used instead:

$$E_{die} = EF_{(lb/MMBtu)} \times 10^{-6} \times U \times 7.1\ lb/gal \times 19{,}300 \qquad (Eq. 70)$$

where:

E_{die} = Emissions from diesel turbines in $lb/Month$

EF = Emission factor in $lb/MMBtu$

U = Fuel usage in $gal/Month$

7.1 is the diesel density (conversion factor from gal to lb)

19,300 is the default diesel heating value in Btu/lb

The above equation was used primarily to avoid any possible confusion coming from unit conversion. Furthermore, using the diesel default heating value, rather than requiring the user to provide it, simplified the users' data-entry process and will assure more reliable and accurate data.

Since users in the 2017 reporting cycle provided the heating value, the usage of the system default value is expected to contribute to minor discrepancies in diesel turbine emissions. Nevertheless, when analyzing 2017 data, we found that 60% of the 2017 diesel equipment used the value of 19,300 for heating value; this percentage supports our default value selection.

> ***NOTE***: The 19,300-heating value was also used as the surrogate value for missing values in the 2017 inventory; see Table 4-1 in Wilson et al. (2019).

6 Comparison to 2017 Inventory (Platform Sources)

To document abnormal and unexpected trends and conduct further QA/QC, the Team conducted a comparison between the 2017 final and 2021 draft inventory. According to the *Year 2017 Emissions Inventory Study*, during the 2017 reporting cycle, 57 companies submitted data for a total of 1,842 platforms, of which 1,194[4] of them were operating (Wilson et al. 2019). Conversely, the 2021 complete inventory in OCS AQS incorporated a total 1,738 platforms, 982 of them operating and belonging to 56 companies—not including the operating platforms omitted from the 2021 inventory. There are several possible reasons for those changes in the count of the companies and their platforms between inventory years. These changes may be due to an actual decline in the number of the operating platforms in 2021 or due to some operators not reporting their emissions for some platforms in the 2021 inventory (15 platforms were not submitted to and 81 were missing from the OCS AQS 2021 inventory, see Section 4.4 for details). These discrepancies in the number of operating platforms can lead to other differences related to the count of emission units, types of emitted pollutants, and total annual emissions. At the same time, actual year-to-year variations in operational activities on the platforms also may contribute to variations in the calculated emissions. For example, on August 29, 2021, Hurricane Ida made landfall near Port Fourchon, Louisiana, as a Category 4 hurricane. As a result, according to BSEE estimates, 96% of crude oil production and 94% of natural gas production in the U.S. federally administered areas of the GOM were shut in between one week to several months depending on severity of the damage and the logistics require to complete repairs and transport staff to the platforms to restart operations.

The following sections summarize how the Team analyzed and verified several factors to ensure the reliability of the 2021 submitted inventory and drew additional conclusions regarding which changing factors resulted in increases or decreases in emissions between 2017 and 2021. Those verifications were performed by evaluating the 2021 data and/or by comparing them to the 2017 inventory activity data and calculated emissions. Comparisons to 2017 data can help detect unexpected anomalies in the emissions or activity data and generally gives an overview of the usual platform trends and their activities. As a result of those investigations, corrective actions and re-submissions were requested from operators, depending on the issues discovered.

6.1 Platform Count by OPD Area

The comparison tables in Sections 6.1, 6.2, 6.3, and 6.4 serve as a starting point for the comparative analysis of emissions for the 2017 and 2021 reporting years. The analysis, conducted in the following sections, helps to identify abnormal activity resulting in large discrepancies between the two inventory years or detect data entry errors in activity data to be fixed.

As presented in Table 56, 982 operating platforms in the 2021 inventory are distributed throughout the GOM and located within 33 OPD areas. Approximately 50% of the 2021 platforms are located in four OPD areas, specifically, the Ship Shoal (SS), Eugene Island (EI), South Marsh Island (SM), and South Timbalier (ST) areas (Table 56). Figure 9 is the visual representation of the same data and shows the variations between 2021 and 2017 platform counts by OPD area.

[4] In the 2017 final inventory in OCS AQS, there are 1,195 operating facilities. The additional facility is Facility ID# 940-1A, which is under company ExxonMobil Pipeline. This facility is the leased portion of Facility ID# 940-1 under company Williams Oil Gathering, LLC.

Table 56: Operating platform count (number) by OPD area by inventory year with % of total

#	OPD Area	2017 Final	2021 Draft	Percentage of Total 2021[a]
1	SS (Ship Shoal)	191	145	14.766%
2	EI (Eugene Island)	147	124	12.627%
3	MP (Main Pass)	105	114	11.609%
4	ST (South Timbalier)	104	108	10.998%
5	SM (South Marsh Island)	120	97	9.878%
6	WD (West Delta)	64	67	6.823%
7	SP (South Pass)	35	39	3.971%
8	VR (Vermilion)	69	39	3.971%
9	GI (Grand Isle)	40	38	3.870%
10	WC (West Cameron)	69	31	3.157%
11	HI (High Island)	51	27	2.749%
12	GC (Green Canyon)	19	22	2.240%
13	MC (Mississippi Canyon)	23	22	2.240%
14	MO (Mobile)	17	17	1.731%
15	EC (East Cameron)	22	12	1.222%
16	VK (Viosca Knoll)	15	11	1.120%
17	PL (South Pelto)	29	10	1.018%
18	BS (Breton Sound)	6	9	0.916%
19	BM (Bay Marchand)	6	8	0.815%
20	GA (Galveston)	11	8	0.815%
21	EW (Ewing Bank)	7	7	0.713%
22	GB (Garden Banks)	7	7	0.713%
23	BA (Brazos)	10	6	0.611%
24	WR (Walker Ridge)	3	4	0.407%
25	EB (East Breaks)	5	3	0.305%
26	AC (Alaminos Canyon)	2	2	0.204%
27	PN (North Padre Island)	3	2	0.204%
28	CA (Chandeleur)	1	1	0.102%
29	KC (Keathley Canyon)	1	1	0.102%
30	MU (Mustang Island)	2	1	0.102%
31	MI (Matagorda Island)	10	0	0.000%
32	SA (Sabine Pass (Louisiana))	1	0	0.000%
-	**Total Operating platforms**	**1,195**	**982**	**100%**

Notes: [a] $Percentage\ of\ Total\ 2021 = \frac{\text{Draft 2021 Count of Operating Platforms by OPD Area}}{\text{Total Count of Draft 2021 Operating Platforms}} \times 100\%$

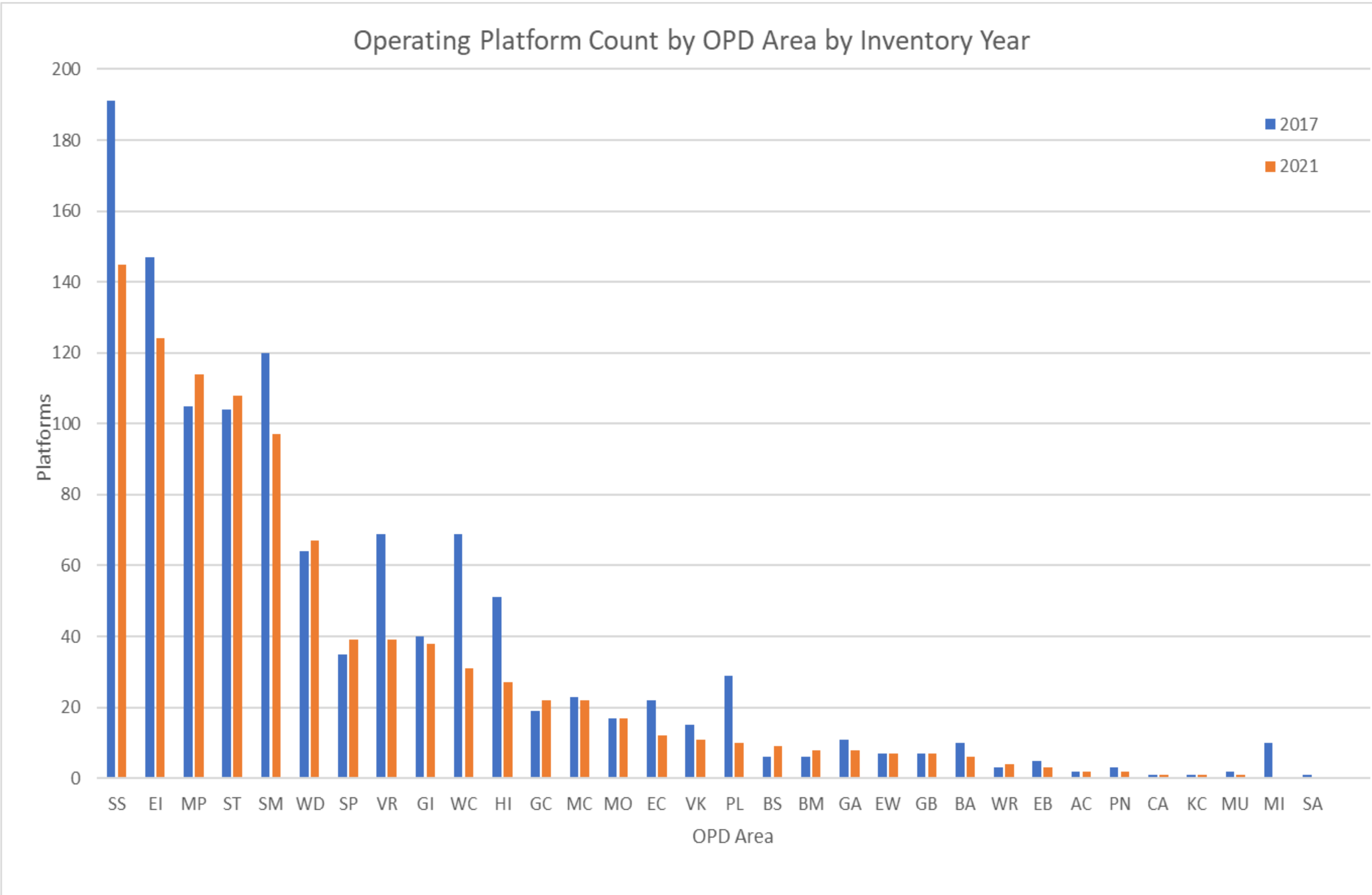


Figure 9: Operating platform count by OPD area by inventory year with 2017 (blue, left columns) and 2021 (orange, right columns)
See Table 54 for OPD Abbreviations Key.

6.2 Platform Count by Structure Type

This section provides a summary of operating platform counts by structure type. As demonstrated in Table 57, the fixed leg platform is the dominant structure type in both 2021 and 2017. Figure 10 provides a visual representation of the same data.

Table 57: Operating platform count (number) by structure type by inventory year

Structure Type	Description[a]	2017 Final	2021 Draft	Percentage of Total 2021[b]
FIXED	Fixed Leg Platform	969	758	77.2%
SPAR	SPAR Platform - Floating Production System	173	155	15.8%
WP	Well Protector	18	18	1.8%
SEMI	Semi Submersible (Column Stabilized Unit) Floating Production System	12	14	1.4%
CAIS	Caisson	10	12	1.2%
TLP	Tension Leg Platform	4	4	0.4%
MTLP	Mini Tension Leg Platform	3	16	1.6%
FPSO	Floating Production, Storage, And Offloading	3	2	0.2%
CT	Compliant Tower	2	2	0.2%
MOPU	Mobile Production Unit	1	1	0.1%

Notes: [a] Structure Type Description is from Platform Structures Online Query Field Definitions from the BOEM Data Center: https://www.data.boem.gov/Platform/PlatformStructures/FieldDefinitions.aspx

[b] $Percentage\ of\ Total\ 2021 = \frac{\text{Draft 2021 Count of Operating Platforms by Structure Type}}{\text{Total Count of Draft 2021 Operating Platforms}} \times 100\%$

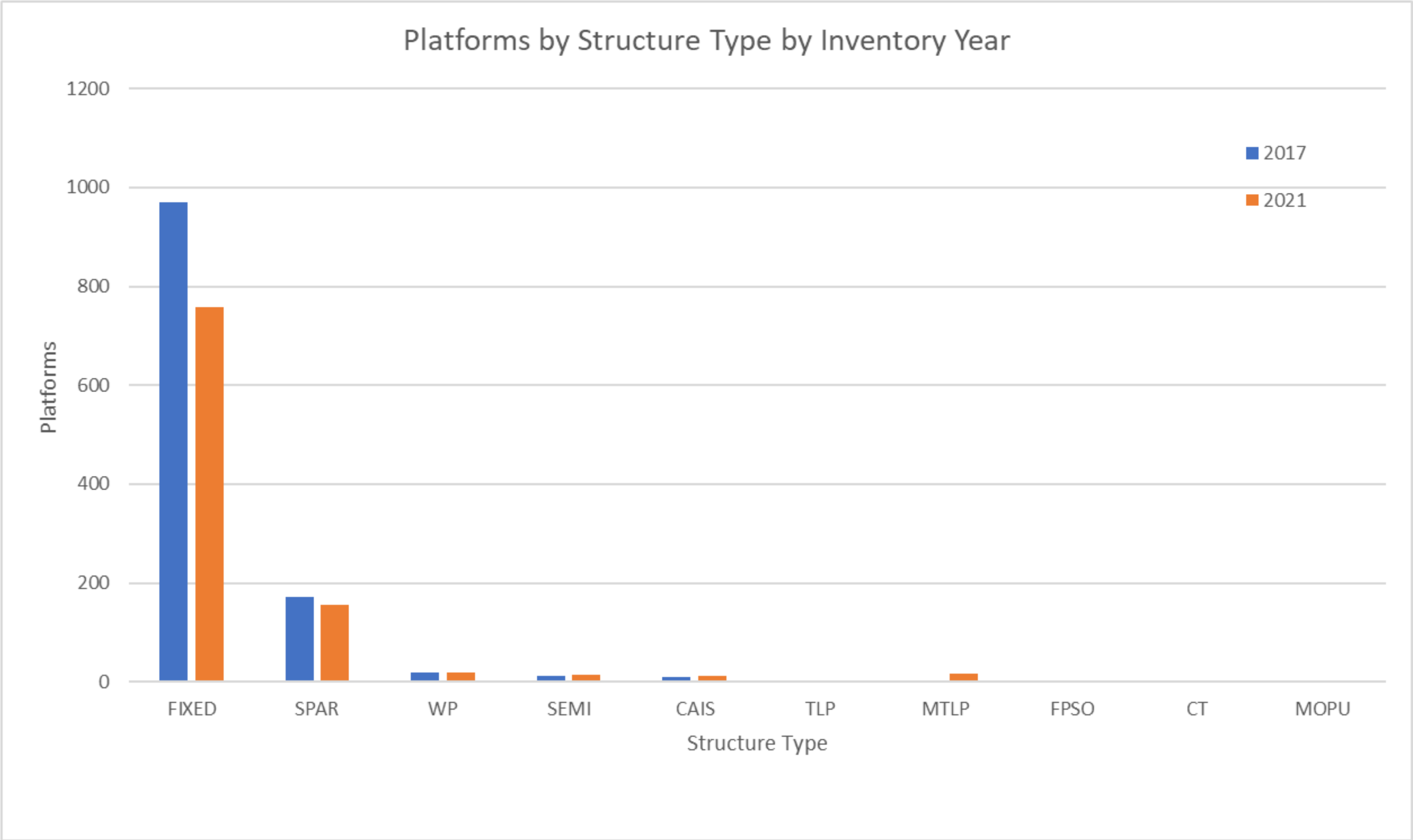


Figure 10: Operating platform count by structure type by inventory year with 2017 (blue, left columns) and 2021 (orange, right columns)
See Table 55 for the Structure Type Abbreviations Key.

6.3 Platform Count by Water Depth

This section provides a summary of operating platform count by shallow or deep water. As defined by BOEM, any areas with water depths greater than 1,000 feet (305 m) is considered "deepwater" (Wilson et al. 2019). As demonstrated in Table 58, 94% of 2021 draft operating platforms are in shallow water. Figure 11 provides a visual representation of the same data.

It is important to note that the Team identified 37 platforms missing the water depth values (33 operating platforms + 4 not operating [temporarily or permanently shut down]). As part of the QA/QC efforts, the Team filled in the missing water depths using the published data in the BOEM data center found in the Platform Structures Online Query. As an additional verification step, the Team compared all the entered water depths in OCS AQS to the BOEM data center data. A total of 14 platforms in OCS AQS had water depths entered incorrectly—the OCS AQS values did not match the values in the public database. The Team also took into consideration those findings and adjusted the values to match the published values. For example, Facility ID# 20049-2 had a value of 48 ft in OCS AQS, while the value in the BOEM's database was 50; the Team adjusted the value to 50 ft.

Table 58: Operating platform count (number) by shallow/deep water distinction by inventory year

Water Depth	2017 Final	2021 Draft	Percentage of Total 2021[a]
Shallow	1,139	923	94.0%
Deep	56	59	6.0%

Notes: [a] $Percentage\ of\ Total\ 2021 = \frac{\text{Draft 2021 Count of Operating Platforms by Water Depth}}{\text{Total Count of Draft 2021 Operating Platforms}} \times 100\%$

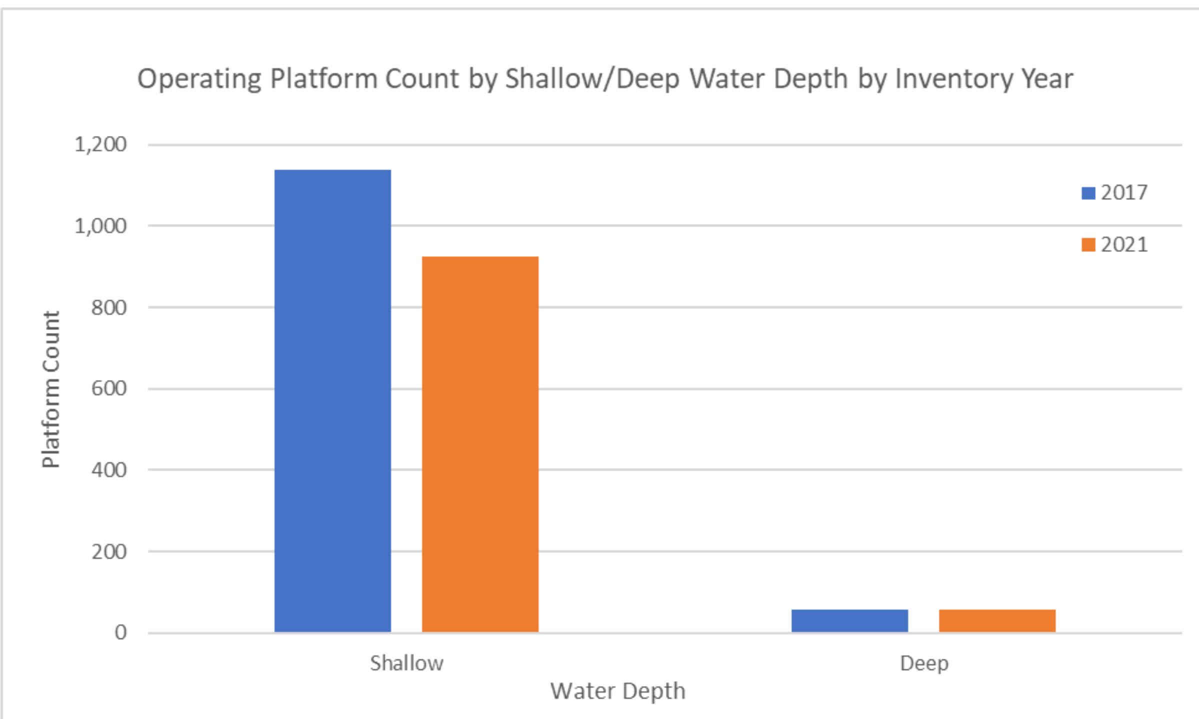


Figure 11: Operating platform count by shallow/deep water depth by inventory year with 2017 (blue, left columns) and 2021 (orange, right columns)

6.4 Platform Emissions by OPD Area

Using the OCS AQS Analytics module, we generated Figure 12 and Figure 13 to visualize greenhouse gas (GHG) emissions by OPD area for the 2017 final inventory and 2021 draft inventory. As shown in both figures, Mississippi Canyon (MC) area had the highest annual emission of CO_2-E in 2021 and 2017. However, as previously presented in Table 56, MC did not have the highest count of operating platforms; this area had 24 and 23 platforms in 2021 and 2017, respectively. Table 59 is part of the table generated by the OCS AQS Annual Facility Pollutant Totals – Highest Emitters report for CO_2-E in 2021. As shown, 6 out of 10 highest CO_2-E emitting facilities are in the MC area. Cumulatively, those six facilities made the MC area have the highest emissions of CO_2-E. Those high values of CO_2-E could have resulted from extensive operational activities at those facilities or inaccurate activity data. We conducted deeper analysis of emissions and equipment types in the following sections to further document issues in the activity data.

From Figure 13, the analysis showed a noticeable dip in the 2021 draft CO_2-E emissions in September. This dip is likely due to Hurricane Ida, which crossed the Gulf near Port Fourchon, Louisiana, as a Category 4 from August 26–September 5, 2021. Two hurricanes passed through the region in 2017 in August and September: Hurricane Harvey (August 17–September 1, 2017) passed through the western Gulf as a Category 2 and reached category 4 prior to making landfall, and Hurricane Irma (August 30–September 12, 2017) entered the eastern GOM as category 4; however, there was minimal disruption to total production for September in 2017 (Wilson et al. 2019). This can be seen in Figure 12, where the dip in September emissions is minimal compared to the clear dip in September in Figure 13. This is likely because both Harvey and Irma hurricanes in 2017 cut through the Gulf in areas with few active platforms (Wilson et al. 2019). There was, however, a slight dip in 2017 October emissions due to the disruption of production caused by Hurricane Nate (October 4–8, 2017), which took place in the central Gulf as a Category 1 storm by the end of the hurricane season (Wilson et al. 2019).

> ***NOTE:*** The CO_2-E values are obtained by multiplying the GHG emissions by their global warming potential (GWP) factors. In the 2017 final and 2021 draft inventory years, GWP factors were 1, 25, and 298 for CO_2, CH_4, and N_2O, respectively.

Table 59: Highest CO_2-E emitting facilities (tons/year) in the 2021 draft data

#	Facility ID	Facility Name	Company Name	Area/Block ID	Annual Emissions (Tons)
1	2623-1	A-Appomattox	Shell Offshore Inc.	MC437	285,628.33
2	1101-1	A - Thunder Horse	BP Exploration & Production Inc.	MC778	249,964.73
3	2008-1	A-Perdido	Shell Offshore Inc.	AC857	248,613.47
4	1223-1	A-Atlantis	BP Exploration & Production Inc.	GC787	240,390.18
5	2440-1	A	Chevron USA Inc.	WR718	200,362.88
6	70004-1	A-Ursa TLP	Shell Offshore Inc.	MC809	195,603.13
7	24199-1	A-Mars TLP	Shell Offshore Inc.	MC807	164,442.62
8	2660-1	A	Hess Corporation	GC468	148,146.94
9	1001-1	Nakika	BP Exploration & Production Inc.	MC474	147,039.04
10	1175-1	A	Eni US Operating Co. Inc.	MC773	138,035.06

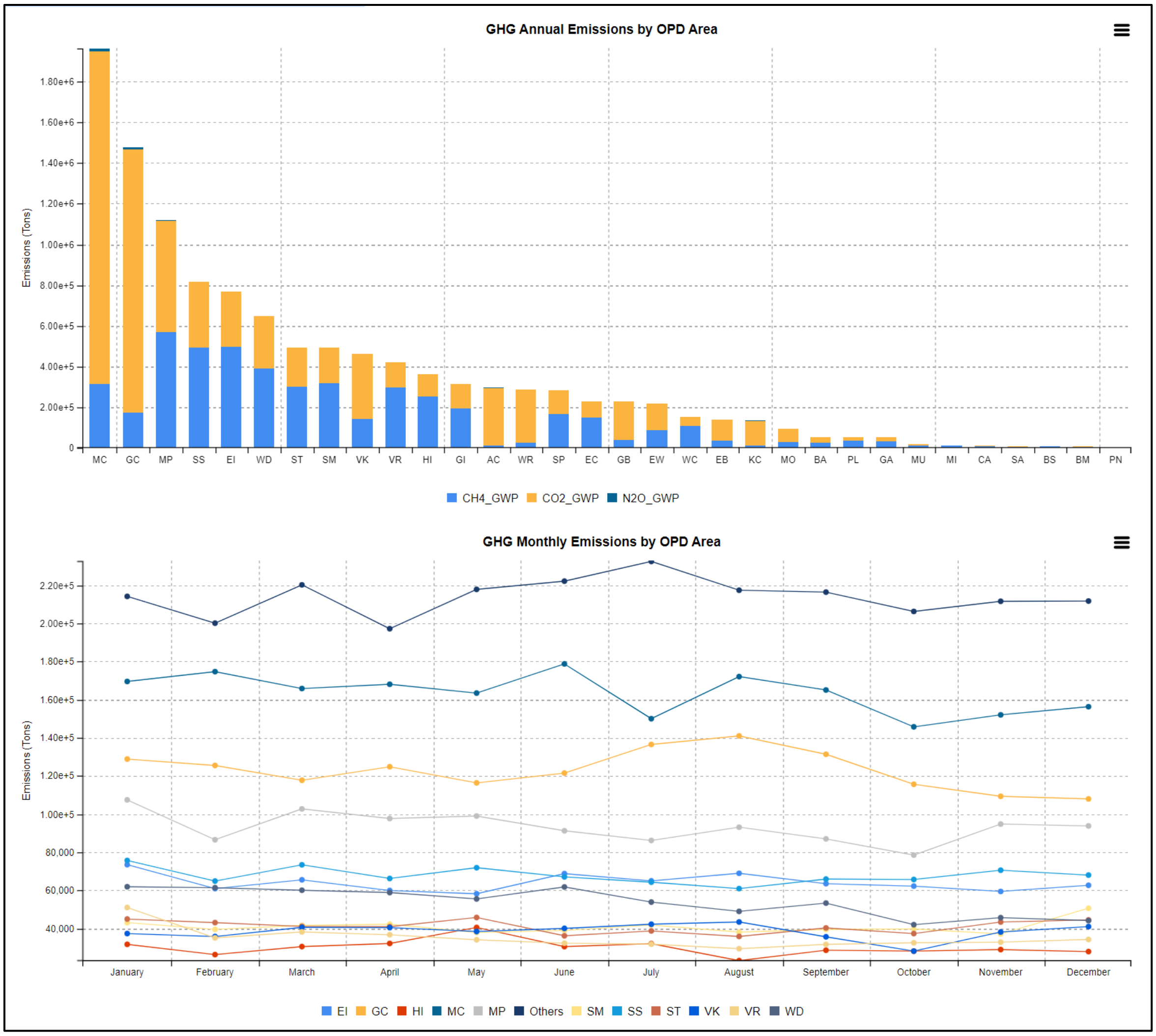


Figure 12: 2017 final GHG emissions (tons) by OPD area from the OCS AQS Analytics Module
See Table 54 for OPD Abbreviations Key.

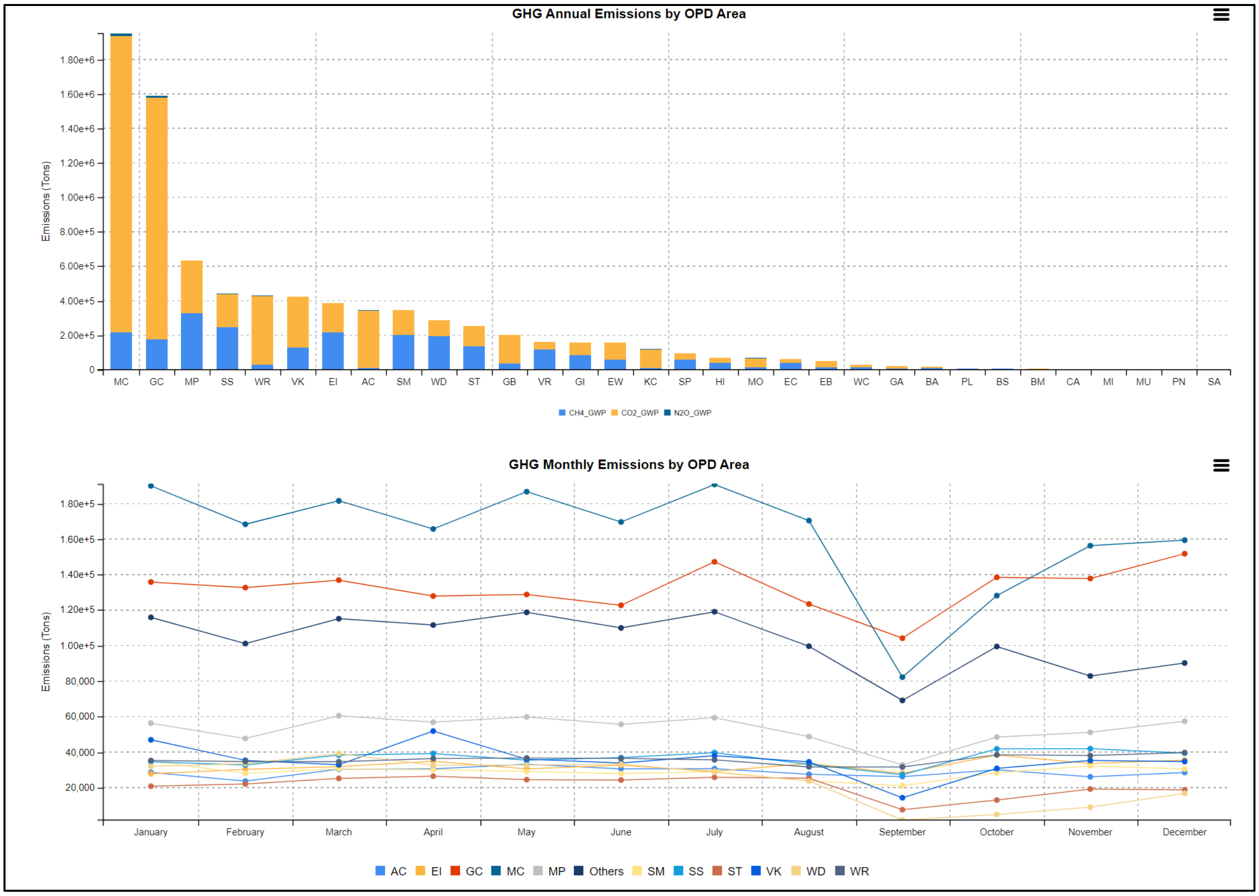


Figure 13: 2021 draft GHG emissions by OPD area from the OCS AQS Analytics Module
See Table 54 for OPD Abbreviations Key.

6.5 Platform Emissions by Pollutants

Table 60 shows data exported from the inventory analysis tab in the Data Analytics Dashboard in OCS AQS. It provides an overview of the calculated emissions in the previous and current inventories (specifically, 2017 final and 2021 draft [July 2022 version] with some initial QA/QC).

> ***NOTE:*** The Data Analytics dashboard and the Analytics module are tools developed by the Team specifically to aid in the 2021 QA/QC effort. These tools were used extensively in the preparation of this document and will be referred to in the following sections. In the future reporting cycles, the Analytics module will be available to both BOEM and operators, while the Data Analytics dashboard will only be available to BOEM, as it is used to audit aggregated data to which only administrative users have access.

If large discrepancies were found, data in this table serve as the basis for the sections that followed, where the 2021 draft emissions for each pollutant in question were extensively analyzed and compared with the 2017 final emissions to investigate the underlying reason for the significant changes observed. The “see Section” column in Table 60 guides the reader to the specific analysis of each pollutant.

Throughout this section, the following terminology is used to describe percentage change:

- Minimal: 0–15%
- Moderate: 15–50%
- Considerable: 50–100%
- Extensive: 100%+

It is important to note that emissions by pollutants in this section are analyzed on a high level; only equipment types contributing the most to the total emissions of a pollutant are investigated deeply to identify the dominant underlying reasons for high discrepancies between the calculated emission in the two inventory years (2017 final and 2021 draft); not all equipment types are analyzed or investigated. All equipment types have contributed to the change or discrepancies in emissions, but the focus of this section is on the highest contributor only. In Section 6.6, emissions by equipment type by inventory are analyzed and compared to identify less apparent issues under the different equipment types contributing to the changes (discrepancies) in the 2021 draft emissions inventory.

> ***NOTE:*** 2021 draft emissions analyzed in this section are from the 2021 inventory dated July 14, 2022. Therefore, all comparisons in this section are based on emissions dated on this date, including any corrective action received and incorporated into the draft inventory.

> ***NOTE:*** In this section and Sections 4.6 and 6.6, various data input-entry errors were identified, and different operators requested corrective actions to address and correct those issues. All those corrective actions changed the final calculated emissions (increased or decreased, depending on the situation). As a result, the 2021 final emissions are represented and discussed in Section 8 to incorporate all the corrective actions requested in Sections 4.6, 6.5 and 6.6.

Table 60: Platform emissions (tons/year) by pollutant by inventory year with 2021 draft data as of July 2022

#	Pollutant	2017 Final	2021 Draft	Difference	% Change[a]	See Section
1	Sulfur Dioxide (SO_2)	462.055	1,534.591	1,072.536	+ 232.12%	6.5.5
2	Carbon Dioxide (CO_2)	6,857,359.61	15,793,642.6	8,936,282.98	+130.32%	6.5.1
3	Arsenic	0.0026	0.0041	0.0015	+ 57.83%	6.5.14
4	Carbon Dioxide Equivalent (CO_2E)	11,589,943.1	18,228,399.3	6,638,456.17	+ 57.28%	6.5.4
5	Lead	0.0038	0.0056	0.0018	+ 47.38%	6.5.12
6	Beryllium	0.000086565	0.00012506	0.000038499	+ 44.47%	6.5.15
7	Acetaldehyde	155.005	213.211	58.206	+ 37.55%	6.5.21
8	Chromium (VI)	0.019	0.0206	0.0016	+ 8.43%	6.5.16
9	Chromium III	0.4479	0.4817	0.0338	+ 7.54%	6.5.17
10	Mercury	0.2309	0.2477	0.0168	+ 7.27%	6.5.18
11	Cadmium	0.2441	0.2613	0.0172	+ 7.06%	6.5.19
12	Nitrous Oxide (N_2O)	118.21	121.196	2.986	+ 2.53%	6.5.3
13	Volatile Organic Compound (VOC)	38,832.769	39,727.642	894.873	+ 2.30%	6.5.10
14	2,2,4-Trimethylpentane	9.619	8.517	-1.102	- 11.45%	6.5.23
15	Hexane	765.512	617.415	-148.097	- 19.35%	6.5.20
16	Formaldehyde	705.165	542.427	-162.739	- 23.08%	6.5.22
17	Nitrogen Oxides (NO_X)	49,962.027	34,651.346	-15,310.681	- 30.65%	6.5.9

#	Pollutant	2017 Final	2021 Draft	Difference	% Change[a]	See Section
18	Ammonia (NH_3)	8.394	4.614	-3.779	- 45.03%	6.5.11
19	Carbon Monoxide (CO)	51,872.132	28,387.616	-23,484.516	- 45.27%	6.5.8
20	Methane (CH_4)	187,894.28	95,945.61	-91,948.67	- 48.94%	6.5.1.1
21	Ethyl Benzene	17.91	4.234	-13.676	- 76.36%	6.5.13
22	Benzene	225.433	49.893	-175.54	- 77.87%	6.5.13
23	Xylenes (Mixed Isomers)	101.58	17.623	-83.957	- 82.65%	6.5.13
24	Toluene	226.231	25.249	-200.982	- 88.84%	6.5.13
25	Chromium	-	0	-	-	-
26	Cyclohexane	-	0.3525	-	-	-
27	Cyclopentane	-	1.96	-	-	-
28	Ethane	-	138.377	-	-	-
29	Hydrogen Sulfide	-	0.3811	-	-	-
30	Isobutane	-	48.447	-	-	-
31	Isopentane	-	42.304	-	-	-
32	Methylcyclohexane	-	0.5991	-	-	-
33	N-Butane	-	124.111	-	-	-
34	N-Dodecane	-	3.968	-	-	-
35	N-Heptane	-	129.871	-	-	-
36	N-Nonane	-	0	-	-	-
37	N-Octane	-	0	-	-	-
38	N-Pentane	-	57.835	-	-	-
39	PAH, total	-	1.351	-	-	-
40	PAH/POM (Unspecified)	2.276	N/A	-	-	-
41	Particulate Matter Less Than 10 Microns (PM10)	N/A	420.622	-	-	-
42	Particulate Matter Less Than 2.5 Microns (PM25)	N/A	414.334	-	-	-
43	PM Condensible (PM-CON)	192.413	N/A	-	-	-
44	PM10 Filterable (PM10-FIL)	443.569	-	-	-	-
45	PM10 Primary (Filt + Cond) (PM10-PRI)	636.255	-	-	-	-
46	PM2.5 Filterable (PM25-FIL)	442.409	-	-	-	-
47	PM2.5 Primary (Filt + Cond) (PM25-PRI)	635.095	-	-	-	-
48	Propane	-	148.031	-	-	-
49	Total Hydrocarbons (THC)	-	38,866.129	-	-	-

Notes: [a] $Percentage\ Change = \frac{\text{2021 Draft Emissions} - \text{2017 Final Emissions}}{\text{2017 Final Emissions}} \times 100\%$

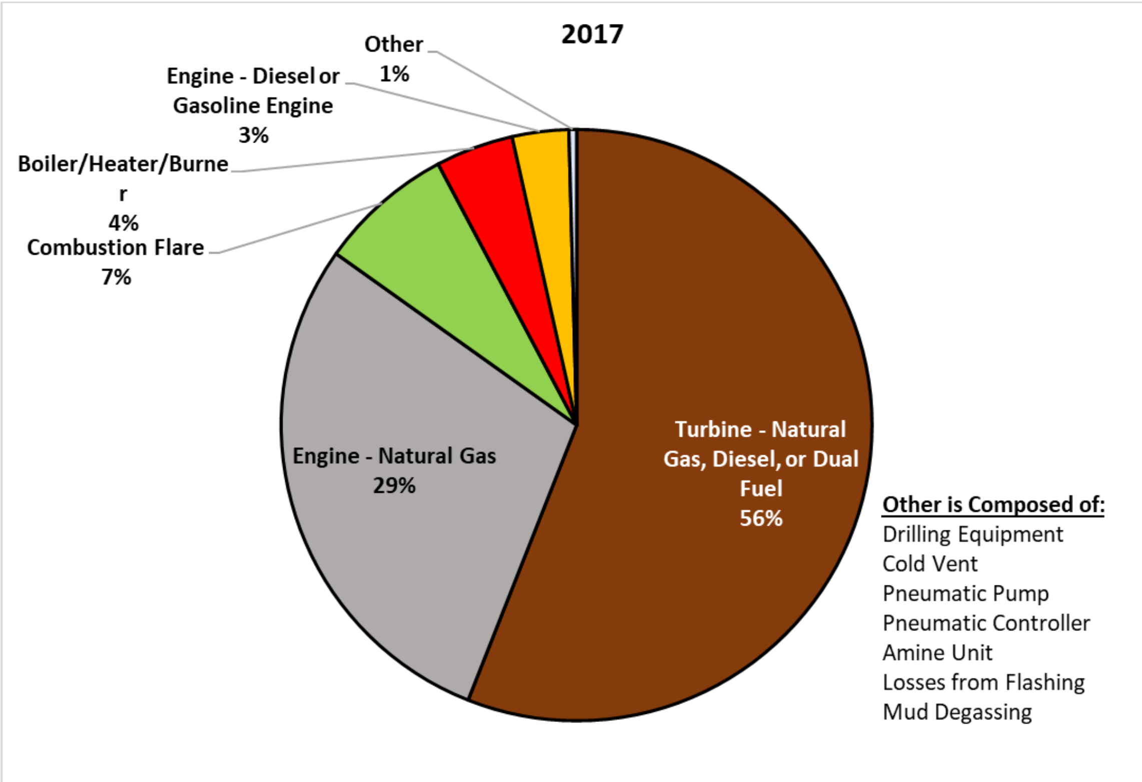
NOTE: The 2021 final emissions data (after the incorporating corrective actions) are compared to 2017 final emissions data and presented in Section 8.

6.5.1 Carbon Dioxide (CO_2)

Table 60 shows that 2021 draft annual emissions of CO_2 increased compared to 2017. In the 2021 draft inventory, operators reported 15,793,642.6 tons of CO_2 emissions, which is 130.32% higher than the reported emissions in 2017 of 6,857,359.61 tons.

6.5.1.1 CO_2 Emissions by Equipment Type

Using the Reports module in OCS AQS, CO_2 emissions for both the 2017 final and 2021 draft inventories were exported into Microsoft (MS) Excel and used to generate Figure 14. As illustrated, combustion flares are the highest contributors to the total CO_2 emissions in the 2021 draft inventory. The contribution of combustion flares in the 2021 draft inventory drastically increased, making "Turbine - Natural Gas, Diesel, or Dual Fuel" and "Engine - Natural Gas" lower compared to their contribution to the 2017 CO_2 emissions. Therefore, the following sections provide a deeper investigation of the combustion flares emission units in the 2021 draft and 2017 final inventories are conducted to identify data- or calculation-related issues.



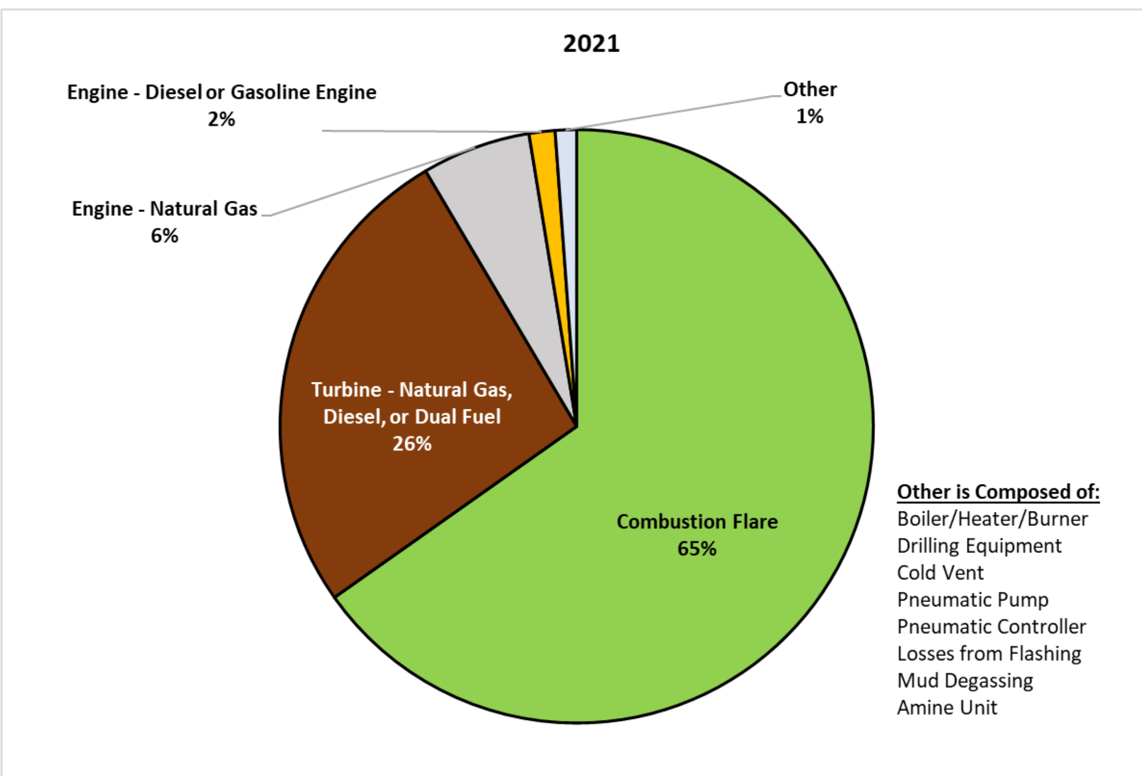


Figure 14: Percentage of CO_2 emissions by equipment type for 2017 final and 2021 draft data

6.5.1.2 Increase in CO_2 Emissions – Investigations

CO_2 emissions from combustion flares are calculated under flaring processes and pilot using the following equations (Wilson et al. 2019):

- Flaring processes: $E = V \times H \times EF \times 0.001$

  where V = Total volume of gas flared, not including pilot (Mscf), H = Flare gas heating value (Btu/scf), EF = Emission factor (lb/MMBtu)

The above equation indicates that the calculated CO_2 emissions from flaring processes are directly proportional to the volume of gas flared (not including pilot), flare gas heating value, and EF.

- Pilot processes: $E = P \times D \times EF \times 0.001$

  where E = Emissions (lb/month), P = Pilot feed rate (Mscf/day), D = Number of days in month (day), EF = Emission factor (lb/MMscf)

The above equation indicates that the calculated CO_2 emissions from pilot processes are directly proportional to the pilot feed rate and EF.

Therefore, the quality of data provided for the throughput to both processes (total volume of gas flared not including pilot and the pilot feed rate) will be further investigated in the following section.

> ***NOTE:*** A slight increase in CO_2 flares emissions was anticipated from 2017 final to 2021 draft data by a factor of 3.37 due to the different CO_2 EFs used for calculating the CO_2 flares emissions (Section 5.1.1). Nonetheless, this discrepancy in EFs is not high enough to cause that 130% increase in CO_2 annual emissions.

6.5.1.2.1 Investigations on Combustion Flares Throughputs (Total Volume of Gas Flared not Including Pilot and Pilot Feed Rate)

As previously mentioned, a considerable increase in the flares throughput (total volume of gas flared not including pilot and pilot feed rate) should lead to an increase in the flares' CO_2 emissions. Comparing the total annual volume of gas flared would only be valid if the overall count of the combustion flare emission units is also analyzed. Any change in the total count of combustion flare emission units should lead to a corresponding difference in the throughput (gas flared).

As shown in Table 61, the count of combustion flares reported in the 2021 Draft Emissions Inventory increased by 26.67%, but only 100 of 114 flares were actively emitting; the remaining combustion flare emission units belonged to non-operating facilities or were reported as Zero Emissions processes. As a result, the actual increase in the count of emitting combustion flares emission unit was 11.11%. Nevertheless, the corresponding increase in the total annual volume of flared gas because of the increase in the total count of emission units was highly questionable (2,607% increase). That percentage increase cannot be considered acceptable and requires further investigations.

Table 61: Comparison of combustion flares throughputs and equipment counts by inventory year (pre-corrective action)

Parameter	2017 Final	2021 Draft	% Change
Number of Combustion Flare Emissions Units Reported in the Inventory	90	114	+ 26.67%
Number of **Active Emitting** Flares Emission Units	90 of 90	100 of 114	+ 11.11%
Total Volume of Gas Flared (including both flaring and pilot) [Mscf]	6,264,700	169,615,121	**+ 2,607%**

The Flare Gas Volume by Facility report in OCS AQS provides detailed information on the amounts of gas flared by the flare emission units (flaring and pilot processes) for each month at each selected facility in the inventory. The Team generated the report for the 2021 draft inventory and analyzed the data to find any data entry issues in the throughputs causing this substantial increase in the combustion flares' CO_2 emissions. Based on review of combustion flare throughputs, the highest value of 163,349,231 Mscf of flared gas, representing 96.2% of the total flared gas by all the 100 emitting combustion flares was determined to belong to Facility ID# 23846-1 (Shell Pipeline Company LP). Table 62 provides a detailed breakdown of the volume of gas flared by Facility ID# 23846-1 in the 2021 draft inventory. It can be observed that the pilot process FL-NPP under INTER combustion flare emission unit is the process contributing the highest value of 163,153,375 Mscf of flared gas in the 2021 draft inventory.

Table 62: Annual volume of gas flared (Mscf/year) by Facility ID# 23846-1 (Shell Pipeline Company LP) in the 2021 draft inventory (pre-corrective action)

Emission Unit ID	Process ID	2021 Total Volume of Gas Flared (including both flaring and pilot)
INTER	FL-NPp	163,153,375
ROUTINE	FL-NPp	18,582
ROUTINE	FL-NPf	4,341
INTER	FL-NPf	172,933
-	**Total**	163,349,231

The Team contacted the operator of Facility ID# 23846-1 and requested further explanation on the questionably high pilot throughput. The operator confirmed that this high annual throughput was the result of data entry errors in the monthly throughputs provided in the 2021 inventory and requested setting the facility to corrective action to fix the monthly values and recalculate emissions. The Team set the facility to corrective action, and the operator fixed the monthly data. Table 63 shows the corrected values after the corrective action.

Table 63: Monthly volume of gas flared (Mscf/month) by process FL-NPp under INTER emission unit in Facility ID# 23846-1 in the 2021 draft inventory (pre- vs. post-corrective action)

Month	Pre-Corrective Action Process FL-NPp Monthly Throughput	Post-Corrective Action Process FL-NPp Monthly Throughput
January	15,097,775	1,519
February	13,636,700	1,372
March	15,097,775	1,519
April	14,610,750	1,470
May	15,097,775	1,519
June	14,610,750	1,470
July	15,097,775	1,519
August	15,097,775	1,519
September	-	-
October	15,097,775	1,519
November	14,610,750	1,470
December	15,097,775	1,519
Total [Mscf]	**163,153,375**	**16,415**

6.5.1.3 CO_2 Emissions – Findings

After analyzing the CO_2 emissions and investigating combustion flares' CO_2 emissions, the Team concluded that CO_2 emissions increased by approximately 131% in the 2021 draft inventory due to the 2,607% increase in the volume of gas flared. That increase in the throughput resulted from a data entry error that was corrected, as presented above in Table 63. The corrective action requested in this section and other corrections made throughout the document resulted in a 62% reduction in total annual CO_2 emissions. The estimated emissions in the 2021 draft amount were 15,793,642 tons/year, whereas the final amount, after corrective action was completed, was reduced to 5,935,334.81 tons/year (Section 8.1).

Table 64 compares the flared gas by inventory year after incorporating the corrective actions and shows that the annual volume of gas flared increased by 3.41% due to the 11% increase in the count emitting combustion flares. Those results are reasonable; therefore, no further investigations are conducted in this section.

Table 64: Flared gas (Mscf/year) by inventory year (post-corrective action)

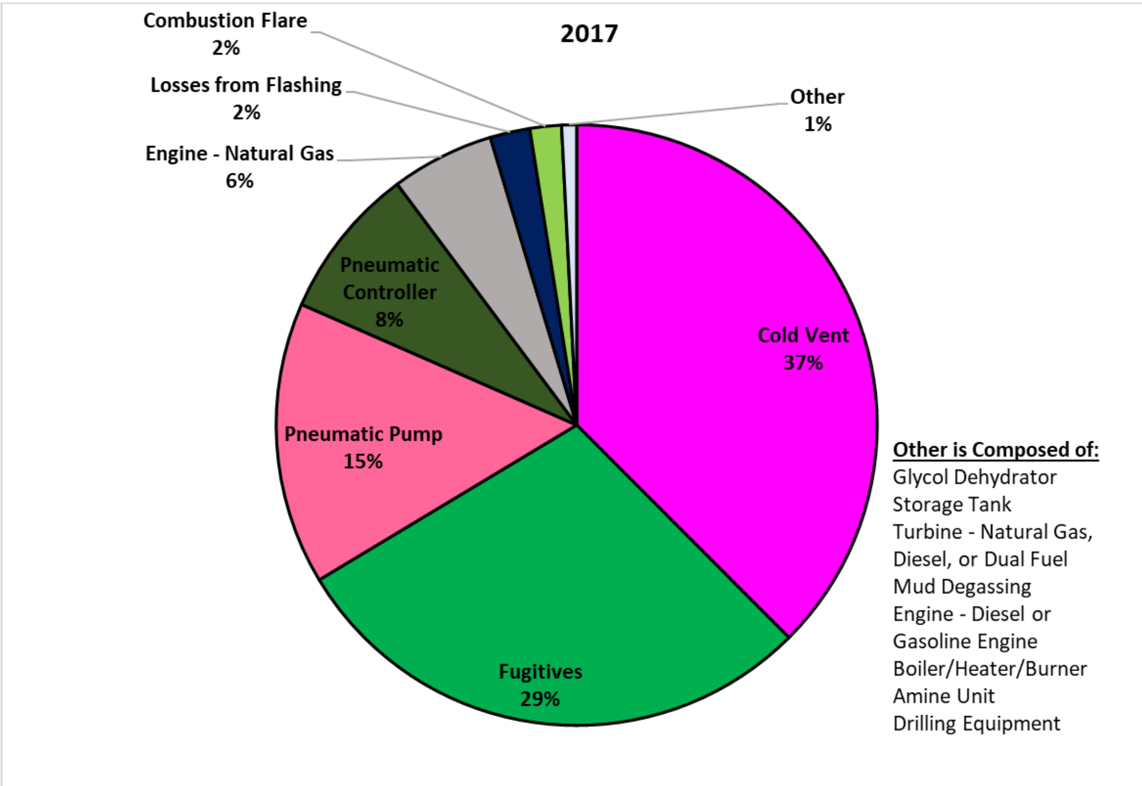
Parameter	2017 Final	2021 Draft, Post-Corrective Action	% Change
Number of Combustion Flare Emissions Units Reported in the Inventory	90	114	+ 26.67%
Number of **Active Emitting** Flares Emission Units	90 of 90	100 of 114	+ 11.11%
Total Volume of Gas Flared (including both flaring and pilot) [Mscf]	6,264,700	6,478,161	+ 3.41%

6.5.2 Methane (CH_4)

Table 60 shows that 2021 draft annual emissions of CH_4 decreased compared to 2017. In the 2021 draft inventory, operators reported 95,945 tons of CH_4 emissions, which is 48.94% lower than the reported CH_4 emissions in the 2017 final data of 187,895 tons.

6.5.2.1 CH_4 Emissions by Equipment Type

Using the Reports module in OCS AQS, CH_4 emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 15. As illustrated, cold vents are the highest contributors to the total CH_4 emissions in both inventory years. Therefore, the following sections provide a deeper investigation of the cold vent emission units in the 2021 draft and 2017 final inventories are conducted to identify data- or calculation-related issues.



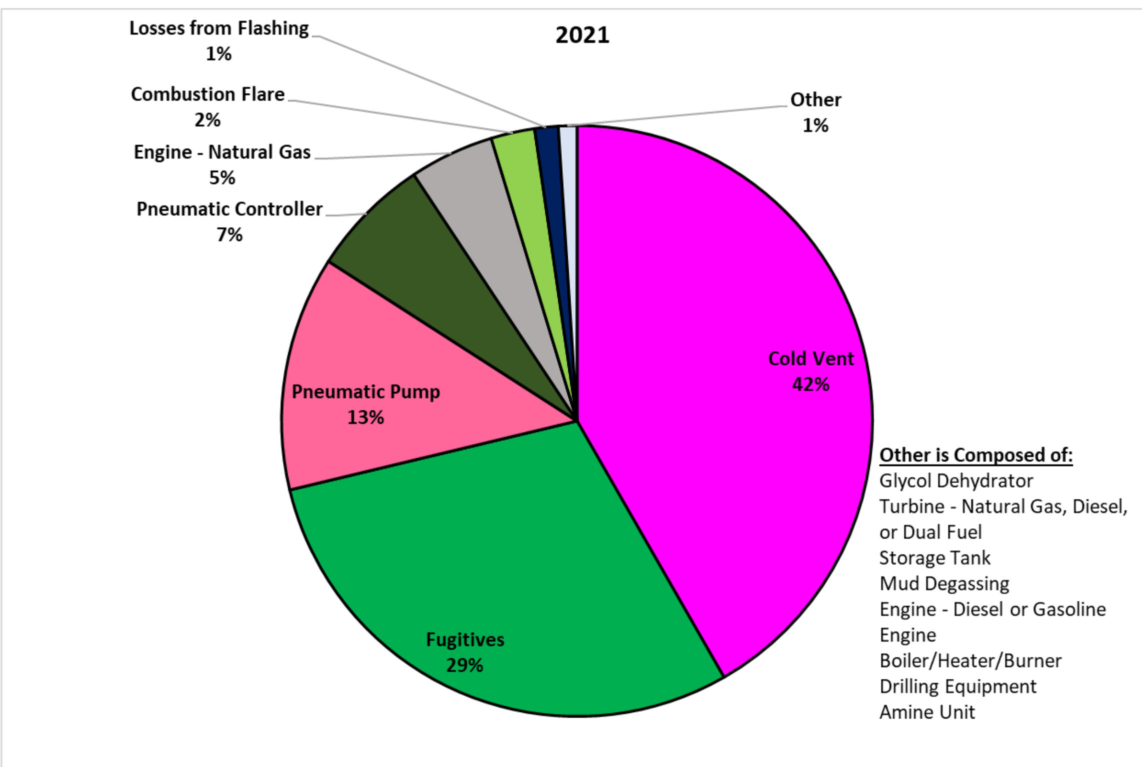


Figure 15: Percentage of CH_4 emissions by equipment type for 2017 final and 2021 draft data

6.5.2.2 Decrease in CH_4 Emissions – Investigations

CH_4 emissions from cold vents are calculated using the following equation (Wilson et al. 2019):

$$E_{CH_4} = WP_{CH_4} \times \frac{m_S}{379.4\,\frac{\text{scf}}{\text{lb.mol}}} \times 1000 \times V \qquad (Eq. 71)$$

The above equation indicates that the calculated CH_4 emissions from cold vents are directly proportional to the weight percent of CH_4 (WP_{CH_4}), the volume of gas vented from miscellaneous sources (V), and the sale gas mole weight. Both the weight percent of CH_4 and the sales gas mole weight depend on the compositions of the constitutes in the sales gas (provided by each facility); those compositions might differ from one platform to another.

Therefore, the quality of data provided for the volume of gas vented and facilities' sales gas compositions will be further investigated.

6.5.2.2.1 Investigations on Volume of Vented Gas

As analyzed, a decrease in the vent's throughput (volume of vented gas) should lead to a decrease the cold vent CH_4 emissions. Comparing the total annual vented gas volumes would only be valid if the overall count of the cold vent units is also analyzed. This is because any change in the total count of cold vents should lead to a corresponding difference in the throughput (vent gas).

As shown in Table 65, the count of cold vents reported in the 2021 effort increased by 23.33%, but only 372 of 666 cold vents were actively emitting; the remaining cold vents belonged to non-operating facilities or were reported as Zero Emissions processes. As a result of the 31.11% decrease in the count of emitting cold vent processes, the annual volume of vented gas decreased by 38.2%.

Table 65: Comparison of cold vent throughputs and equipment counts in the 2021 draft data

Parameter	2017 Final	2021 Draft	% Change
Number of Cold Vent Processes Reported in the Inventory	540	666	+ 23.33%
Number of **Active Emitting** Cold Vent Processes	540 of 540	372 of 666	- 31.11%
Volume of Vented Gas to Active Emitting Processes [Mscf]	3,691,354	2,282,582	- 38.16%

The decrease in vented gas due to the decrease of active emitting venting processes could explain the decrease in CH_4 emissions, but it would be more informative to conduct a more in-depth analysis on the sales gas data to investigate if any of the facilities failed to provide proper sales gas compositions (including CH_4). This analysis is discussed in the following subsection.

6.5.2.2.2 Investigations on Sales Gas Data

An in-depth analysis was previously conducted in Section 4.6.1 to study the provided sales gas data for all submitted inventories in the 2021 draft data. It was reported that 51 facilities did not provide sales gas compositions (see Table 44 for more information about those 51 facilities). However, the automated QA checks in OCS AQS prevent calculating cold vent emissions under facilities that do not have sales gas data and require the users to provide the missing sales gas data if they attempt to calculate cold vent emissions. This eliminates the possibility of a decrease in CH_4 emissions due to missing CH_4 compositions in sales gas. Therefore, it can be concluded that the missing sales gas data did not impact the CH_4 emissions values in the 2021 draft inventory and did not contribute to the decrease in CH_4 emissions.

6.5.2.3 Decrease in CH_4 Emissions – Findings

After analyzing the CH_4 emissions and investigating cold vent CH_4 emissions, it was concluded that CH_4 emissions decreased to nearly half the 2017 amount in 2021 due to the 38% reduction in the combined values specified for the Volume of Vented Gas parameter of the Cold Vent emission units.

6.5.2.4 Decrease in CH_4 Emissions – Recommendations

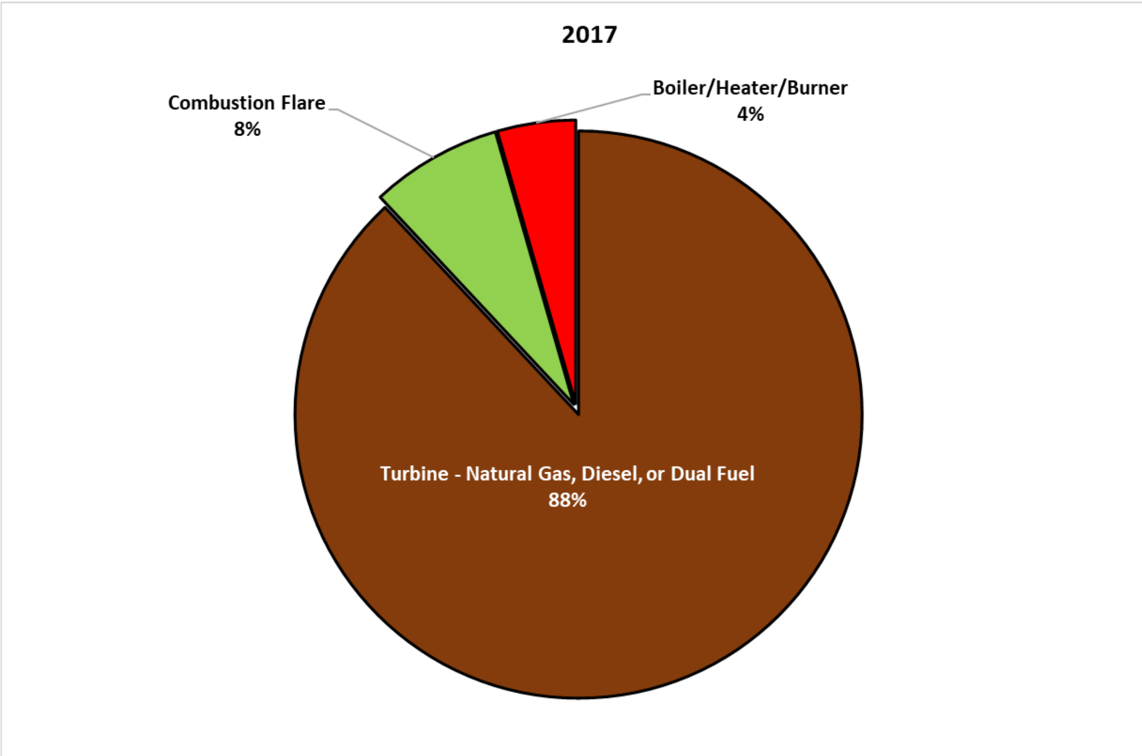
Our analysis confirmed that the decrease in CH_4 emissions does not result from poor data or incorrect calculation methods; it can be considered acceptable and compatible with the analyzed variables. Therefore, no further action is required. In future inventory efforts, operators will be able to analyze their activity data (in this case, volume of vented gas) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data to BOEM.

6.5.3 Nitrous Oxide (N_2O)

Table 60 shows a minimal increase in the total 2021 draft annual emissions of N_2O. In the 2021 draft inventory, operators reported 121.2 tons of N_2O emissions, which is 2.53% higher than the reported emissions in the 2017 final data of 118.21 tons.

6.5.3.1 N_2O Emissions by Equipment Type

Using the Reports module in OCS AQS, N_2O emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 16. As illustrated, the NGT are the highest contributors to the total nitrous oxide emissions in both inventory years. The emissions in both inventory years (2017 final and 2021 draft) were comparable, and no further analysis or corrective action was conducted on the 2021 draft activity data in this section.



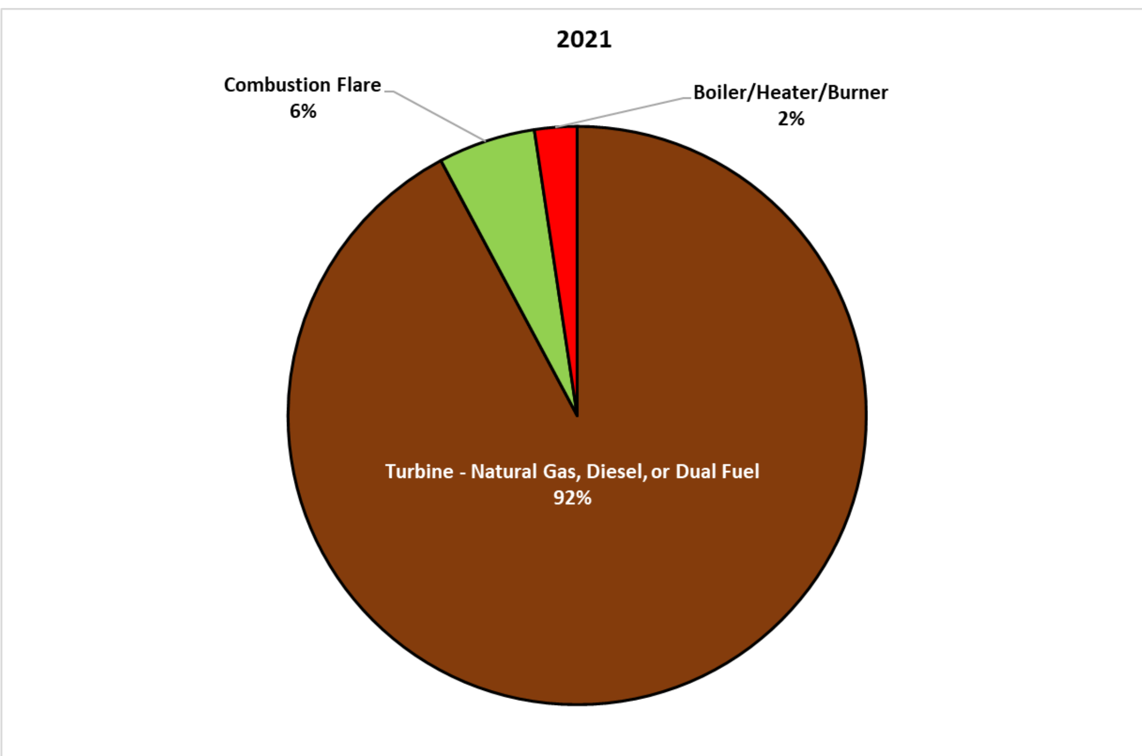


Figure 16: Percentage of N_2O emissions by equipment type for 2017 final and 2021 draft data

6.5.4 Carbon Dioxide Equivalent (CO_2-E)

CO_2-E values are obtained by multiplying the emissions of GHG pollutants by their GWP factors. In the 2017 final and 2021 draft inventory years, GWP factors were 1, 25, and 298 for CO_2, CH_4, and N_2O, respectively. Table 60 shows that 2021 draft annual emissions of CO_2-E increased in comparison to 2017 final emissions. In the 2021 draft inventory, 18,228,399.3 tons of CO_2-E were calculated based on the GHG annual emissions, which is 57.28% higher than the reported emissions in 2017 of 11,589,943.1 tons. All observed discrepancies in the emissions of the CO_2, CH_4, and N_2O contributed to the discrepancy in CO_2-E emission. Therefore, this percentage change is expected due to the excessive increase in the CO_2 emissions that was discussed earlier in Section 6.5.1.

The excessive 130% increase in the CO_2 emissions was addressed and fixed in Section 6.5.1, and the 2021 draft CO_2-E emissions were recalculated using the revised CO_2 emissions after incorporating the corrective action that was done in Section 6.5.1. Therefore, the new 2021 draft CO_2-E emissions became 8,316,052.40 tons. This is now 28.25% lower (-) than the reported emissions in 2017 (a total of 11,589,943 tons).

Therefore, in Section 6.5.4.1, the value of 8,316,052.40 tons of CO_2-E emissions was used as the 2021 draft emissions value (this value takes into account the corrective action done in Section 6.5.1).

6.5.4.1 CO_2-E by Equipment Type

Using the Analytics module in OCS AQS, GHG annual emissions by equipment type stacked column charts were generated for both the 2017 final and 2021 draft inventories. Exported charts are presented in Figure 17 and Figure 18. As illustrated in both figures, turbines (NGT) and engines (NGE) are the two highest GHG emitting sources. Both sources (turbines and engines) are combustion pieces of equipment, and most of their CO_2-E emissions are acquired from the CO_2 emissions.

From analysis, GHG emissions from cold vents and fugitive sources primarily result from CH_4 emissions because vents and fugitives do not encounter any combustion processes when releasing emissions into the atmosphere. In general, when compared to the 2017 final emissions, emitted GHG (mostly CH_4) from both cold vents and fugitive units decreased in 2021. Conversely, in 2021, overall CO_2-E emission from pneumatic pumps (PNE) increased because of the increase in the PNE CH_4 emissions; this increase made the PNE contribution to CO_2-E more than the combustion flares' contribution (unlike 2017, where PNE contributed less than the flares).

In both reporting years (2021 draft and 2017 final), the slight N_2O contribution to the GHG emissions is driven by Turbine - Natural Gas, Diesel, or Dual Fuel (NGT). The decrease in CO_2-E emissions is mainly due to the decrease in CH_4 emissions that was discussed earlier in Section 6.5.2.2, and no further analysis and corrective actions was conducted on the 2021 draft activity data in this section.

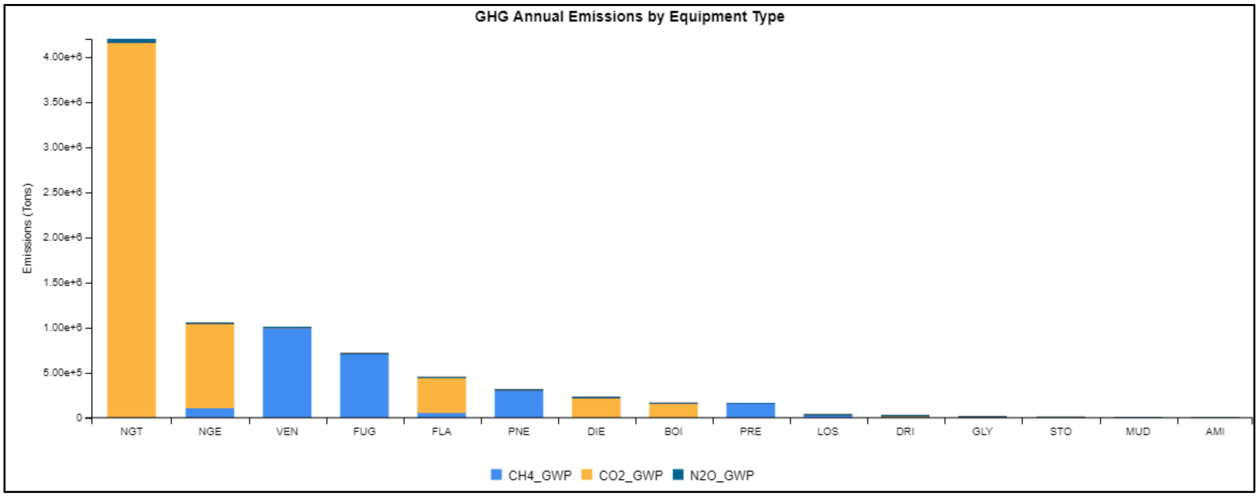


Figure 17: 2021 draft GHG emissions (tons/year) by equipment type

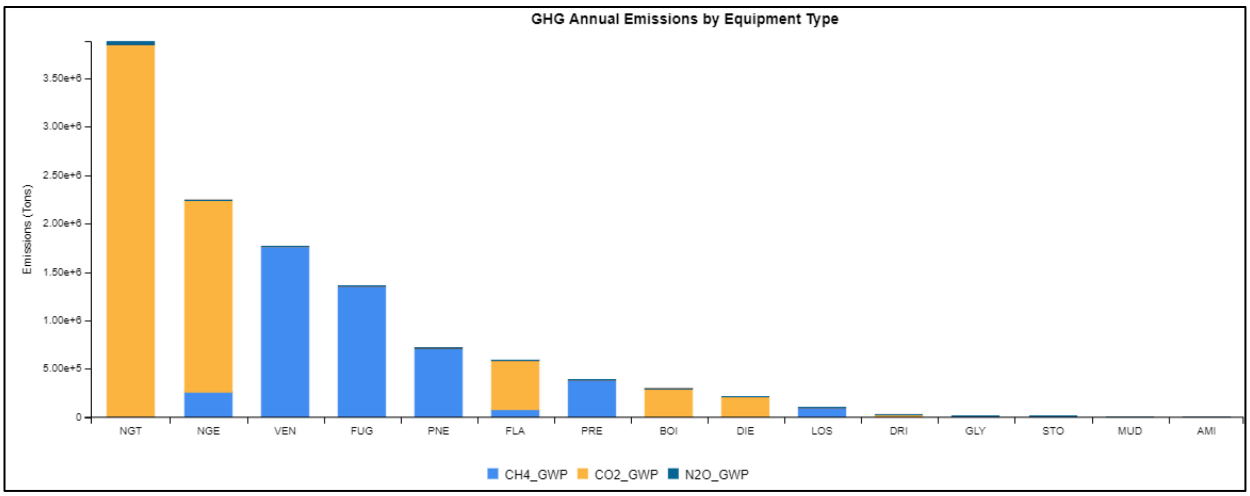


Figure 18: 2017 final GHG emissions (tons/year) by equipment type

6.5.5 Sulfur Dioxide (SO_2)

Table 60 shows an excessive increase in the total 2021 draft annual emissions of SO_2. In the 2021 draft inventory, operators reported 1,534 tons of SO_2 emissions, which is 232% higher than the reported emissions in the 2017 final data of 462 tons. In the following subsection, investigations are conducted to identify the fundamental reason for this excessive increase in the 2021 draft SO_2 emissions.

6.5.5.1 Sulfur Dioxide Emissions by Equipment Type

Using the Reports module in OCS AQS, SO_2 emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 19. As illustrated, the Turbine - Natural Gas, Diesel, or Dual Fuel (NGT) are the highest contributors to the total sulfur dioxide emissions in the 2021 draft inventory year. Therefore, the following sections provide a deeper investigation of the turbine emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.

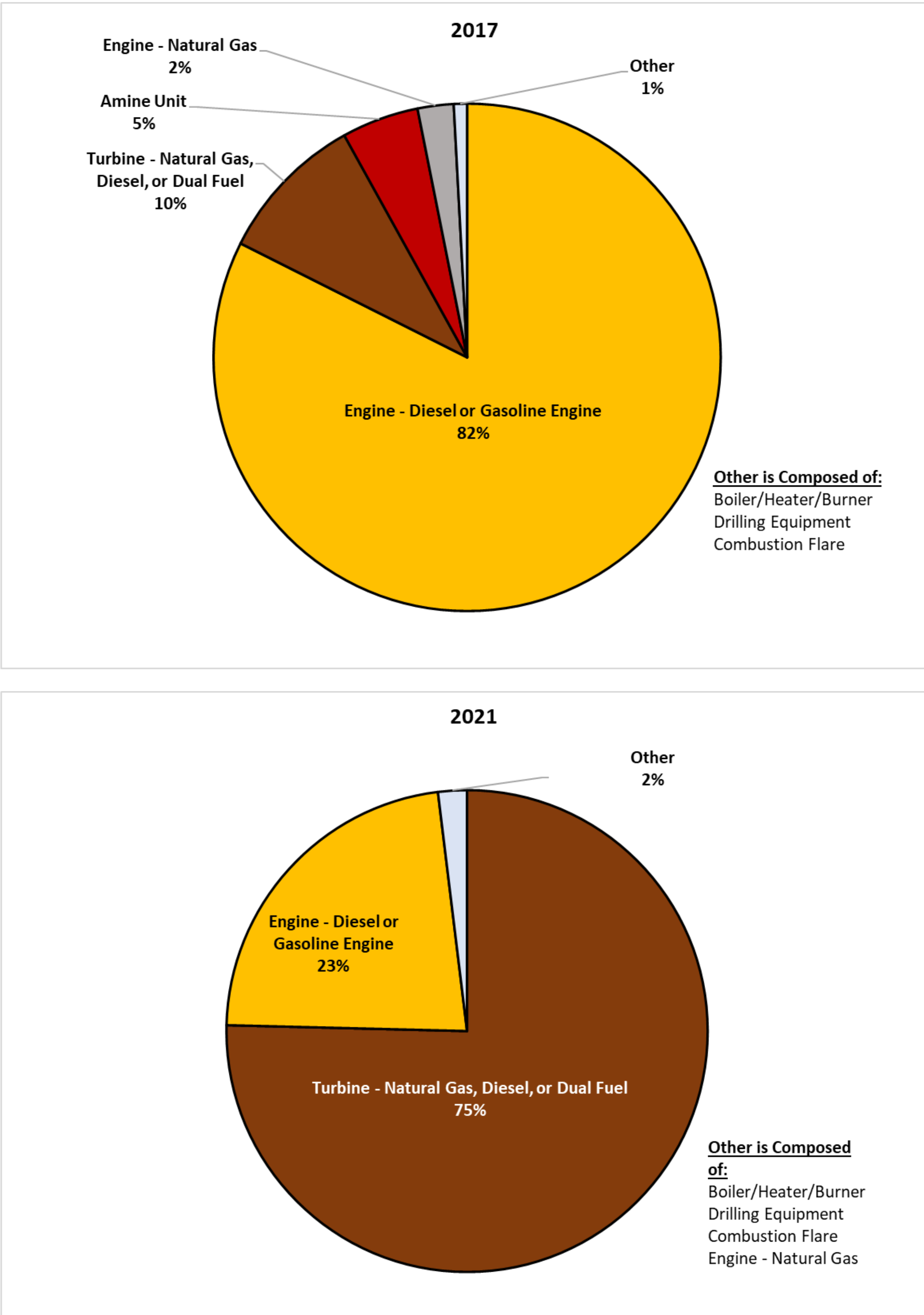


Figure 19: Percentage of sulfur dioxide emissions by equipment type for 2017 final and 2021 draft data

6.5.5.2 Increase in Sulfur Dioxide Emissions – Investigations

SO_2 emissions from NGT are calculated using the following equation (Wilson et al. 2019):

$$E = EF \times H \times U \times 0.001 \qquad (Eq.72)$$

The above equation indicates that turbines' SO_2 emissions are directly proportional to EF and Fuel Usage (U).

This makes turbine throughput (i.e., fuel usage) and SO_2 EF possible causes for the increase in SO_2 emissions. Therefore, the quality of data provided for the turbine units will be further examined.

> ***NOTE:*** The Fuel Heat Value (H) also has a direct impact on emissions; however, this property is intensive[5] and depends on the fuel type, therefore cannot be investigated.

6.5.5.2.1 Investigations of Turbine Throughputs

As seen in Eq.72 above, an increase in the turbine's throughput would lead to an increase in the SO_2 emissions. To compare the total annual throughput of turbines, their overall emission unit count needs to be considered.

The count of NGT processes reported in the 2021 effort increased by 14%, but only 336 of 396 NGT processes were actively emitting (the remaining NGT processes belonged to non-operating facilities or were reported as zero emissions processes) (Table 66). Even though there was a 4% decrease in the count of emitting NGT processes, annual volume of fuel usage by the NGT processes increased by 2.88%. Actively emitting diesel turbine (NGT-D) processes increased by 56.14% and resulted in a 44.68% increase in the total volume of diesel fuel usage by the diesel turbines (Table 66).

Table 66: Comparison of turbines throughputs and equipment counts in the 2017 final and 2021 draft data

Parameter	2017 Final	2021 Draft	% Change
Number of NGT Processes Reported in the Inventory	350	399	+ 14.00%
Number of **Active Emitting** NGT Processes	350 of 350	336 of 399	- 4.00%
Total Fuel Usage by Active Emitting Processes [Mscf]	58,631,713.19	60,321,144.52	+ 2.88%
Number of NGT-D Processes Reported in the Inventory	57	111	+ 94.74%
Number of **Active Emitting** NGT-D Processes	57 of 57	89 of 111	+ 56.14%
Total Fuel Usage by Active Emitting NGT-D Processes [Gallons]	3,468,139.36	5,017,722.15	+ 44.68%

Although the increase in the total fuel usage by the two types of turbines (NGT and NGT-D) can contribute to the increase in the SO_2 emissions, it is not enough to explain the excessive 232.12% increase of SO_2 emissions shown in the 2021 draft inventory; other factors are suspected to be highly contributing to that substantial increase. In the following sections, suspected factors are analyzed and investigated.

6.5.5.2.2 Investigations of the Calculated SO_2 EF For NGT

The SO_2 EF is calculated based on the fuel sulfur content. The SO_2 EF for NGT in the *Year 2017 Emissions Inventory Study* was calculated using the following equation (Wilson et al. 2019):

[5] An intensive property is a property of matter that its magnitude is independent of the extent of the system (Scheider and Huisjes 2019).

$$EF_{SO_2} = 0.94 \times S \qquad (Eq. 73)$$

where S is the fuel sulfur content (wt%)

As described in Eq.73, SO_2 EF depends on a constant value of (0.94) and the fuel sulfur content. Therefore, any changes to the constant multiplier (0.94) and/or the fuel sulfur content can be viewed as possible causes of the change in SO_2 EF and thus the SO_2 emissions.

6.5.5.2.3 Investigation of the SO_2 EF Multiplier Value

To identify any changes in the value of the multiplier (0.94), SO_2 emissions from January 2017 were recalculated with the January 2017 provided inputs (throughputs, heat values, and sulfur contents). If a similar multiplier was used in 2017, then the following ratio should be valid:

$$\frac{\text{2017 Historic Emissions}}{\text{Recalculated 2017 Emissions}} = 1$$

However, this was not the case. The historic emissions were significantly lower than the recalculated ones and the ratio between them was as follows:

$$\frac{\text{2017 Historic Emissions}}{\text{Recalculated 2017 Emissions}} = 0.000178$$

This ratio value was consistent for all 350 processes. This indicates that the EF formulation used in 2017 was as follows:

$$2017\ EF_{SO_2} = 0.000178 \times 2021\ EF_{SO_2} = 0.000178 \times 0.94 \times S$$

This calculation supports our Team's hypothesis regarding the change of the EF but does not explain the change in the multiplier because the formulations of emissions calculations used in both inventory years (2021 and 2017) were obtained from the *Year 2017 Emission Inventory Study* document (Wilson et al. 2019). However, the 0.000178 value warranted a deeper analysis of this multiplier to understand why it was used and how it was calculated.

Using the definition of sulfur percentage weight content, ideal gas equation, and the mass to molar basis conversion basics, the following was established:

As previously shown, the SO_2 EF for NGT(s) in the *Year 2017 Emissions Inventory Study* was calculated using the following equation (Wilson et al. 2019):

$$EF_{SO_2} = 0.94 \times S \qquad (Eq. 73)$$

where S is the Fuel sulfur content (wt%)

From the definition of mass percentage:

$$Fuel\ sulfur\ content\ (wt\%) = \frac{Mass\ of\ H_2S}{Total\ Mass\ of\ Fuel} \times 100 \qquad (Eq. 74)$$

$$Mass = Moles \times MW \qquad (Eq. 75)$$

Substituting $(Eq. 75)$ in $(Eq. 74)$,

$$Fuel\ sulfur\ content\ (wt\%) = \frac{Moles\ of\ H_2S\ \times\ MW_{H_SS}}{Moles\ of\ Fuel\ \times\ MW_{Fuel}} \times 100 \qquad (Eq. 76)$$

Form the definition of parts per million volumes:

$$PPM_v = \frac{Volume\ of\ H_2S}{Volume\ of\ Fuel} \times 10^6 \qquad (Eq. 77)$$

For ideal gas (only):

$$\frac{Volume\ of\ H_2S}{Volume\ of\ Fuel} = \frac{Moles\ of\ H_2S}{Moles\ of\ Fuel} \qquad (Eq. 78)$$

Substituting $(Eq. 78)$ and $(Eq. 77)$ in $(Eq. 76)$,

$$Fuel\ sulfur\ content\ (wt\%) = \frac{PPM_v \times\ MW_{H_2S}}{10^6\ \times\ MW_{Fuel}} \times 100 \qquad (Eq. 79)$$

If the fuel is natural gas (NG) then,

$$MW_{Fuel} = MW_{NG} = 19.14382 \frac{g}{mol}$$

This value is the industrial average and could differ for different natural gas compositions.

$$MW_{H_SS} = 34.1 \frac{g}{mol}$$

Substituting the molecular weights in $(Eq. 79)$,

$$Fuel\ sulfur\ content\ (wt\%) = \frac{PPM_v \times\ 34.1}{10^6\ \times 19.14382} \times 100 = PPM_v\ \times 0.000178 \qquad (Eq. 80)$$

The above equation (*Eq.* 80) confirms that the EF_{SO_2} in 2017 is consistent with the one used in 2021 **EXCEPT** that the sulfur content in 2017 was provided in PPM_v, **NOT** wt%, and that the 0.000178 value is the conversion factor used to convert from PPM_v to wt%. This conclusion shows that there is no change in the SO_2 EF formulation. Therefore, analysis of the submitted sulfur content data is required to identify any anomalous trends or/and data entry errors.

6.5.5.2.4 Investigations of Fuel Sulfur Content

An increase in natural gas fuel sulfur content leads to an increase in EF_{SO_2}, as already documented, which would increase SO_2 emissions.

In OCS AQS, sulfur values are user-defined and are requested in wt%. It is possible that OCS AQS operators and consultants provided the sulfur content values in PPM_v, as they were requested in 2017 efforts (as shown in the previous section). To support this hypothesis, a comparison between the 2021 data and 2017 historic data was conducted to identify any increase or changes in the fuel sulfur content.

Figure 20 compares the NGT sulfur content data as entered by operators in 2021 and 2017. The maximum provided value for fuel sulfur content was 0.000712 in 2017; however, 953 entries (see the count of entries highlighted by the red box in Figure 20) have a value greater than that in 2021. Therefore, those

953 entries, belonging to different facilities for different emissions units, could substantially increase the SO_2 EFs and would, ultimately, increase the overall SO_2 emissions from turbines.

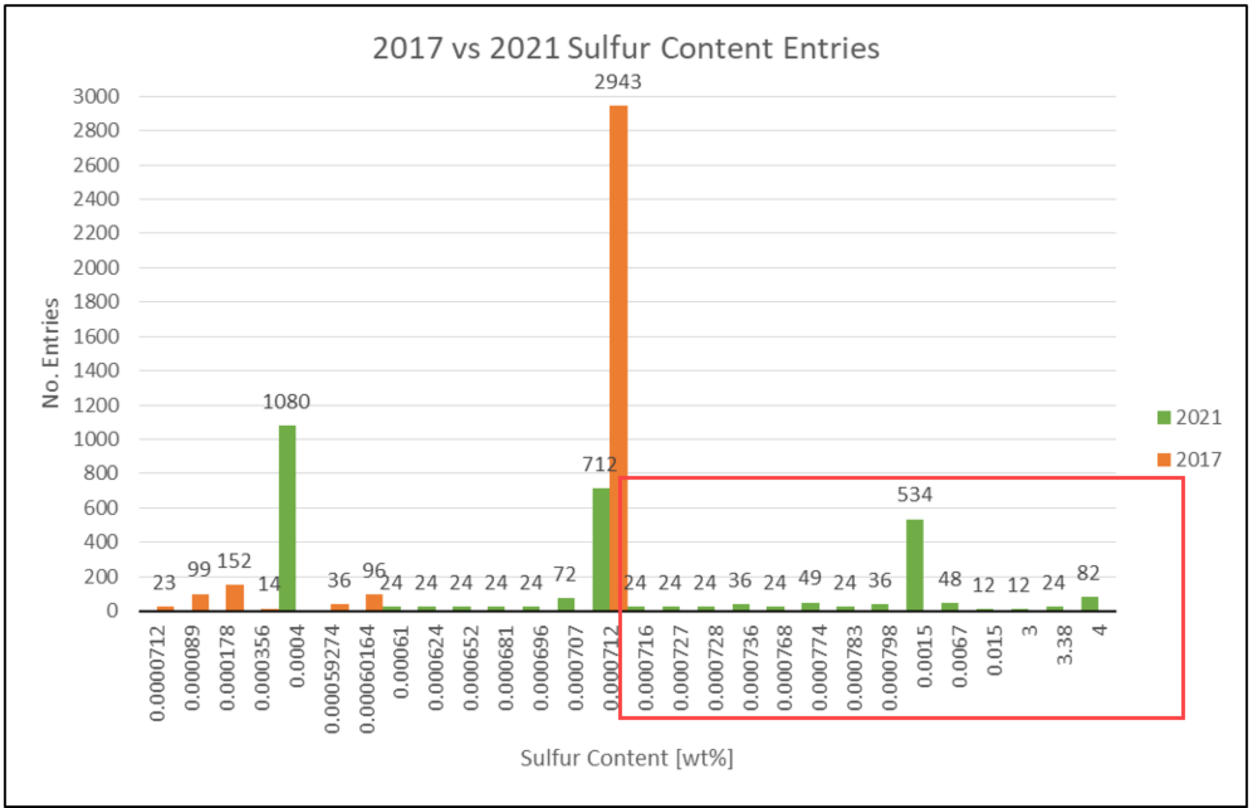


Figure 20: Count of NGT sulfur content (wt%) entries for 2017 final (orange columns) and 2021 draft (green columns) data

The red box in Figure 20 highlights the count of 2021 draft NGT sulfur content (wt%) entries with high values (ranging from 0.000716% to 4%).

> ***NOTE:*** The 2017 sulfur content entries are in PPM_v, and before preparing Figure 20, all PPM_v values were converted to wt% with an assumption of 19.14382 g/mol natural gas molecular weight. See Figure 21 for the 2017 raw sulfur content data in PPM_v.

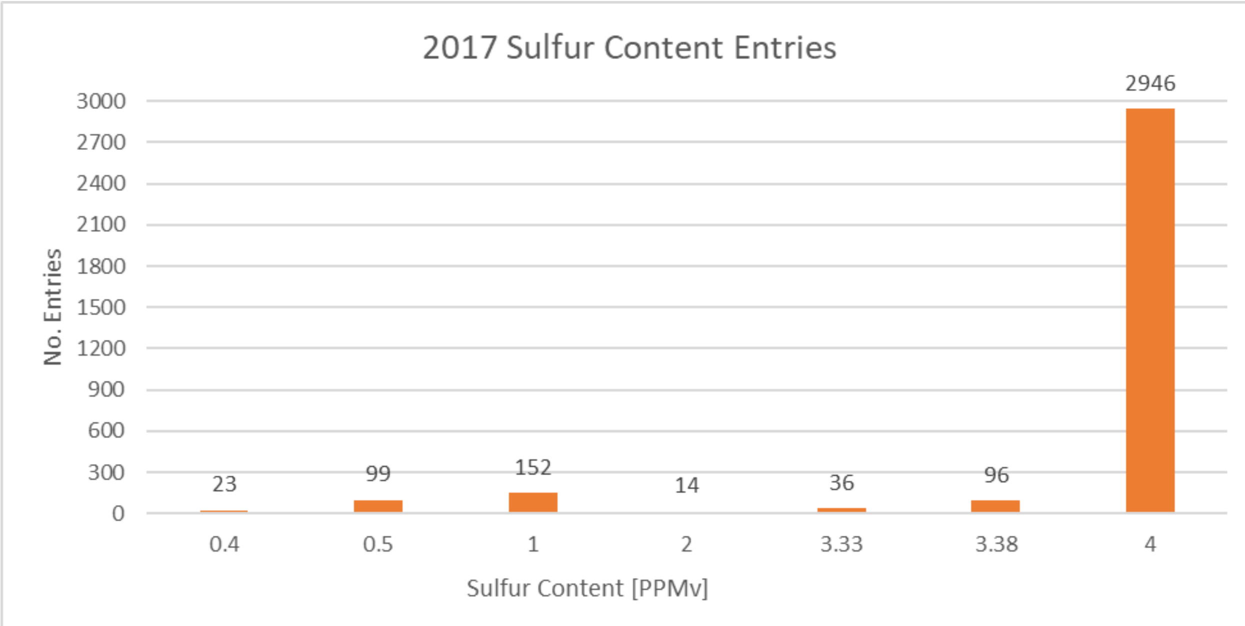


Figure 21: Count of 2017 final NGT sulfur content (ppm) entries

Based on the observations above, it can be concluded that although the formulation of the SO_2 EF did not change, the final calculated values are substantially higher. This increase considerably impacted turbines' SO_2 calculated emissions and caused the spike seen in 2021.

6.5.5.3 Increase in Sulfur Dioxide Emissions – Investigations Findings

By analyzing the entries shown in Figure 20, the wt% 0.0004 has the highest number of entries in the 2021 draft data, while the wt% 0.000712 has the highest count in the 2017 final data. The value 0.000712 is equivalent to 4 PPM_v. This indicates that in the 2021 draft data, 1,080 entries were incorrectly converted from PPM_v to wt% by the following formula: PPM_v/10,000. This direct division by 10,000 does not consider the molecular weights of the gases (H_2S and natural gas) and converts the data to mol% (assuming ideal gas) NOT to wt%. In fact, 0.000712 wt% has the second highest number of entries in the 2021 draft data, which means that 712 entries were properly converted from wt% to PPM_v in the 2021 draft data.

In Table 3-2 of the *Year 2017 Emissions Inventory Study*, the fuel hydrogen sulfide (H_2S) content should be within the range of 0–5 PPM_v (equivalent to 0–0.00089 wt%, assuming $MW_{NG} = 19.14382 \frac{g}{mol}$) (Wilson et al. 2019). Therefore, values that are substantially greater than 0.00089 are considered high and required corrections to properly convert the units from PPM_v to wt%.

For instance, in Figure 20, there are 534 entries with a value of 0.0015 wt% (equivalent to 8.4269663 PPM_v, assuming $MW_{NG} = 19.14382 \frac{g}{mol}$). This value is beyond the accepted range for fuel hydrogen sulfide (H_2S) content and leads to a considerable increase in SO_2 emissions. In fact, this value was commonly used by the operators because it was provided as the surrogate diesel sulfur content value; see Table 4-1 in Wilson et al. (2019). Consequently, operators mistakenly used the value of 0.0015 wt% for natural gas fuels. Other high values in the 2021 draft data such as (3, 3.38, and 4) are for operators who failed to notice the change in the unit and provided the PPM_v values directly without converting them to wt%.

6.5.5.4 Increase in Sulfur Dioxide Emissions – Corrective Actions

After analyzing the sulfur content inputs for all turbine processes in both the 2017 final and 2021 draft inventories, the following corrective actions were requested to resolve the sulfur content data entry issue and recalculate turbines' SO_2 emissions in the 2021 draft inventory:

- For processes listed in Table 67, operators were requested to review provided sulfur content values for NGT and make sure that they are in wt%, not PPM_v, for all months (<u>including zeroed-out months</u>). The column "Post-Corrective Action Fuel Sulfur Content [wt%]" in Table 67 shows the corrected values.

  ***NOTE*:** For the purposes of data-keeping and to avoid similar issues in future reporting cycles, the Team recommend correctly converting the sulfur content values for all processes and months even if they are zeroed out and do not affect the final calculated emissions.

- For processes listed in Table 68, operators were requested to review the entered NGT sulfur content inputs; although they are converted, they are very high and not consistent with the values in the 2017 final data. The Column "Post-Corrective Action Fuel Sulfur Content [wt%]" in Table 68 shows the corrected values. The fuel sulfur content values under the four NGT processes belonging to Facility #2623-1 were not corrected; the operator confirmed the accuracy of the slightly high sulfur content values, justifying this by stating that the facility produces slightly sour gas.

- For processes listed in Table 69, operators were requested to review the provided wt% sulfur content values for the NGT processes and use the appropriate conversion method from PPM_v to wt%, considering the molecular weights. Here the operators directly divided the PPM_v value by 10,000 (to convert PPM_v to mol%, not wt%). The Column "Post-Corrective Action Fuel Sulfur Content [wt%]" in Table 69 shows the corrected values.

- For processes listed in Table 70, operators were advised to review the wt% sulfur content values for NGT, as they used the default diesel sulfur content value (0.0015) provided in the 2017 document. This value is considered high for natural gas, (equivalent to 8.4269663, assuming $MW_{NG} = 19.14382 \frac{g}{mol}$). The Column "Post-Corrective Action Fuel Sulfur Content [wt%]" in Table 70 shows the corrected values.

  NOTE: The default value for sulfur content in natural gas fuel is given in the 2017 document as 3.38 PPM_v (equivalent to 0.00060164 wt%, assuming $MW_{NG} = 19.14382 \frac{g}{mol}$).

- For Table 71, operators were advised to review the diesel sulfur content wt%, as they are not consistent with the values provided in the 2017 final inventory. The Column "Post-Corrective Action Fuel Sulfur Content [wt%]" in Table 71 shows the corrected values.

The corrective actions requested in this section and other corrections made throughout the document resulted in an 80% reduction in total annual SO_2 emissions. The estimated emissions in the 2021 draft amount were 1,534.591 tons/year, and the final amount was reduced to 299.419 tons/year (Section 8.1).

Table 67: Summary of emission units with sulfur content values not converted to wt% in the 2021 draft data

#	Company Name	Facility ID	2021 Emission Unit ID	Process ID	Pre- Corrective Action Fuel Sulfur Content [wt%]	Post- Corrective Action Fuel Sulfur Content [wt%]
1	Cantium, LLC	20390-3	COMPRESS	NGT	3	0.0015
2	Cox Operating LLC	21809-1	CT-01	NGT	4	0.000712
3	Cox Operating LLC	21809-1	CT-02	NGT	4	0.000712
4	Cox Operating LLC	21809-1	CT-03	NGT	4	0.000712
5	Cox Operating LLC	21809-1	CT-04	NGT	4	0.000712
6	Cox Operating LLC	21809-1	CT-05	NGT	4	0.000712
7	Cox Operating LLC	21809-4	GE-01	NGT	4	See note below
8	Cox Operating LLC	22564-1	GT-01-A	NGT	4	0.000712
9	Cox Operating LLC	22564-1	GT-02-B	NGT	4	0.000712
10	GOM Shelf LLC	21270-2	COMP	NGT	4	0.000774
11	High Point Gas Gathering, L.L.C.	24201-1	NGT001	NGT	3.38	0.00055
12	High Point Gas Gathering, L.L.C.	24201-1	NGT002	NGT	3.38	0.00055
13	Sea Robin Pipeline Company, LLC	70026-2	COM-NG-1	NGT	4	See note below

NOTE: Only Cox Operating LLC and Sea Robin Pipeline Company, LLC corrected the erroneous sulfur content values for operating emission units (i.e., non-zero emissions). However, these companies did not correct the erroneous values for emission units that were under zeroed-out months; these instances did not impact calculated emissions.

Table 68: Summary emissions units with high sulfur content wt% in the 2021 draft data

#	Company Name	Facility ID	2021 Emission Unit ID	Process ID	Pre- Corrective Action Fuel Sulfur Content [wt%]	Post- Corrective Action Fuel Sulfur Content [wt%]
1	Shell Offshore Inc.	2623-1	Turbine 1	NGT	0.0067	0.0067
2	Shell Offshore Inc.	2623-1	Turbine 2NG	NGT	0.0067	0.0067
3	Shell Offshore Inc.	2623-1	Turbine 3	NGT	0.0067	0.0067
4	Shell Offshore Inc.	2623-1	Turbine 4NG	NGT	0.0067	0.0067
5	Eni US Operating Co. Inc.	1175-1	CT-01	NGT	0.015	0.0015

Table 69: Summary of emission units with incorrect sulfur conversion (i.e., PPM_V divided by 10,000) in the 2021 draft data

#	Company Name	Facility ID	2021 Emission Unit ID	Process ID	Pre- Corrective Action Fuel Sulfur Content [wt%]	Post- Corrective Action Fuel Sulfur Content [wt%]
1	Anadarko Petroleum Corporation	235-1	CT-03	NGT	0.0004	0.000712
2	Anadarko Petroleum Corporation	822-1	GT-01	NGT	0.0004	0.000712
3	Anadarko Petroleum Corporation	822-1	GT-02	NGT	0.0004	0.000712
4	Anadarko Petroleum Corporation	876-1	GT-01A	NGT	0.0004	0.000712
5	Anadarko Petroleum Corporation	876-1	GT-02A	NGT	0.0004	0.000712
6	Anadarko Petroleum Corporation	876-1	GT-03A	NGT	0.0004	0.000712
7	ANKOR Energy LLC	361-1	GT-01	NGT	0.0004	0.000712
8	ANKOR Energy LLC	361-1	GT-02	NGT	0.0004	0.000712
9	Chevron USA Inc.	1819-1	EZZ5010	NGT	0.0004	0.0007
10	Chevron USA Inc.	1819-1	EZZ5110	NGT	0.0004	0.0007
11	Chevron USA Inc.	1819-1	EZZ5210	NGT	0.0004	0.0007
12	Chevron USA Inc.	1819-1	EZZ6705	NGT	0.0004	0.0007
13	Chevron USA Inc.	1819-1	EZZ6745	NGT	0.0004	0.0007
14	Chevron USA Inc.	1930-1	GT-01	NGT	0.0004	0.0007
15	Chevron USA Inc.	1930-1	GT-02	NGT	0.0004	0.0007
16	Chevron USA Inc.	2422-1	NGT001	NGT	0.0004	0.0007
17	Chevron USA Inc.	2422-1	NGT002	NGT	0.0004	0.0007
18	Chevron USA Inc.	2422-1	NGT003	NGT	0.0004	0.0007
19	Chevron USA Inc.	2440-1	TG-01	NGT	0.0004	0.0007
20	Chevron USA Inc.	2440-1	TG-02	NGT	0.0004	0.0007
21	Chevron USA Inc.	2440-1	TG-03	NGT	0.0004	0.0007
22	Chevron USA Inc.	70012-1	CT-01	NGT	0.0004	0.0007
23	Chevron USA Inc.	70012-1	CT-02	NGT	0.0004	0.0007
24	Chevron USA Inc.	70012-1	CT-03	NGT	0.0004	0.0007
25	Chevron USA Inc.	70012-1	GT-01	NGT	0.0004	0.0007
26	Chevron USA Inc.	70012-1	GT-02	NGT	0.0004	0.0007
27	Chevron USA Inc.	70012-1	GT-03	NGT	0.0004	0.0007
28	Chevron USA Inc.	70012-1	GT-04	NGT	0.0004	0.0007

#	Company Name	Facility ID	2021 Emission Unit ID	Process ID	Pre- Corrective Action Fuel Sulfur Content [wt%]	Post- Corrective Action Fuel Sulfur Content [wt%]
29	Contango Operators, Inc.	2103-3	NGT	NGT	0.0004	0.000712
30	Exxon Mobil Corporation	183-1	NGT001	NGT	0.0004	0.000712
31	Exxon Mobil Corporation	183-1	NGT002	NGT	0.0004	0.000712
32	Exxon Mobil Corporation	183-1	NGT003	NGT	0.0004	0.000712
33	Exxon Mobil Corporation	183-1	NGT004	NGT	0.0004	0.000712
34	Exxon Mobil Corporation	183-1	NGT005	NGT	0.0004	0.000712
35	Exxon Mobil Corporation	183-1	NGT006	NGT	0.0004	0.000712
36	Exxon Mobil Corporation	183-1	NGT007	NGT	0.0004	0.000712
37	Exxon Mobil Corporation	183-1	NGT008	NGT	0.0004	0.000712
38	Exxon Mobil Corporation	183-1	NGT009	NGT	0.0004	0.000712
39	Manta Ray Gathering Company, LLC	23212-2	OSP-01	NGT	0.0004	0.000712
40	Manta Ray Gathering Company, LLC	23212-2	OSP-02	NGT	0.0004	0.000712
41	Manta Ray Gathering Company, LLC	23212-2	OSP-03	NGT	0.0004	0.000712
42	Manta Ray Gathering Company, LLC	23212-2	OSP-04	NGT	0.0004	0.000712
43	Manta Ray Gathering Company, LLC	23353-1	OIL-P-01	NGT	0.0004	0.000712
44	Manta Ray Gathering Company, LLC	23353-1	OIL-P02	NGT	0.0004	0.000712
45	Manta Ray Gathering Company, LLC	23353-1	OIL-P03	NGT	0.0004	0.000712
46	MC Offshore Petroleum, LLC	23567-1	GT-01	NGT	0.0004	0.000712
47	MC Offshore Petroleum, LLC	23567-1	GT-02	NGT	0.0004	0.000712
48	MC Offshore Petroleum, LLC	23567-1	GT-03	NGT	0.0004	0.000712
49	MC Offshore Petroleum, LLC	23583-1	GT-01	NGT	0.0004	0.000712
50	MC Offshore Petroleum, LLC	23583-1	GT-02	NGT	0.0004	0.000712
87	MC Offshore Petroleum, LLC	70004-1	NGT106	NGT	0.0004	0.000712
88	MC Offshore Petroleum, LLC	70004-1	NGT107	NGT	0.0004	0.000712
89	MC Offshore Petroleum, LLC	70004-1	NGT108	NGT	0.0004	0.000712
90	MC Offshore Petroleum, LLC	70004-1	NGT109	NGT	0.0004	0.000712

Table 70: Summary of emission units with incorrect sulfur values for NGT (i.e., sulfur content for diesel fuel was used) in the 2021 draft data

#	Company Name	Facility ID	2021 Emission Unit ID	Process ID	Pre- Corrective Action Fuel Sulfur Content [wt%]	Post - Corrective Action Fuel Sulfur Content [wt%]
1	ANKOR Energy LLC	21-1	GEN1	NGT	0.0015	0.000712
2	ANKOR Energy LLC	21472-1	GEN1	NGT	0.0015	0.0006
3	ANKOR Energy LLC	21472-1	XPUMP1	NGT	0.0015	0.0006
4	BP Exploration & Production Inc.	1001-1	CT-01	NGT	0.0015	0.000338
5	BP Exploration & Production Inc.	1001-1	CT-02	NGT	0.0015	0.000338
6	BP Exploration & Production Inc.	1001-1	GT-01B	NGT	0.0015	0.000338
7	BP Exploration & Production Inc.	1001-1	GT-02B	NGT	0.0015	0.000338
8	BP Exploration & Production Inc.	1001-1	GT-03B	NGT	0.0015	0.000338
9	BP Exploration & Production Inc.	1001-1	GT-04B	NGT	0.0015	0.000338
10	BP Exploration & Production Inc.	1001-1	GT-05B	NGT	0.0015	0.000338
11	BP Exploration & Production Inc.	1101-1	GT-01B	NGT	0.0015	0.000338
12	BP Exploration & Production Inc.	1101-1	GT-02B	NGT	0.0015	0.000338
13	BP Exploration & Production Inc.	1101-1	GT-03B	NGT	0.0015	0.000338
14	BP Exploration & Production Inc.	1101-1	GT-04B	NGT	0.0015	0.000338
15	BP Exploration & Production Inc.	1101-1	GT-05B	NGT	0.0015	0.000338
16	BP Exploration & Production Inc.	1215-1	CT-01	NGT	0.0015	0.000338
17	BP Exploration & Production Inc.	1215-1	CT-02	NGT	0.0015	0.000338
18	BP Exploration & Production Inc.	1215-1	GT-01	NGT	0.0015	0.000338
19	BP Exploration & Production Inc.	1215-1	GT-02	NGT	0.0015	0.000338
20	BP Exploration & Production Inc.	1215-1	GT-03	NGT	0.0015	0.000338
21	BP Exploration & Production Inc.	1223-1	GT-01B	NGT	0.0015	0.000338
22	BP Exploration & Production Inc.	1223-1	GT-02B	NGT	0.0015	0.000338
23	BP Exploration & Production Inc.	1223-1	GT-03B	NGT	0.0015	0.000338
24	BP Exploration & Production Inc.	2665-1	GE-04	NGT	0.0015	0.000338
25	BP Exploration & Production Inc.	2665-1	GE-05	NGT	0.0015	0.000338
26	BP Exploration & Production Inc.	2665-1	GE-06	NGT	0.0015	0.000338
27	Cantium, LLC	20468-1	CBA301	NGT	0.0015	0.0015
28	GOM Shelf LLC	20021-2	GEN-1	NGT	0.0015	0.0007364

Table 71: Summary of diesel-powered turbines with low sulfur content in the 2021 draft data as compared to the 2017 effort

#	Company Name	Facility ID	2021 Emission Unit ID	Process ID	Pre- Corrective Action Fuel Sulfur Content [wt%]	Post - Corrective Action Fuel Sulfur Content [wt%]
1	Anadarko Petroleum Corporation	1035-1	GT-03A	NGT-D	0.0004	0.0015
2	Anadarko Petroleum Corporation	876-1	GT-01A	NGT-D	0.0004	0.0015
3	Anadarko Petroleum Corporation	876-1	GT-02A	NGT-D	0.0004	0.0015
4	Anadarko Petroleum Corporation	876-1	GT-03A	NGT-D	0.0004	0.0015
5	Exxon Mobil Corporation	183-1	NGT007-D	NGT-D	0.0004	0.0015
6	Exxon Mobil Corporation	183-1	NGT008-D	NGT-D	0.0004	0.0015

6.5.6 Particulate Matter Less Than 10 Microns (PM_{10})

This section's comparison differs slightly from those conducted for other pollutants. PM_{10} emissions reported in the 2021 draft inventory were not speciated into filterable or primary, as opposed to the 2017 final data (Table 60). Consequently, comparing the 2021 draft inventory total PM_{10} emissions (from all equipment types) against the 2017 final PM_{10} emissions does not provide a representative picture of the discrepancies between the two reporting years. However, comparing 2017 final versus 2021 draft inventory PM_{10} is achievable if examined by equipment type because the calculated PM_{10} emissions in the 2021 draft inventory for the boilers, combustion flare pilots, natural gas engines, and turbines represents the filterable PM_{10} emission and can be compared against 2017 final PM_{10} filterable emissions. Similarly, calculated PM_{10} emissions under drilling equipment and diesel engines represent the primary PM_{10} emissions and can be compared against the 2017 final primary PM_{10} emissions. Therefore, in this section, PM_{10} emissions will be broken down by equipment type.

6.5.6.1 Emissions of Particulate Matter Less Than 10 Microns by Equipment Type

Using the Reports module in OCS AQS, PM_{10} emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 22 and Figure 23. Table 72 compares 2021 draft PM_{10} emissions against 2017 final emissions based on PM_{10} species and equipment type. Section 6.6 discusses high percentage changes by equipment type.

Table 72: PM_{10} emissions (tons/year) by inventory year with % change

Equipment Type	PM_{10} Species	2017 Final Emissions	2021 Draft Emissions	Difference	% Change
Boiler/Heater/Burner	PM_{10}-FIL	4.85	2.56	-2.29	- 47%
Combustion Flare–Flare	PM_{10}-PRI	N/A	4.65	-	-
Combustion Flare–Pilot	PM_{10}-FIL	N/A	0.21	-	-
Drilling Equipment	PM_{10}-PRI	8.77	7.87	-0.9	- 10%
Engine – Diesel or Gasoline Engine	PM_{10}-PRI	212	259	47	+ 22%
Engine – Natural Gas	PM_{10}-FIL	158	74.5	-83.5	- 53%
Turbine – Natural Gas, Diesel, or Dual Fuel	PM_{10}-FIL	66.6	72.2	5.6	+ 8%

NOTE: Combustion flare and corresponding pilot processes were excluded from Figure 22 and Figure 23 because those emissions were not reported separately as flare and pilot in the 2017 final data.

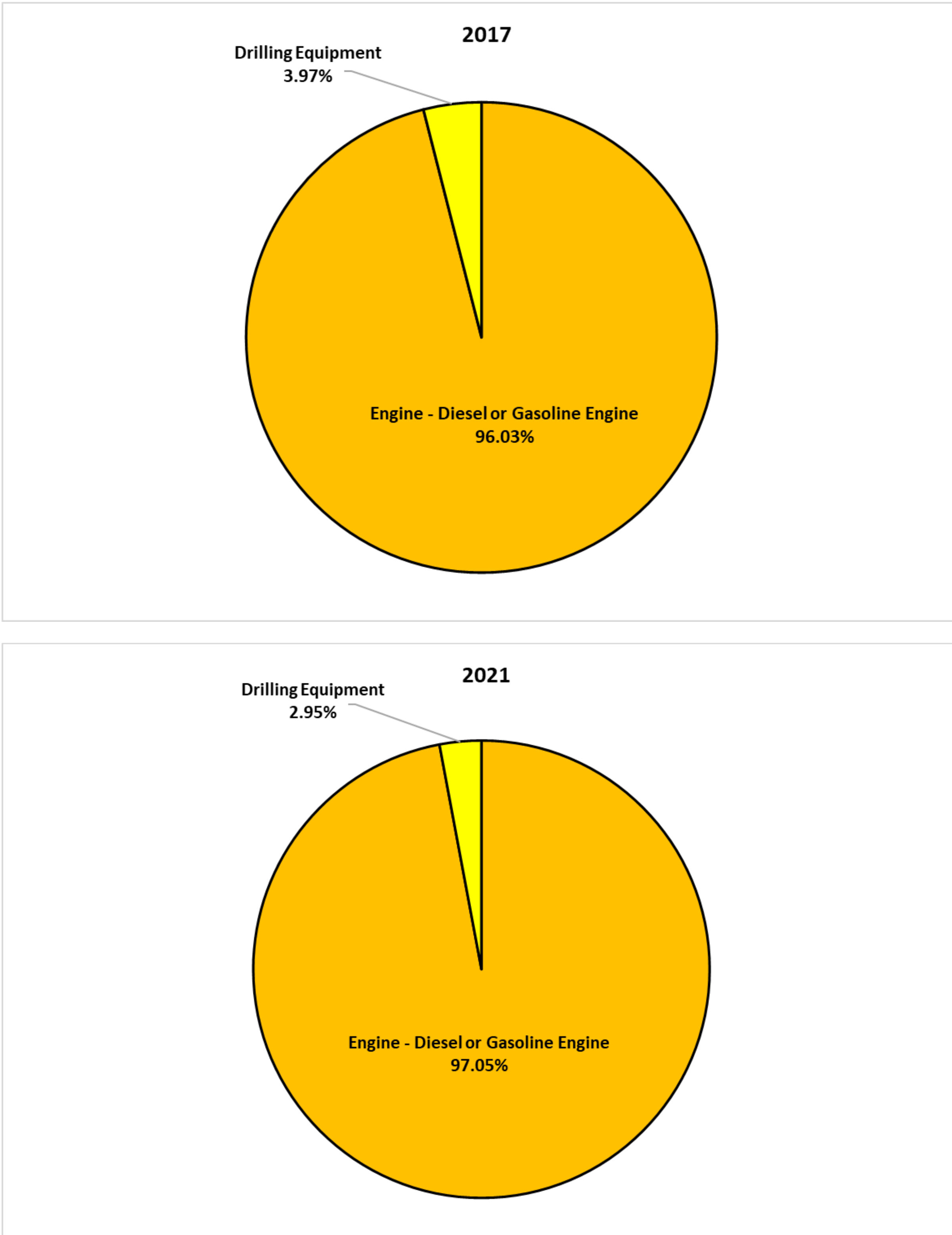


Figure 22: Percentage of PM_{10}-PRI emissions by equipment type (combustion flare and pilot excluded) for 2017 final and 2021 draft data

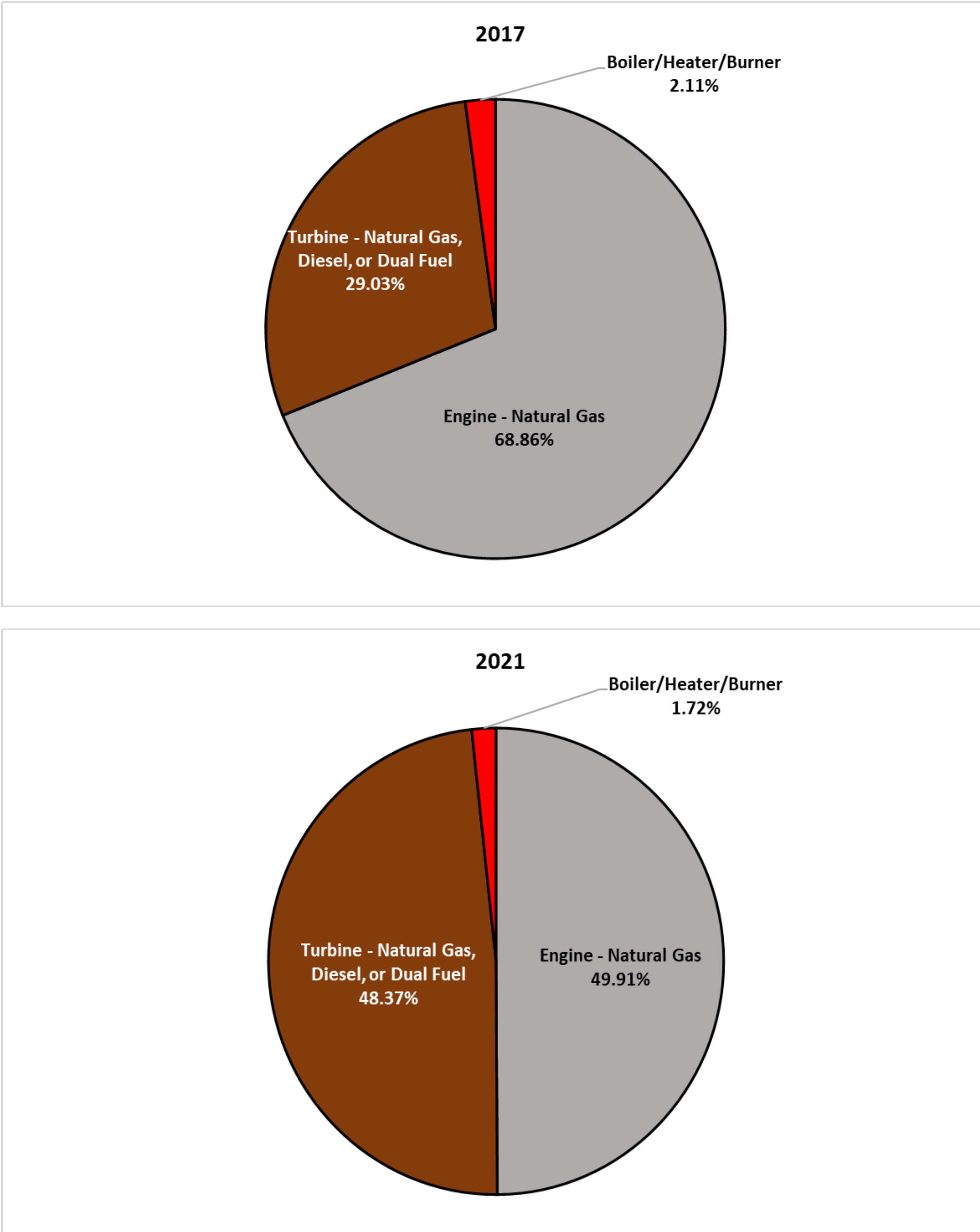


Figure 23: Percentage of PM_{10}-FIL emissions by equipment type (combustion flare and pilot excluded) for 2017 final and 2021 draft data

6.5.7 Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)

This section's comparison differs slightly from those conducted for other pollutants. $PM_{2.5}$ emissions reported in the 2021 draft inventory were not speciated into filterable or primary as opposed to the 2017 final inventory (Table 60). Consequently, comparing the 2021 draft inventory total $PM_{2.5}$ emissions (from all equipment types) against the 2017 final $PM_{2.5}$ emissions does not provide a representative picture of the discrepancies between the two reporting years. However, comparing 2017 final versus 2021 draft inventory $PM_{2.5}$ is achievable if examined on the equipment type level because the calculated $PM_{2.5}$ emissions in the 2021 draft inventory for the boilers, combustion flare pilots, natural gas engines, and turbines represents the filterable $PM_{2.5}$ emissions and can be compared by equipment type against 2017 final $PM_{2.5}$ filterable emissions. Similarly, 2021 draft calculated $PM_{2.5}$ emissions under drilling equipment and diesel engines represent the primary $PM_{2.5}$ emissions and can be compared by equipment type against the 2017 final primary $PM_{2.5}$ emissions. In this section, $PM_{2.5}$ emissions will be broken down by equipment type so that the appropriate evaluation is presented accurately.

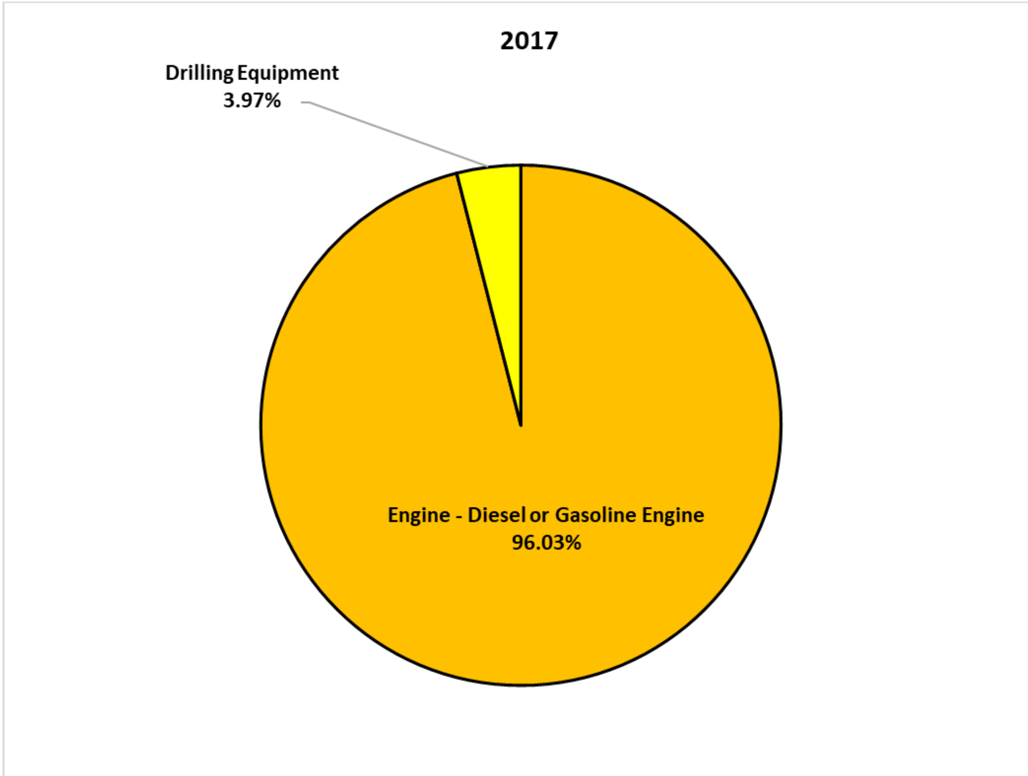
6.5.7.1 Particulate Matter Less Than 2.5 Microns Emissions by Equipment Type

Using the Reports module in OCS AQS, $PM_{2.5}$ emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 24 and Figure 25. Table 73 compares the 2021 draft $PM_{2.5}$ emissions against the 2017 final ones based on the $PM_{2.5}$ species and equipment type. Section 6.6 analyzes high percentages by equipment type.

Table 73: $PM_{2.5}$ emissions (tons/year) by inventory year with % change

Equipment Type	$PM_{2.5}$ Species	2017 Final Emissions	2021 Draft Emissions	Difference	%Change
Boiler/Heater/Burner	$PM_{2.5}$-FIL	4.58	2.52	-2.06	- 45%
Combustion Flare–Flare	$PM_{2.5}$-PRI	N/A	4.45	-	-
Combustion Flare–Pilot	$PM_{2.5}$-FIL	N/A	0.12	-	-
Drilling Equipment	$PM_{2.5}$-PRI	8.77	7.69	-1.08	- 12%
Engine - Diesel or Gasoline Engine	$PM_{2.5}$-PRI	212	252	40	+ 19%
Engine - Natural Gas	$PM_{2.5}$-FIL	158	74.5	-83.5	- 53%
Turbine - Natural Gas, Diesel, or Dual Fuel	$PM_{2.5}$-FIL	66.6	72.2	5.6	+8%

NOTE: Combustion flare and corresponding pilot processes were excluded from the Figure 24 and Figure 25 because those emissions were not reported separately as flare and pilot in the 2017 final.



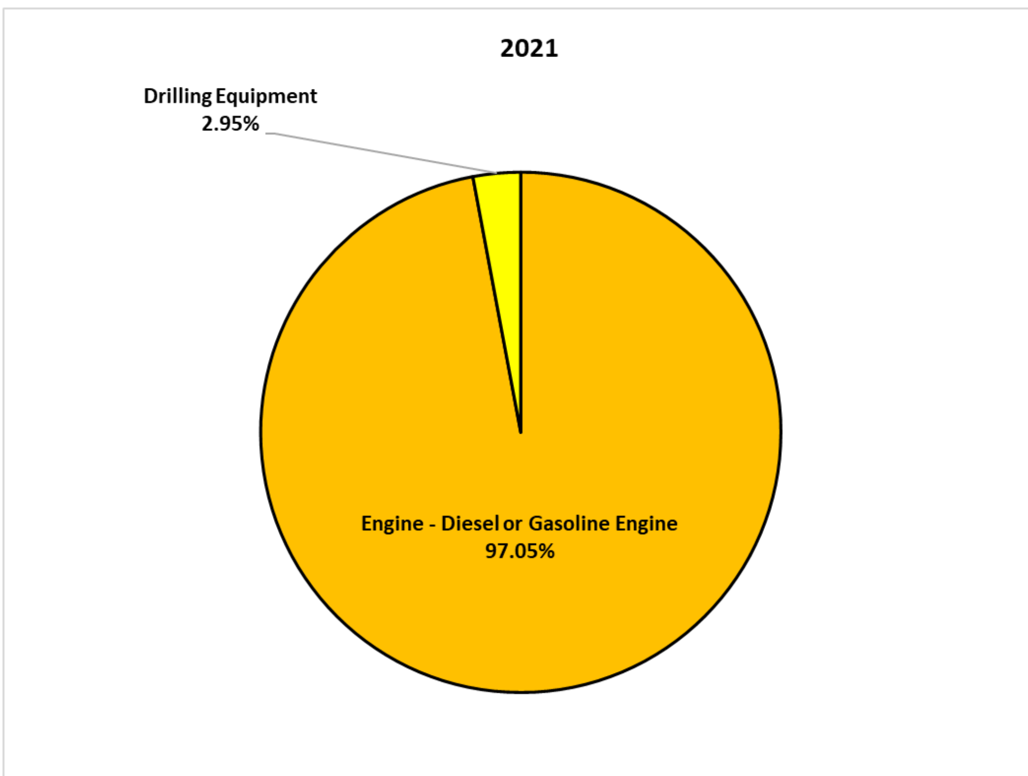
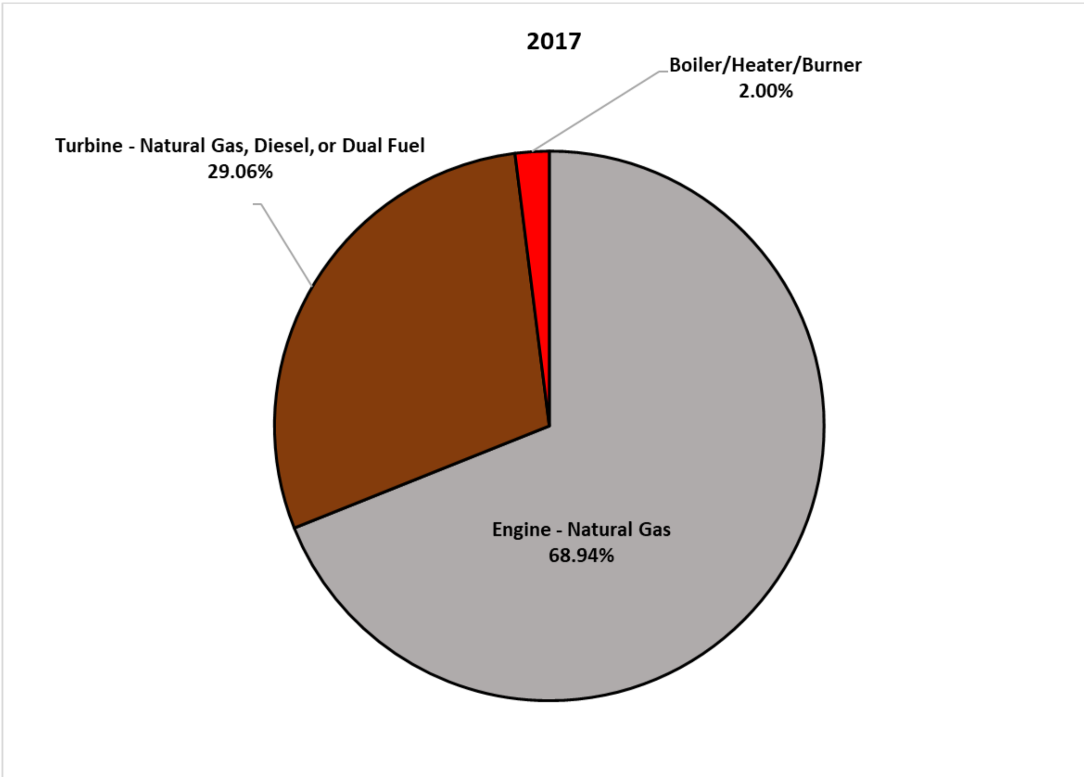


Figure 24: Percentage of $PM_{2.5}$-PRI emissions by equipment type (combustion flare and pilot excluded) for 2017 final and 2021 draft data



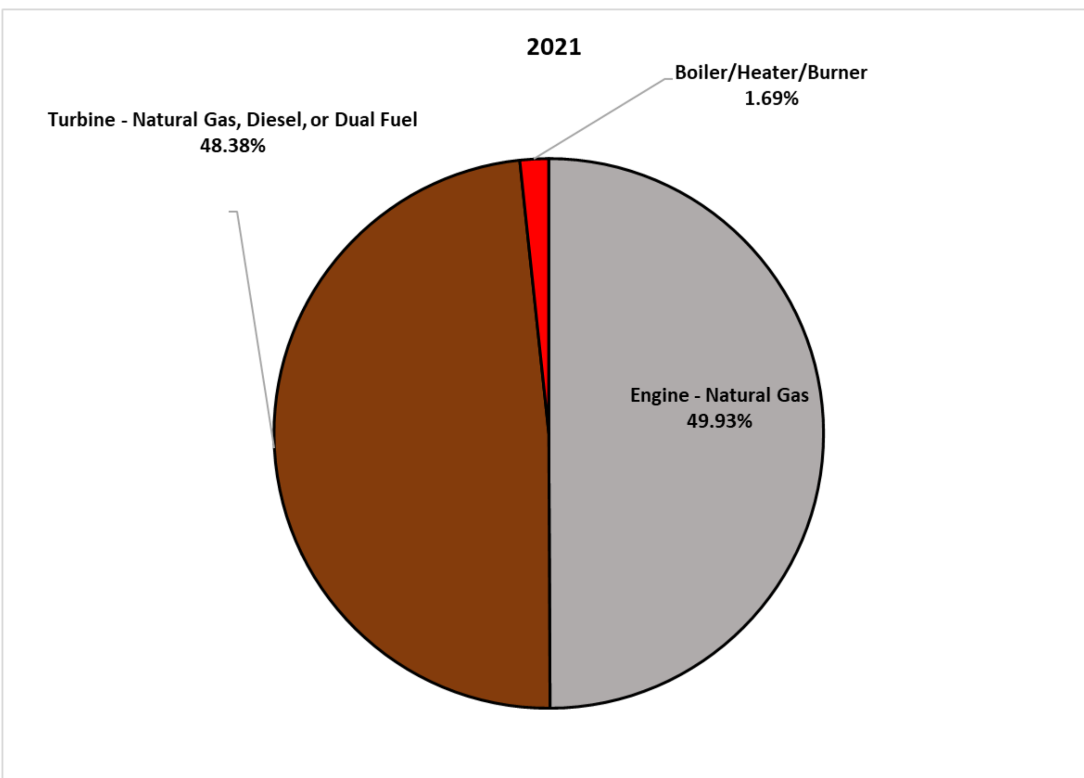


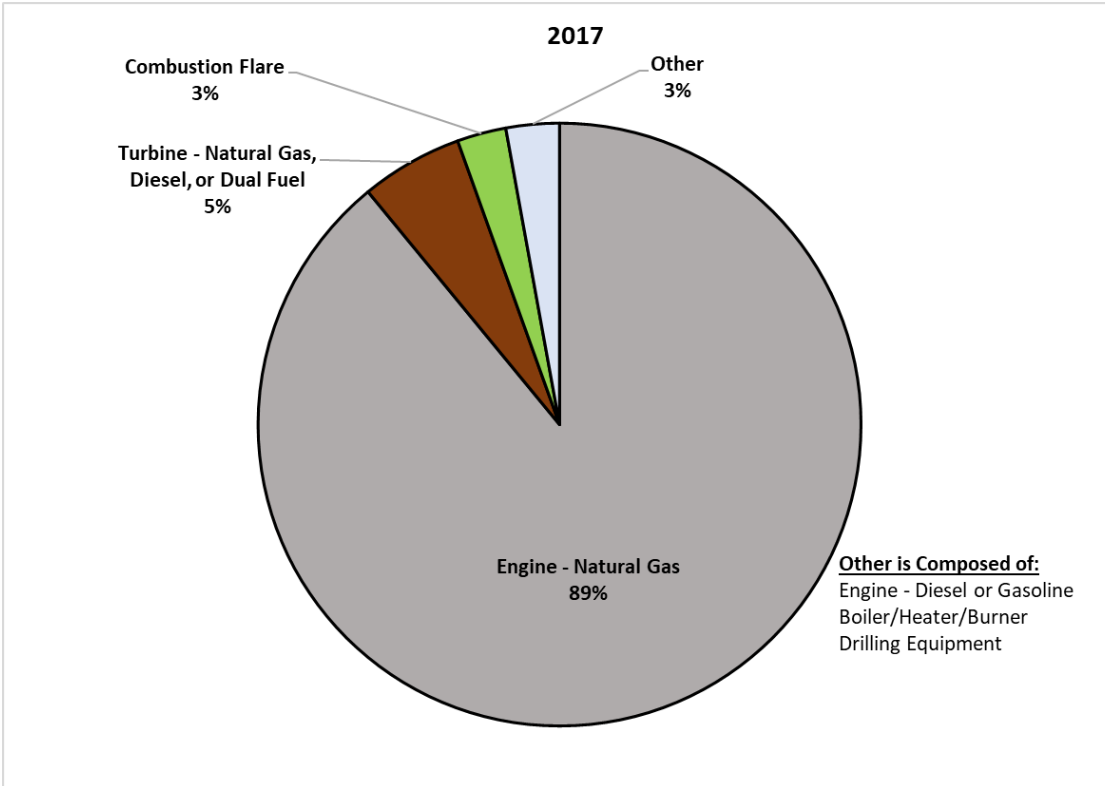
Figure 25: Percentage of $PM_{2.5}$-FIL emissions by equipment type (combustion flare excluded) for 2017 final and 2021 draft

6.5.8 Carbon Monoxide (CO)

Table 60 shows a moderate decrease in the total 2021 final annual emissions of CO compared with 2017 emissions. In the 2021 draft inventory, operators reported 28,387 tons of CO emissions, which is 45.27% lower than the reported emissions in 2017 of 51,872.1 tons.

6.5.8.1 CO Emissions by Equipment Type

Using the Reports module in OCS AQS, CO emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 26. As illustrated, NGE are the highest contributors to the total CO emissions in both inventory years. Therefore, the following sections provide a deeper investigation of NGE units in the 2021 draft and 2017 final inventories to identify data- or calculation-related issues.



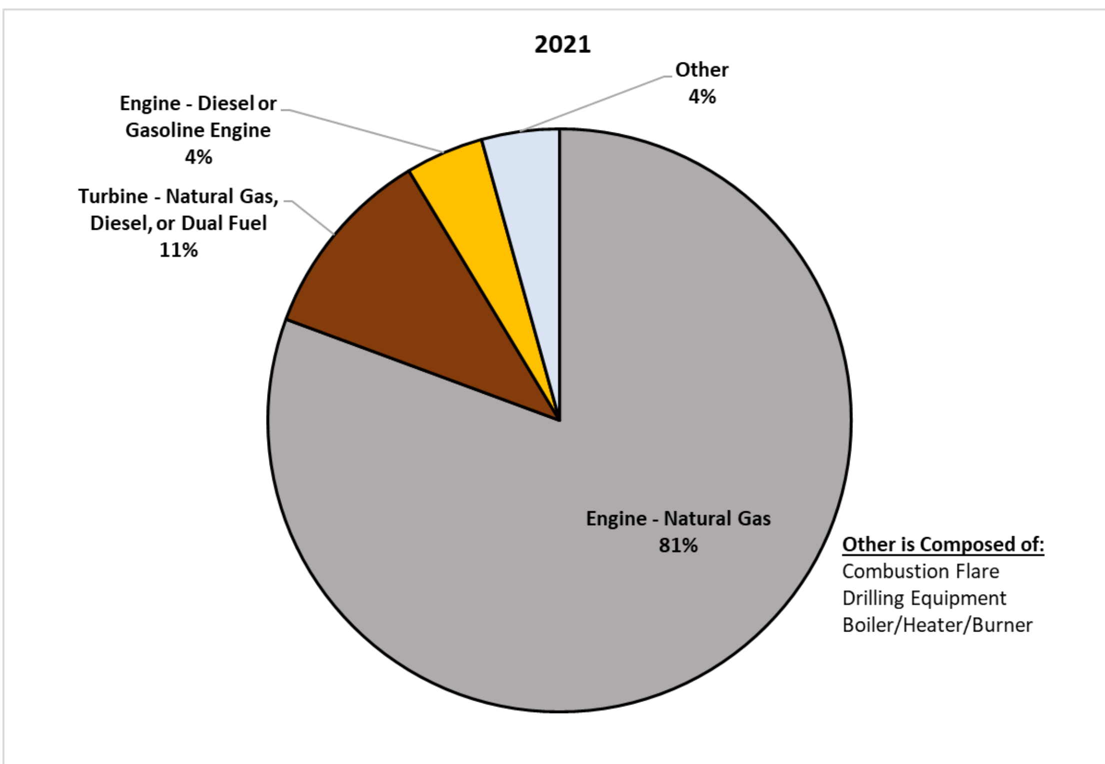


Figure 26: Percentage of CO emissions by equipment type for 2017 final and 2021 draft data

6.5.8.2 Decrease in CO Emissions – Investigations

6.5.8.2.1 Investigations on NGE CO Emissions

CO emissions from NGE are calculated using the following equation (Wilson et al. 2019):

$$E_{CO} = EF_{CO} \times 10^{-3} \times H \times U \qquad (Eq. 81)$$

The above equation indicates that the calculated emissions are directly proportional to the EF and the Fuel Usage (U). This makes the engine throughput (i.e., Fuel usage, U) and the CO EF (EF_{CO}) possible causes for the decrease in CO emissions. Therefore, the quality of data provided for the NGE units will be further investigated.

> ***NOTE:*** The Fuel Heat Value (H**)** also has a direct impact; however, this property is intensive and depends on the fuel type.

6.5.8.2.2 Investigations on NGE Throughputs

As previously mentioned, based on the equation above (*Eq.* 81), a decrease in the throughput corresponds to the decrease in emissions. Therefore, comparing the total annual throughput for NGE would only be valid if the overall count of NGE units is also analyzed.

The count of NGE processes reported in the 2021 effort increased by 4.17%, but only 708 of 1,199 NGE processes were actively emitting (Table 74); the remaining NGE belonged to non-operating facilities or were reported as zero emissions processes. As a result of the 38.49% decrease in the count of emitting NGE processes, the annual fuel usage by emitting processes decreased by 54.73%. NGE equipment contributed 89% to the total CO emissions, and the 54.73% decrease in the throughput to those engines resulted in the observed 45% decrease in the total CO emissions in the 2021 draft data. Therefore, no further analysis or corrective action was conducted on the 2021 draft activity data in this section. In future inventory efforts, operators will be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data to BOEM.

Table 74: Comparison of NGE throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Natural Gas Processes Reported in the Inventory	1,151	1,199	+ 4.17%
Number of **Active Emitting** Natural Gas Processes	1,151 of 1,151	708 of 1,199	- 38.49%
Total Fuel Usage by Active Emitting Processes [Mscf]	33,872,765	15,334,732	- 54.73%

6.5.9 Nitrogen Oxides (NO_x)

Table 60 shows a moderate decrease in the total 2021 draft annual NO_x emissions. In the 2021 draft inventory, operators reported 34,651 tons of NO_x emissions, which is 30.6% lower than the reported emissions in 2017 of 49,962 tons.

6.5.9.1 NO_x Emissions by Equipment Type

Using the Reports module in OCS AQS, NO_x emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 27. NGEs are the highest contributors to total

NO_x emissions in both inventory years. Therefore, the following sections provide a deeper investigation of NGE units in the 2021 draft and 2017 final inventories to identify data- or calculation-related issues.

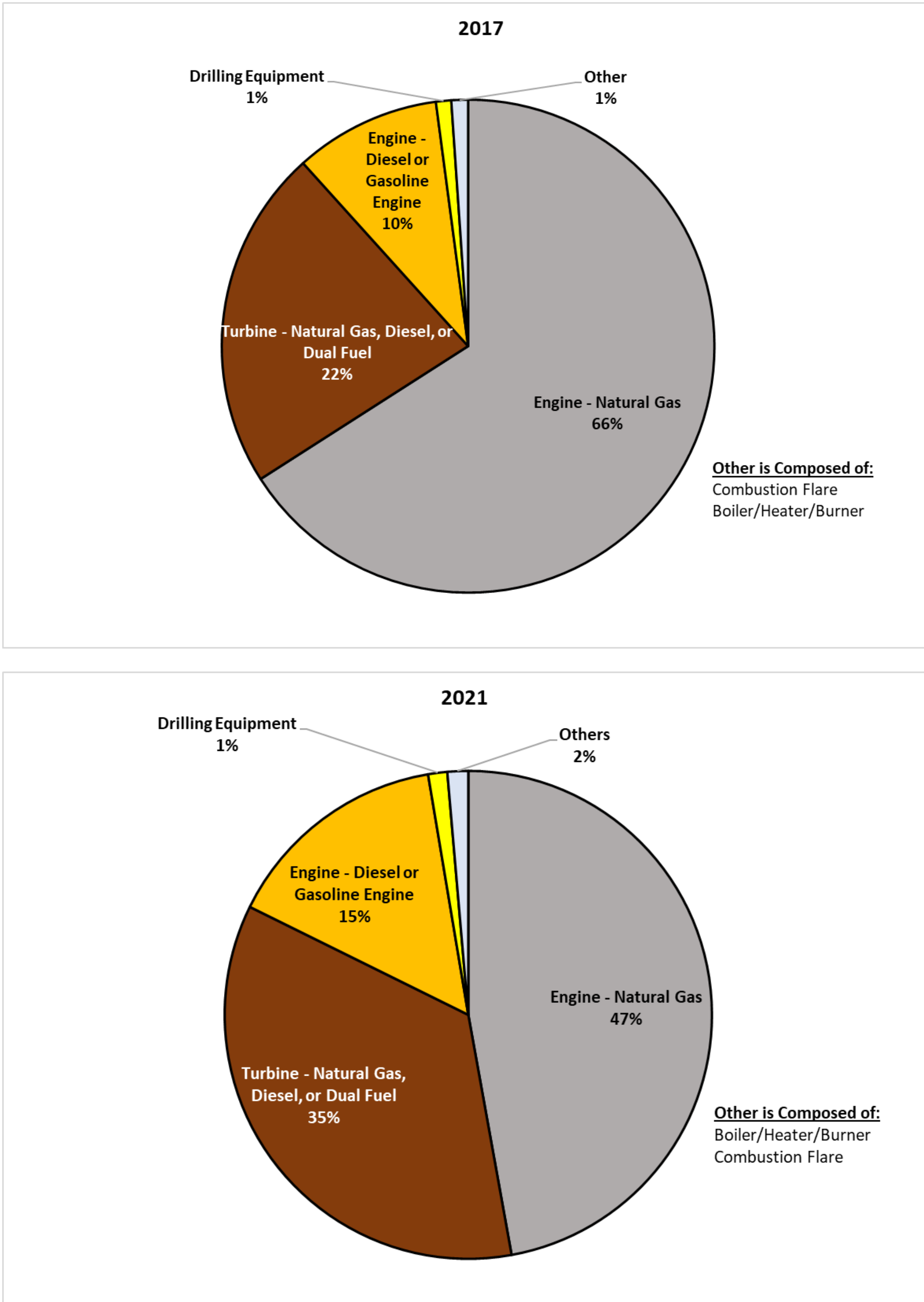


Figure 27: Percentage of nitrogen oxides emissions by equipment type for 2017 final and 2021 draft data

6.5.9.2 Decrease in NO_x Emissions – Investigations

6.5.9.2.1 Investigations on NGE NO_x Emissions

NO_x emissions from NGE are calculated using the following equation (Wilson et al. 2019):

$$E_{NOx} = EF_{NOx} \times 10^{-3} \times H \times U \qquad (Eq. 82)$$

The above equation indicates that the calculated emissions are directly proportional to the EF and Fuel Usage (U). This makes the engine throughput (i.e., Fuel Usage, U) and the NO_x EF (EF_{NOx}) possible causes for the decrease in NO_x emissions. Therefore, the quality of data provided for the NGE emission units will be further investigated.

> ***NOTE:*** The Fuel Heat Value (H) also has a direct impact; however, this property is intensive and depends on the fuel type.

6.5.9.2.2 Investigations on NGE Throughputs

Based on Eq. 82 shown above, a decrease in the throughput corresponds to a decrease in emissions. Therefore, comparing the total annual throughput for the NGE would only be valid if the overall count of the NGE units is also analyzed.

The count of NGE processes reported in the 2021 effort increased by 4.17%, and only 708 of 1,199 NGE processes were actively emitting (Table 75); the remaining NGE to non-operating facilities or were reported as zero emissions processes. As a result of the 38.49% decrease in the count of emitting NGE processes, the annual fuel usage by emitting processes decreased by 54.73%. NGEs contributed 66% to the total NO_x emissions in the 2017 final, and the 54.73% decrease in throughput to those engines resulted in the observed 30.6% decrease in the total NO_x emissions in the 2021 draft data. Therefore, no further analysis or corrective action was conducted on the 2021 draft activity data in this section. In future inventory efforts, operators will be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data to BOEM.

Table 75: Comparison of NGE throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Natural Gas Processes Reported in the Inventory	1,151	1,199	+ 4.17%
Number of **Active Emitting** Natural Gas Processes	1,151 of 1,151	708 of 1,199	- 38.49%
Total Fuel Usage by Active Emitting Processes [Mscf]	33,872,765	15,334,732	- 54.73%

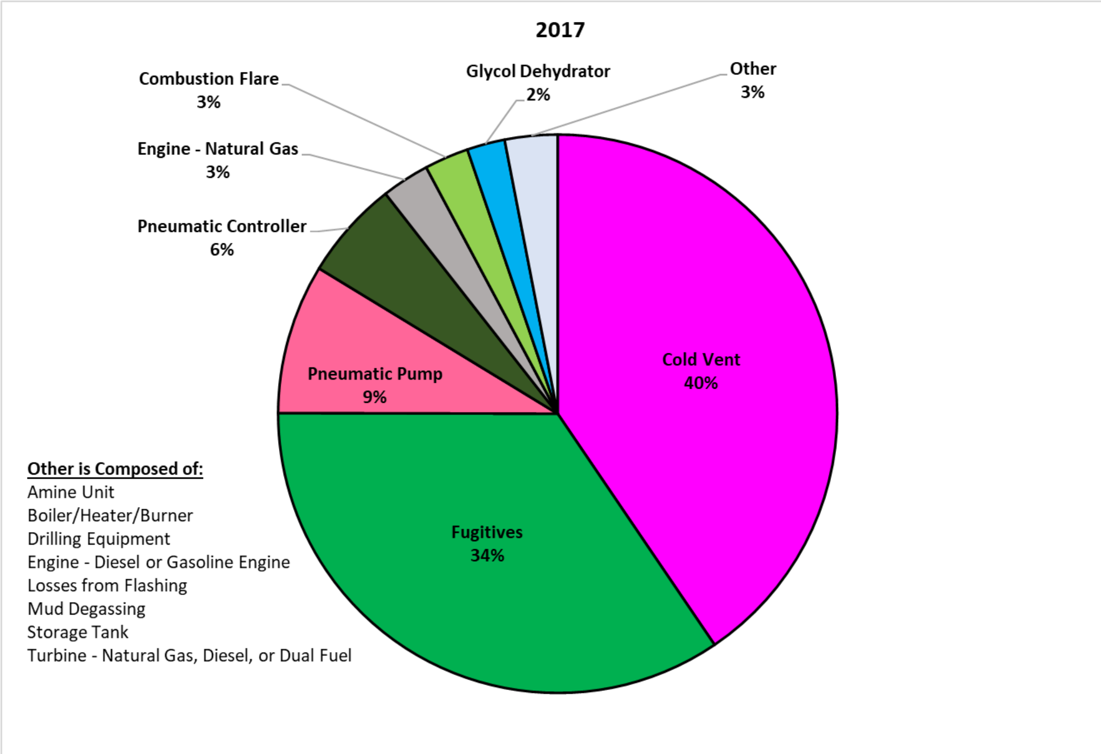
6.5.10 Volatile Organic Compounds (VOC)

Table 60 shows a minimal increase in the total 2021 draft annual emissions of VOC. In the 2021 draft inventory, operators reported 39,727 tons of VOC emissions, which is 2.3% higher than the reported emissions in the 2017 final data of 38,832 tons.

6.5.10.1 VOC Emissions by Equipment Type

Using the Reports module in OCS AQS, VOC emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 28. As illustrated, cold vents (VEN) are the highest contributors to the total VOC emissions in both inventory years. The overall VOC emissions in both inventory years (2017 final and 2021 draft) are approximately comparable, and no further analysis and corrective actions were conducted on the 2021 draft activity data.

> ***NOTE:*** Although VOC annual emissions in the 2021 draft inventory were comparable to those in the 2017 final inventory and no further investigations were conducted in this section, the calculated VOC emissions under cold vents were overestimated in the 2021 draft inventory (as described in Section 6.6.4.2.1) due to the high VOC reported concentrations in vented gas that the operators provided in the data requests of cold vents. The Team requested corrective actions to fix those values, which ultimately changed the total VOC emissions in the 2021 final data (Section 6.6.4.2.1). This example demonstrates that comparing 2017 final and 2021 draft inventories by equipment type can reveal discrepancies and data entry issues.



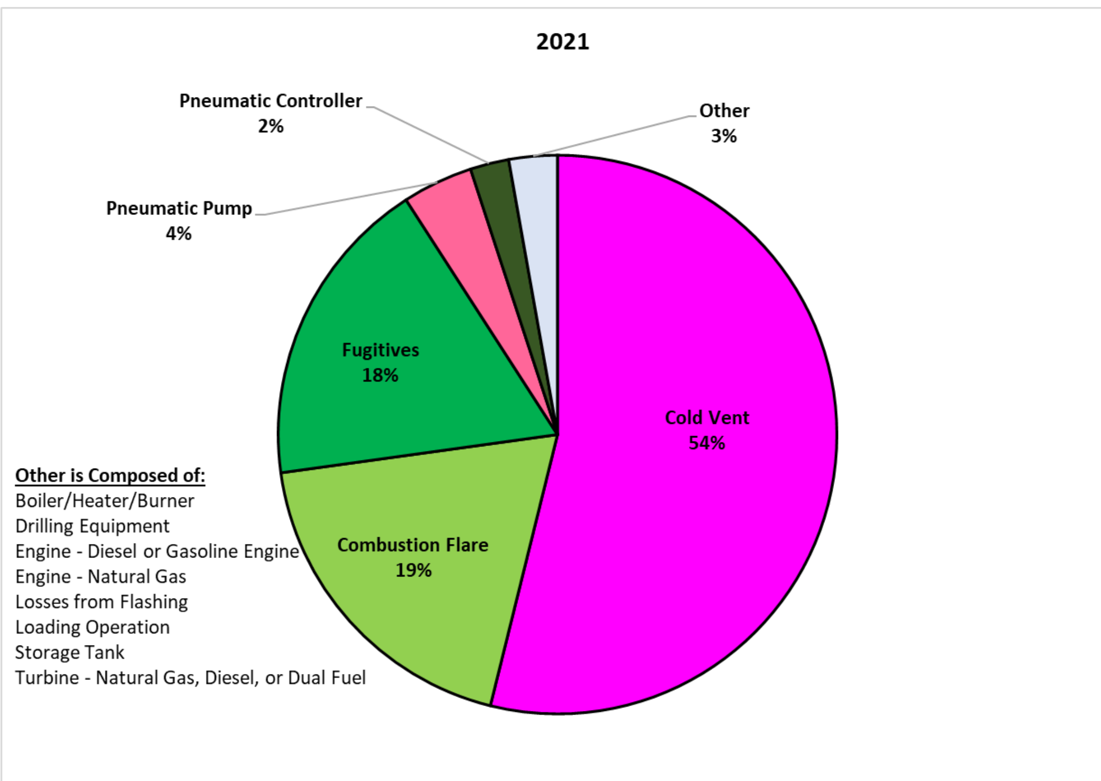


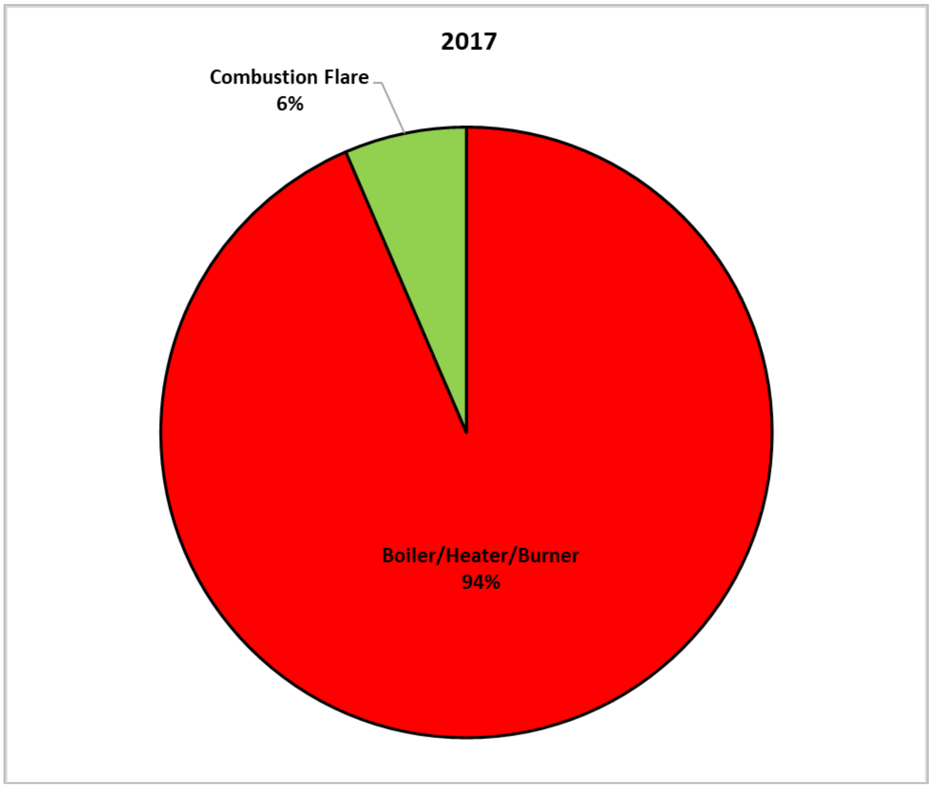
Figure 28: Percentage of VOCs by equipment type for 2017 final and 2021 draft data

6.5.11 Ammonia (NH_3)

Table 60 shows a moderate decrease in the total 2021 draft annual emissions of NH_3. In the 2021 draft inventory, operators reported 4.614 tons of NH_3 emissions, which is 45% lower than the reported emissions in the 2017 final data of 8.394 tons.

6.5.11.1 NH_3 Emissions by Equipment Type

Using the Reports module in OCS AQS, the NH_3 emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 29. As illustrated, boilers/heaters/burners (BOI) are the highest contributors to the total NH_3 emissions in both inventory years. Therefore, the following sections provide a deeper investigation of BOI units in the 2021 draft and 2017 final inventories.



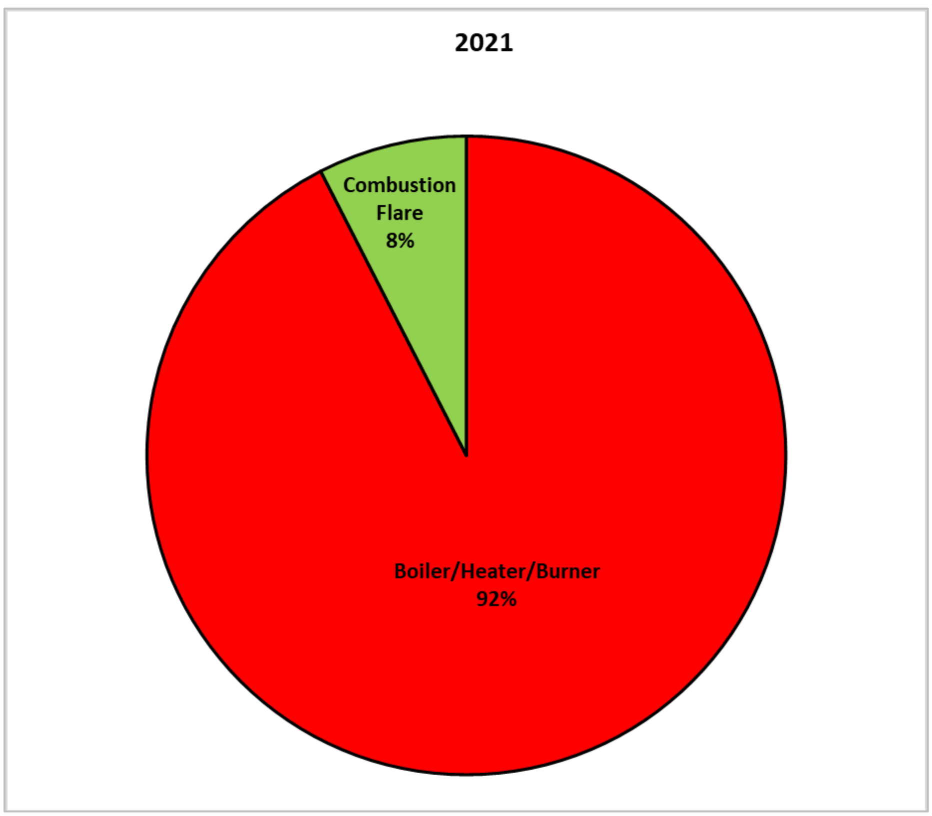


Figure 29: Percentage of NH_3 emissions by equipment type for 2017 final and 2021 draft data

6.5.11.2 Decrease in Ammonia Emissions – Investigations

6.5.11.2.1 Investigations on Boilers/Heaters/Burners NH_3 Emissions

NH_3 emissions from boilers/heaters/burners are calculated using the following equation (Wilson et al. 2019):

$$E_{NH_3} = EF_{NH_3} \times 0.001 \times H \times U \qquad (Eq. 83)$$

The above equation indicates that the calculated emissions are directly proportional to the EF and Fuel Usage (U). This makes the throughput (i.e., Fuel Usage, U) and the NH_3 EF(EF_{NH_3}) possible causes for the decrease in the NH_3 emissions. Therefore, the quality of data provided for the BOI emission units is further investigated.

> ***NOTE:*** The Fuel Heat Value (H) also has a direct impact; nevertheless, this property is intensive and depends on the fuel type.

6.5.11.2.2 Investigations on BOI Throughputs

Table 76 shows a 6.3% increase of the count of the gas-fueled boiler processes reported in the 2021 draft emissions inventory, but only 246 of 396 gas-fueled boiler processes were actively emitting; the remaining processes belonged to non-operating facilities or were reported as zero emissions processes. As a result of a 38.04% decrease in the count of emitting gas-fueled boiler processes, annual fuel usage by emitting processes decreased by 44.07%. Actively emitting liquid-fueled boiler processes did not change and remained the same in the 2021 draft, but the total annual fuel used by those liquid-fueled boilers decreased by 86.47%. Therefore, the observed 45% decrease in the emissions was due to the decrease in the throughputs to the BOI emission units (both gas and liquid-fueled processes). In future inventory efforts, operators will be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data.

> ***NOTE:*** The 86.47% decrease of the liquid fuel usage by boilers was suspicious and raised some questions because the count of active emitting liquid-fueled boilers did not change between the 2017 final and 2021 draft inventory. With further investigations, it was found that annual liquid fuel usage by one liquid-fueled boiler under Facility ID# 2503-1, operated by Shell Offshore Inc., was 4,125,348.44 lb in 2017 (82% of the total liquid fuel usage in 2017) and 74,690.51 lb in 2021 (98.2% lower than the fuel used in the 2017 final inventory). This substantial change in the fuel usage by that facility caused that observed 86.47% decrease of the boilers' liquid fuel usage in 2021 draft. The Team attempted to contact the operator of Facility ID# 2503-1 via email but did not receive a response.

Table 76: Comparison of BOI throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Gas-Fueled Boiler Processes Reported in the Inventory	397	422	+ 6.30%
Number of **Active Emitting** Gas-Fueled Boiler Processes	397 of 397	246 of 422	- 38.04%
Total Fuel Usage by Active Emitting Gas-Fueled Boiler Processes [Mscf]	4,730,809.44	2,645,770.30	- 44.07%
Number of Liquid-Fueled Boiler Processes Reported in the Inventory	6	7	+ 16.67%

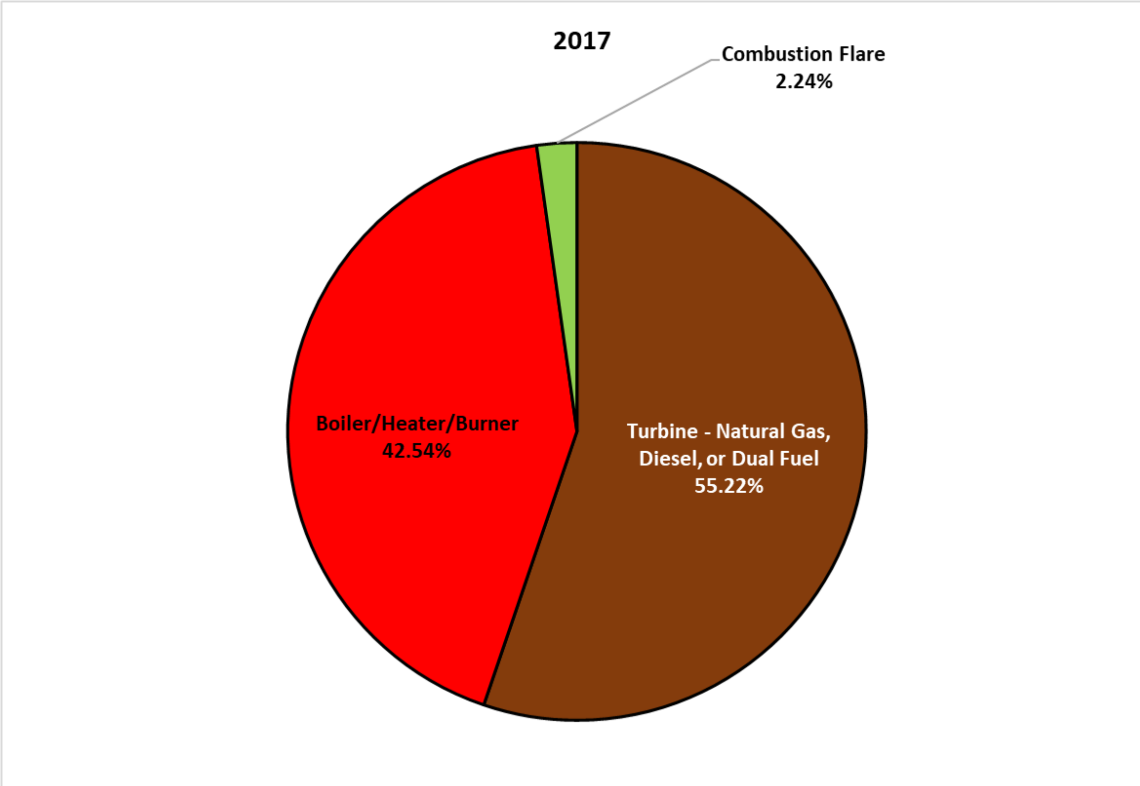
Parameter	2017 Final	2021 Draft	% Change
Number of **Active Emitting** Liquid-Fueled Boiler Processes	6 of 6	6 of 7	0.00%
Total Fuel Usage by Active Emitting Liquid-Fueled Boiler Processes [lb]	5,017,792.04	678,765.31	- 86.47%

6.5.12 Lead (Pb)

Table 60 shows a moderate increase in the total 2021 draft annual emissions of lead (Pb). In the 2021 draft inventory, operators reported 0.0056 tons of Pb emissions, which is 47% higher than the reported emissions in the 2017 final data of 0.0038 tons.

6.5.12.1 Lead Emissions by Equipment Type

Using the Reports module in OCS AQS, Pb emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 30. As illustrated, the NGT were the highest contributor to the total Pb emissions in both inventory years. The following sections provide a deeper investigation of the turbine emission units in the 2021 draft and 2017 final inventories to identify data- or calculation- related issues.



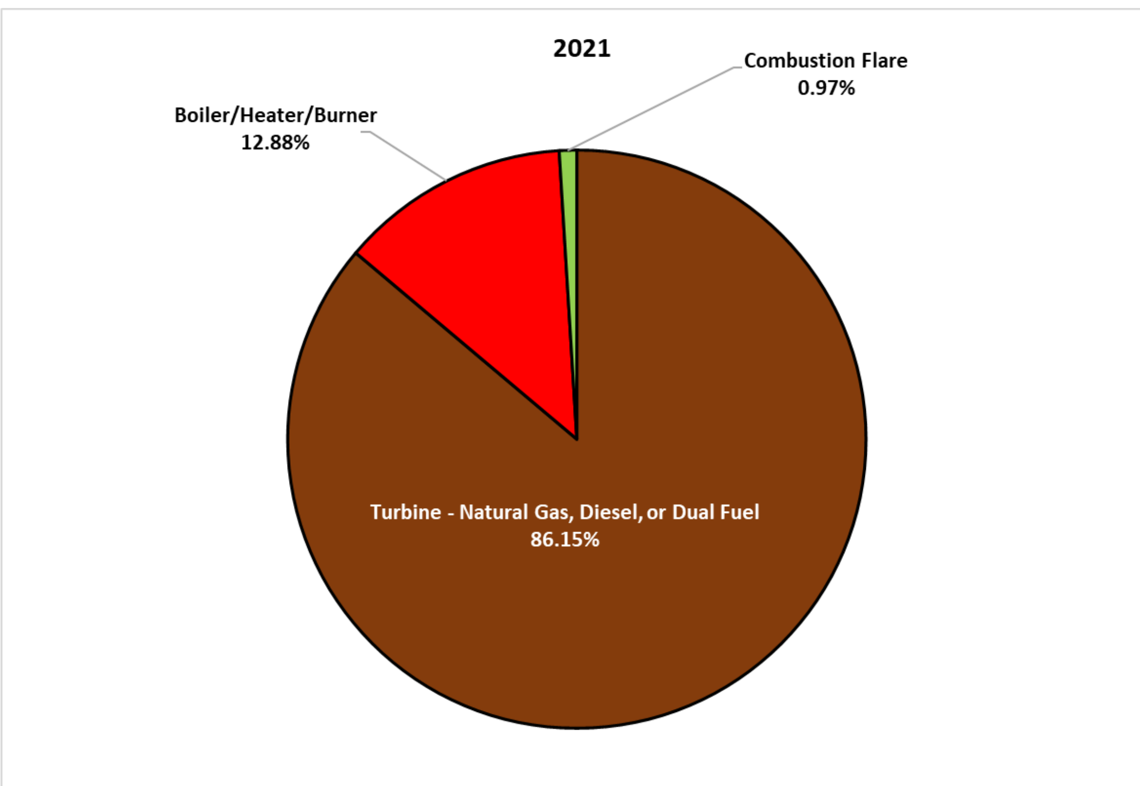


Figure 30: Percentage of lead emissions by equipment type for 2017 final and 2021 draft data

6.5.12.2 Increase in Lead Emissions – Investigations

6.5.12.2.1 Investigations on Turbines Pb Emissions

Lead is specifically emitted by the diesel turbines (NGT-D); therefore, the investigation in the following section was focused on the NGT-D processes only and the quality of data provided for the diesel turbine emission units.

Pb emissions from diesel turbines are calculated using the following equation (Wilson et al. 2019):

$$E_{Pb} = EF_{Pb} \times 10^{-6} \times U \times 7.1 \times 19{,}300 \qquad (Eq. 84)$$

> ***NOTE:*** The above equation indicates that the calculated emissions are directly proportional to the EF in lb/MMBtu and Fuel Usage (U) in gallons. This makes the turbine throughput (i.e., Fuel usage, U) and the Pb EF (EF_{Pb}) possible causes for the increase in Pb emissions.

6.5.12.2.2 Investigations on Diesel Turbines Throughputs

Based on Eq. 84 shown above, an increase in the throughput corresponds to an increase in emissions. Comparing the total annual throughput for the diesel turbines would only be valid if the overall count of the emissions units was also analyzed. Table 77 shows that at the total diesel turbine equipment count increased significantly from the 2017 final to 2021 draft data. Therefore, total throughput of diesel fuel also significantly increased, which, in turn, led to an increase in the Pb emissions in the 2021 data.

Table 77: Comparison of diesel turbines throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of NGT-D Processes Reported in the Inventory	57	111	+ 94.74%
Number of **Active Emitting** NGT-D Processes	57 of 57	89 of 111	+ 56.14%
Total Fuel Usage by Active Emitting Processes [Gallons]	3,468,139.36	5,017,722.15	+ 44.68%

6.5.13 Benzene, Toluene, Ethylbenzene, and Xylene (BTEX)

These four hydrocarbons are emitted from various industrial sources. Their emissions for some equipment types are calculated from VOC emissions (such as cold vents); for others, they are calculated using pre-defined EFs such as combustion equipment.

Table 60 shows that BTEX emissions decreased by considerably high percentages, from 76–89%. Table 78 represents a breakdown of the BTEX emissions in both inventory years. The last row in this table also shows that the aggregated BTEX emissions decreased by 83% in the 2021 draft data.

Table 78: BTEX emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	Percentage Change
Benzene	225.433	49.893	-175.54	- 77.868%
Toluene	226.231	25.249	-200.982	- 88.839%
Ethyl Benzene	17.91	4.234	-13.676	- 76.360%
Xylenes (Mixed Isomers)	101.58	17.623	-83.957	- 82.651%
Aggregated (BTEX)	**571.154**	**96.999**	**-474.155**	**- 83.02%**

6.5.13.1 BTEX Emissions by Equipment Type

Table 79 shows that glycol dehydrators were the highest contributors of BTEX emissions in the 2017 final data. Conversely, the cold vents were the highest emitters of benzene, ethyl benzene, and xylene (toluene is excluded) in the 2021 draft inventory. Glycol dehydrator (GLY) units were the highest emitters of toluene only, by a value considerably lower than the value of the 2017 final inventory (203 tons in the 2017 final vs. 6.83 tons in the 2021 draft data). Figure 31, Figure 32, Figure 33, and Figure 34 provide graphical representations of Table 79.

The following section provides a more in-depth investigation on the glycol dehydrator units in the 2021 draft and 2017 final inventories to reveal any data or modeling-related issues contributing to this considerable reduction in the reported emissions.

Table 79: 2021 draft and 2017 final BTEX emissions (tons/year) by equipment type and inventory year

Equipment Type	Benzene 2017	Benzene 2021	Benzene % Change	Ethyl Benzene 2017	Ethyl Benzene 2021	Ethyl Benzene % Change	Toluene 2017	Toluene 2021	Toluene % Change	Xylene 2017	Xylene 2021	Xylene % Change
Amine Unit	0.00	0.00	-	0.00	0.00	-	8.69E-03	0.00	- 100.00%	0.00	0.00	-
Boiler/Heater/Burner	0.00	2.78E-03	-	2.25E-05	3.04E-6	- 86.49%	1.02E-02	4.79E-03	- 53.04%	0.00	5.21E-06	-
Cold Vent	17.00	***23.10**	+ 35.88%	1.05	***1.43**	+ 36.19%	2.56	3.48	+ 35.94%	4.00	***5.97**	+ 49.25%
Combustion Flare	2.00	5.06	+ 153.00%	0.00	0.29	-	2.14	4.52	+ 111.21%	1.00	1.27	+ 27.00%
Drilling Equipment	0.00	0.11	-	-	-	-	0.04	0.04	- 12.27%	0.00	0.03	-
Engine – Diesel or Gasoline Engine	1.09	1.17	+ 7.34%	-	-	-	0.43	0.47	+ 9.47%	0.30	0.33	+ 9.70%
Engine – Natural Gas	23.80	11.40	- 52.10%	0.62	0.28	- 55.43%	10.00	4.65	- 53.50%	3.50	1.67	- 52.29%
Fugitives	14.50	-	-	0.90	-	-	2.19	-	-	3.74	-	-
Glycol Dehydrator	***159.00**	5.89	- 96.30%	***13.70**	0.88	- 93.55%	***203.00**	***6.83**	- 96.64%	***85.00**	5.28	- 93.79%
Losses from Flashing	0.20	-	-	0.01	-	-	0.03	-	-	0.05	-	-
Pneumatic Controller	2.40	0.96	- 60.04%	0.15	0.06	- 59.86%	0.36	0.15	- 59.94%	0.62	0.25	- 60.00%
Pneumatic Pump	3.63	1.75	- 51.79%	0.23	0.11	- 52.00%	0.55	0.26	- 51.82%	0.94	0.45	- 51.91%
Storage Tank	0.60	-	-	0.04	-	-	0.09	-	-	0.16	-	-
Turbine – Natural Gas, Diesel, or Dual Fuel	0.43	0.47	+ 9.65%	1.11	1.19	+ 7.21%	4.51	4.84	+ 7.32%	2.22	2.38	+7.21%

Notes: * and blue bold text indicates the highest contributor to that pollutant's total in that inventory year.

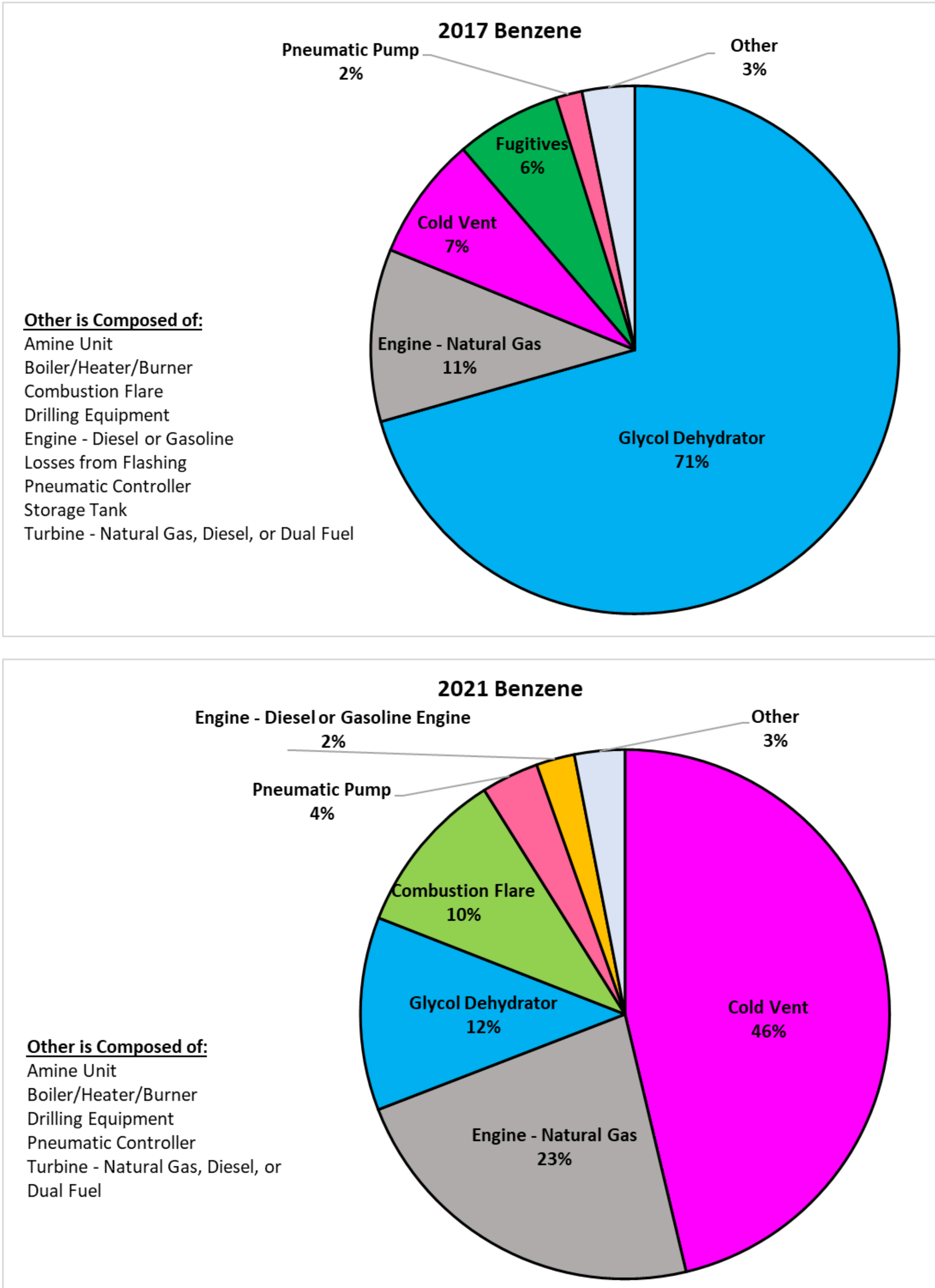


Figure 31: Percentage of benzene emissions by equipment type for 2017 final and 2021 draft data

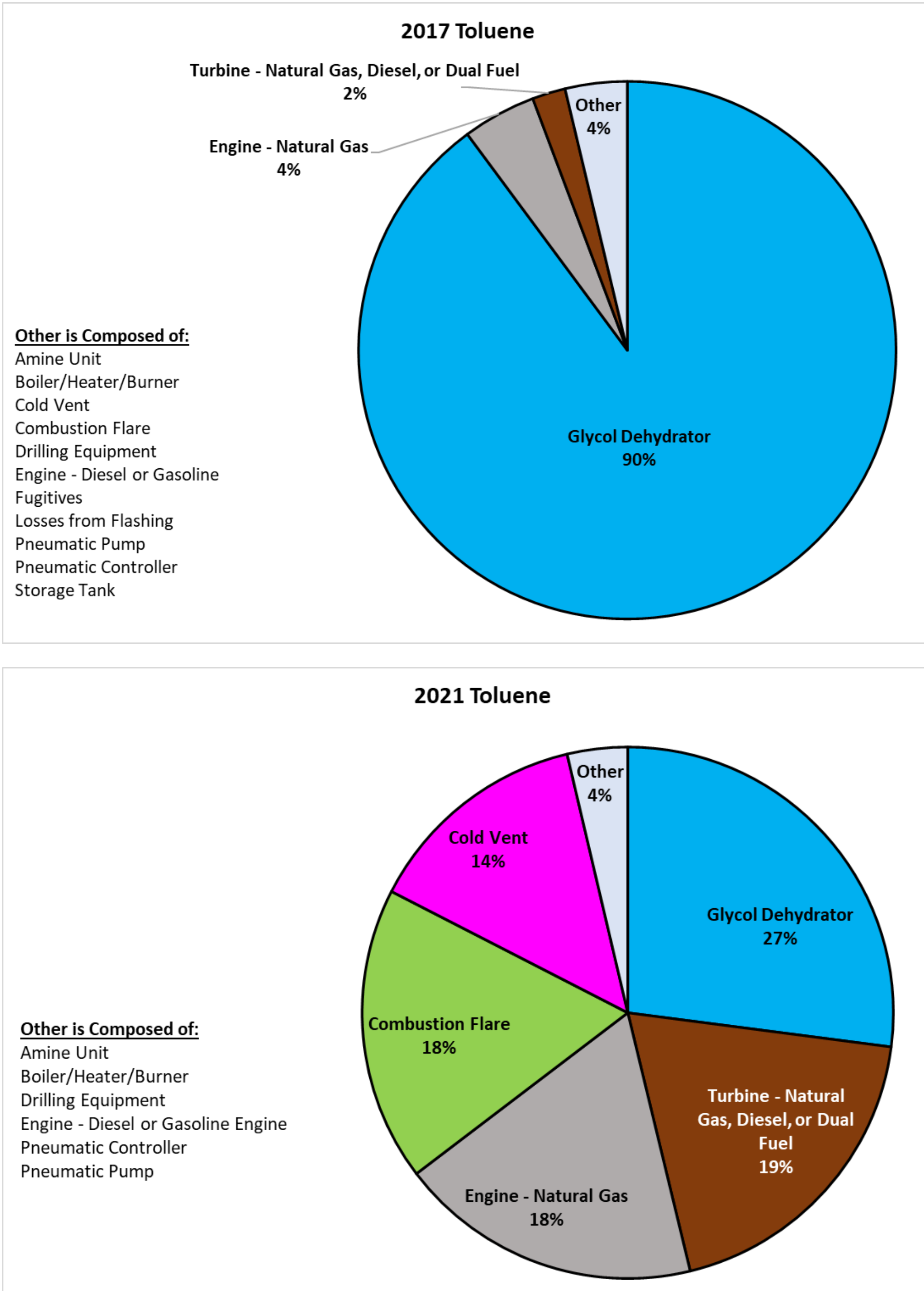
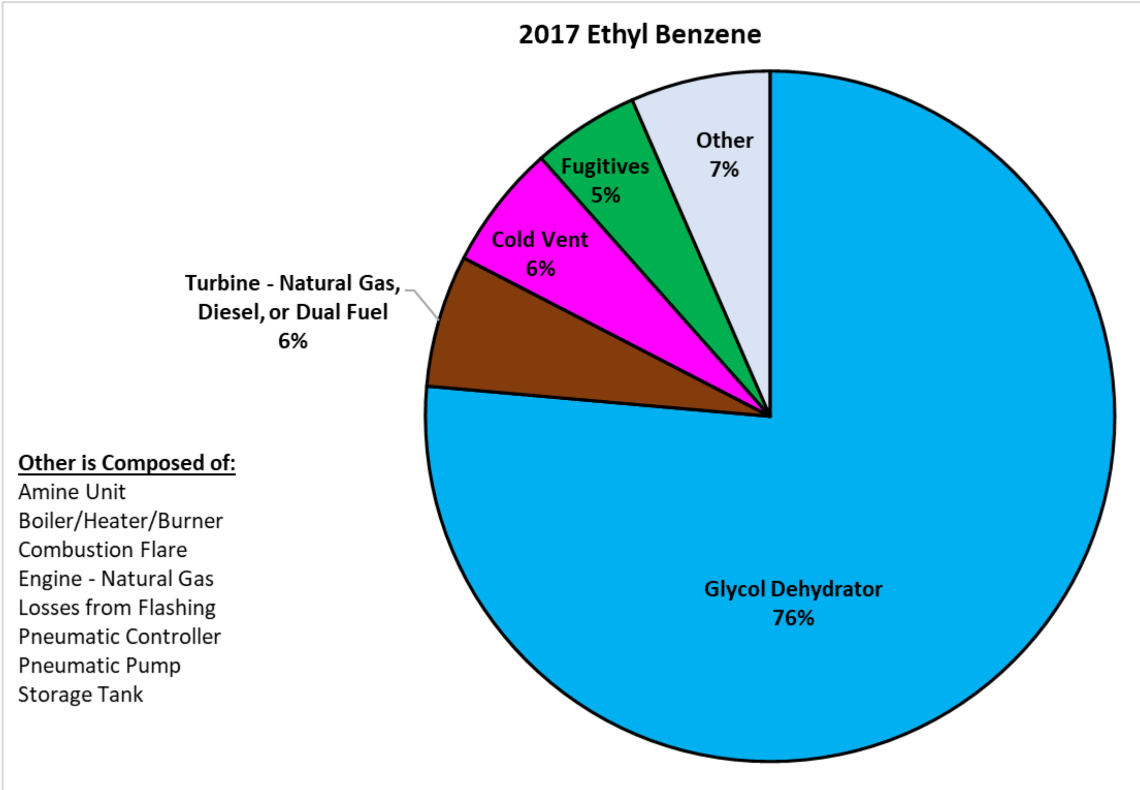


Figure 32: Percentage of toluene emissions by equipment type for 2017 final and 2021 draft data



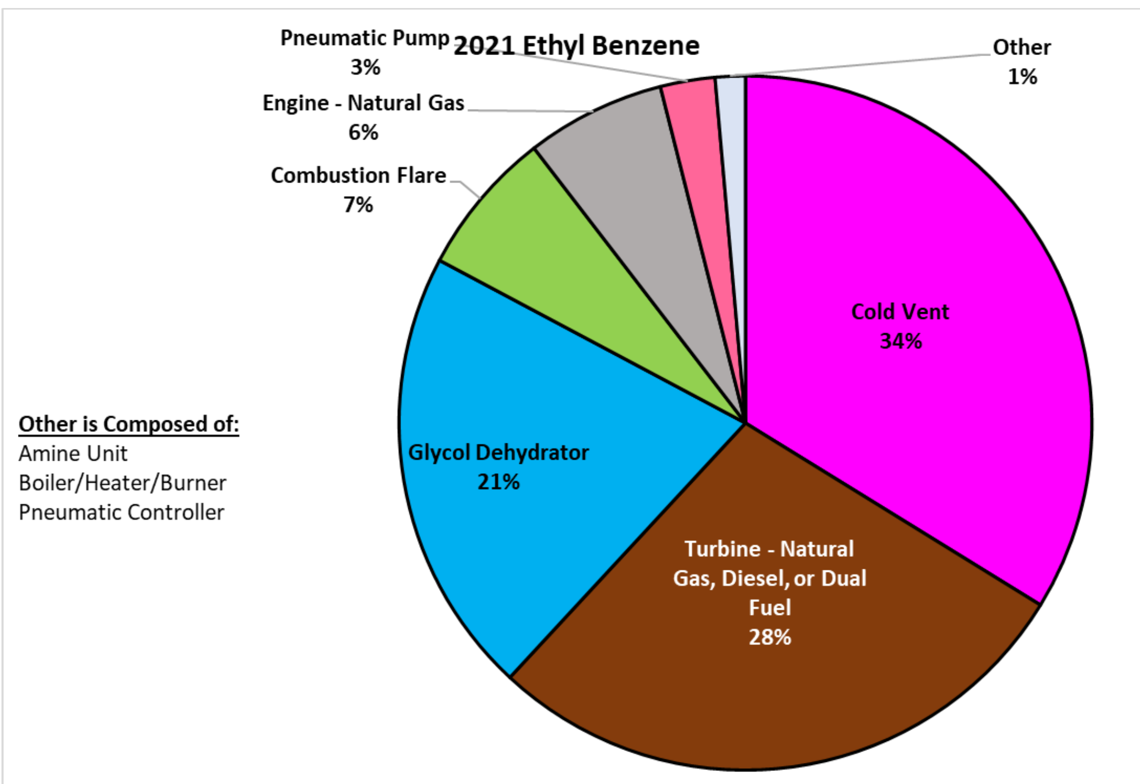
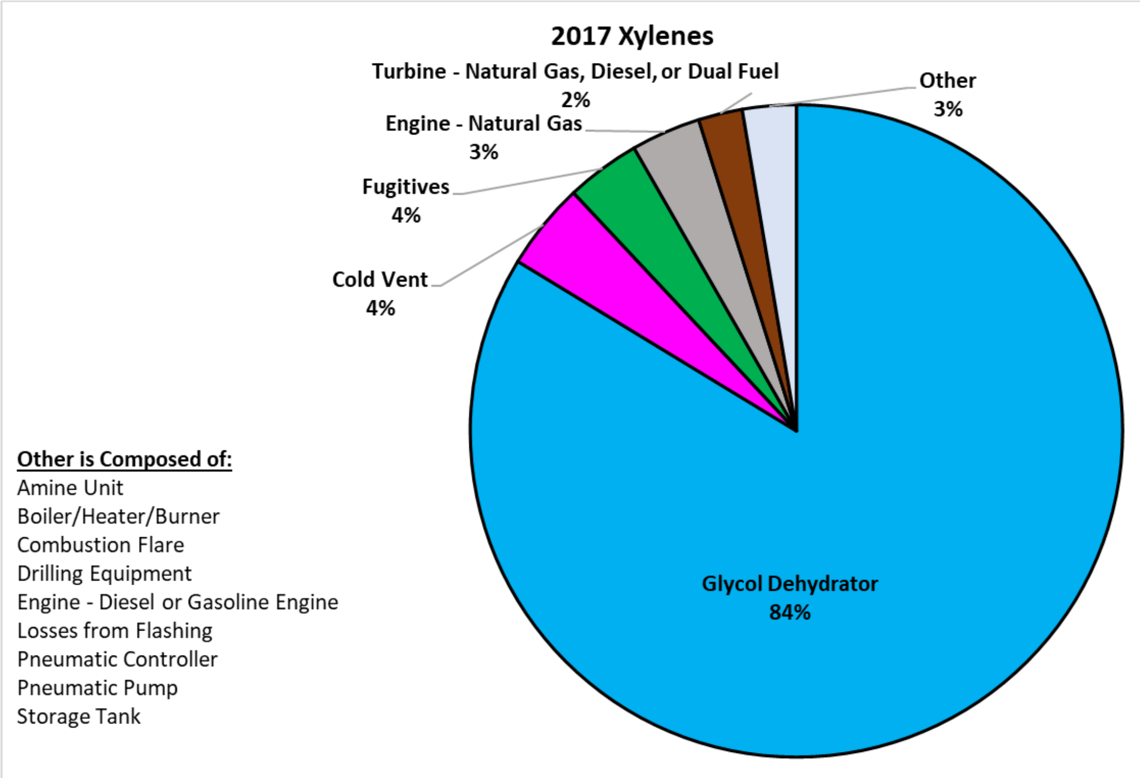


Figure 33: Percentage of ethyl benzene emissions by equipment type for 2017 final and 2021 draft data



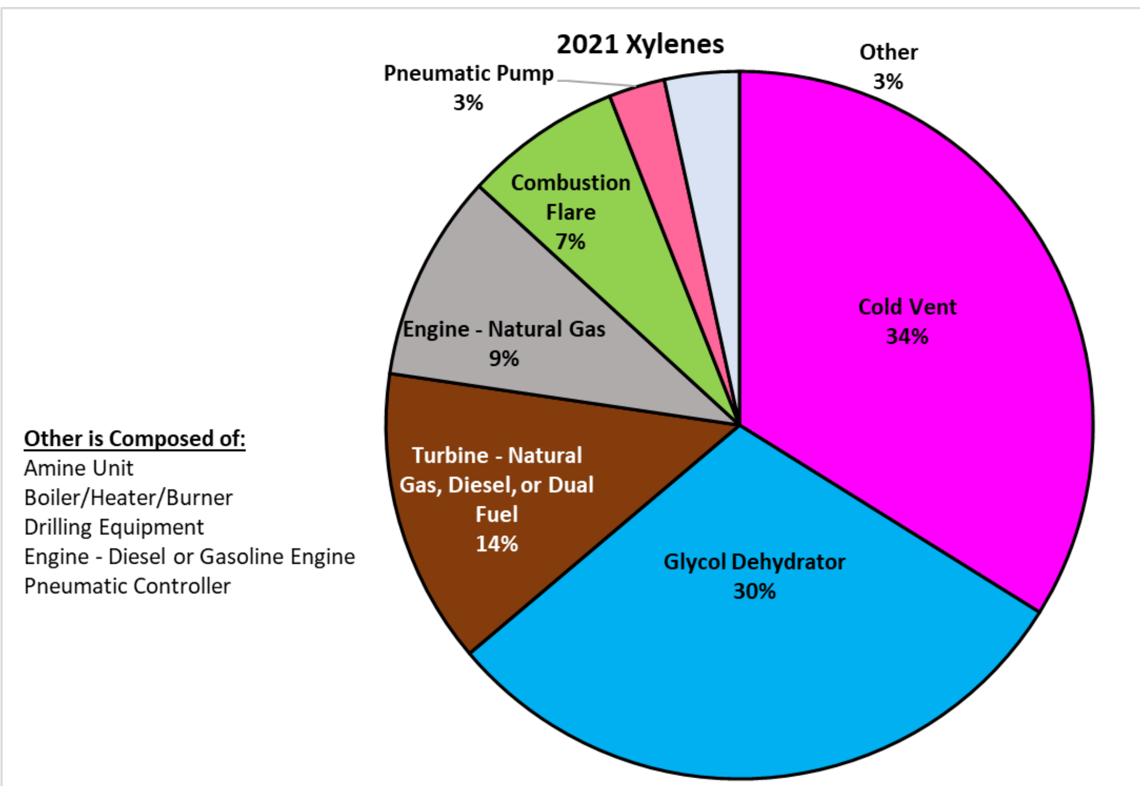


Figure 34: Percentage of xylene emissions by equipment type for 2017 final data and 2021 draft data

NOTE: The considerable decrease in glycol dehydrator contributions to the 2021 benzene emissions is investigated in Section 6.5.13.2.1. BTEX emissions from cold vents (in this case, benzene) are calculated based on cold vent VOC emissions, and the increase in the cold vent contribution to 2021 benzene emissions is a result of the overestimated cold vent VOC emissions in the 2021 draft inventory. That overestimation was caused by erroneously high reporting of VOC concentrations in vented gas. The Team requested corrective actions to fix those values, which ultimately changed the cold vent VOC emissions in the 2021 final data and affected the BTEX emissions from cold vents (Section 6.6.4.2.1). This example demonstrates how comparing the two inventories on the equipment type level and can reveal discrepancies and data entry issues.

NOTE: The considerable decrease in glycol dehydrator contributions to the 2021 toluene emissions is investigated in the Section 6.5.13.2.1. BTEX emissions from cold vents (in this case, toluene) are calculated based on the cold vent VOC emissions, the increase in the cold vent contribution to 2021 toluene emissions is a result of the overestimated cold vent VOC emissions in the 2021 draft inventory. That overestimation was caused by an erroneously high reporting of VOC concentrations in vented gas. The Team requested corrective actions to fix those values, which ultimately changed the cold vent VOC emissions in the 2021 final data (Section 6.6.4.2.1). The observed increase in flare, engine, and turbine contributions result in an increase of their throughput in the 2021 draft inventory.

NOTE: The considerable decrease in glycol dehydrator contributions to the 2021 ethyl benzene emissions is investigated in the following subsection (Section 6.5.13.2.1). BTEX emissions from cold vents (in this case, ethyl benzene) are calculated based on the cold vent VOC emissions. The increase in the cold vent contribution to 2021 ethyl benzene emissions is a result of an overestimated cold vent VOC emissions in the 2021 draft inventory. That overestimation was caused by erroneously high reporting of VOC concentrations in vented gas. The Team requested corrective actions to fix those values, which ultimately changed the cold vents' VOC emissions in the 2021 final data (Section 6.6.4.2.1). The observed increase in flare, engine, and turbine contributions resulted in an increase of their throughput in the 2021 draft inventory.

NOTE: The considerable decrease in glycol dehydrator contribution to the 2021 xylene emissions will be investigated in Section 6.5.13.2.1. BTEX emissions from cold vents (in this case, xylene) are calculated based on the cold vent VOC emissions. The considerable increase in the cold vent contribution to 2021 benzene emissions is a result of the overestimated cold vent VOC emissions in the 2021 draft inventory. That overestimation was caused by erroneously high reporting of VOC concentrations in vented gas. The Team requested corrective actions to fix those values, which ultimately changed the cold vent VOC emissions in the 2021 final data (Section 6.6.4.2.1). The observed increase in flare, engine, and turbine contributions result in the increase of their throughput in the 2021 draft inventory.

6.5.13.2 Decrease in BTEX Emissions – Investigations

6.5.13.2.1 Investigations on Glycol Dehydrators BTEX Emissions

This section analyzes glycol dehydrator (GLY) emission units to determine the reason for the decrease in BTEX emissions. This investigation showed that 106 GLY emission units (almost 57% of the 2021 draft GLY emission units) were zeroed out in the 2021 draft inventory. This data suggests that the 2021 draft emissions were only generated by 81 GLY emission units. Therefore, the total count of emitting GLY emission units technically decreased by almost 54%, which caused the observed decrease in the GLY emissions. Table 80 compares the counts of glycol dehydrator units between the 2017 final and 2021 draft inventory years. Furthermore, OCS AQS calculates GLY emissions based on the emission rates provided by the operators, and it cannot validate that these are latest and correct. The users import those EFs, and OCS AQS has no control over their estimation methodologies or values; discrepancies can be expected, depending on the quality of the imported data in the 2021 draft and 2017 final data.

Table 80: Comparison GLY units counts (number) by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Count of GLY Emission Units	176	187	+ 6%
Count of GLY Emission Units – not zeroed out	176	81	- 53.97%

6.5.14 Arsenic

Table 60 shows a considerable increase in the total 2021 draft annual emissions of arsenic. In the 2021 draft inventory, operators reported 0.0041 tons of arsenic emissions, which is 57% higher than the reported emissions in the 2017 final data of 0 0.0026 tons.

6.5.14.1 Arsenic Emissions by Equipment Type

Using the Reports module in OCS AQS, arsenic emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 35. As illustrated, turbines are the highest contributing equipment to the total arsenic emissions in both inventory years. Therefore, the following sections provide a deeper investigation on turbine emission units in the 2021 draft and 2017 final inventories to identify data or calculation-related issues.

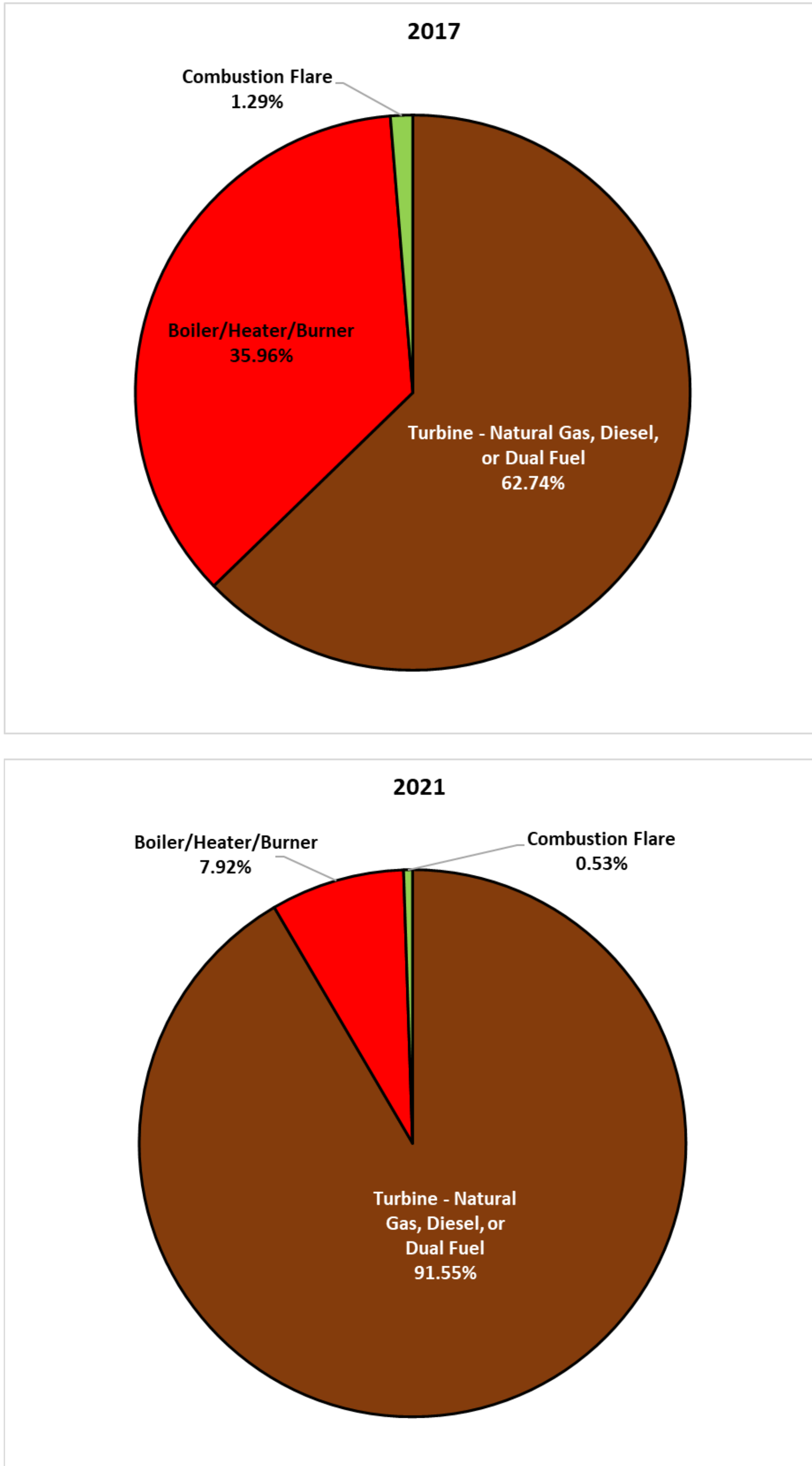


Figure 35: Percentage of arsenic emissions by equipment type for 2017 final and 2021 draft data

6.5.14.2 Increase in Arsenic Emissions – Investigations

6.5.14.2.1 Investigations on Turbines Arsenic Emissions

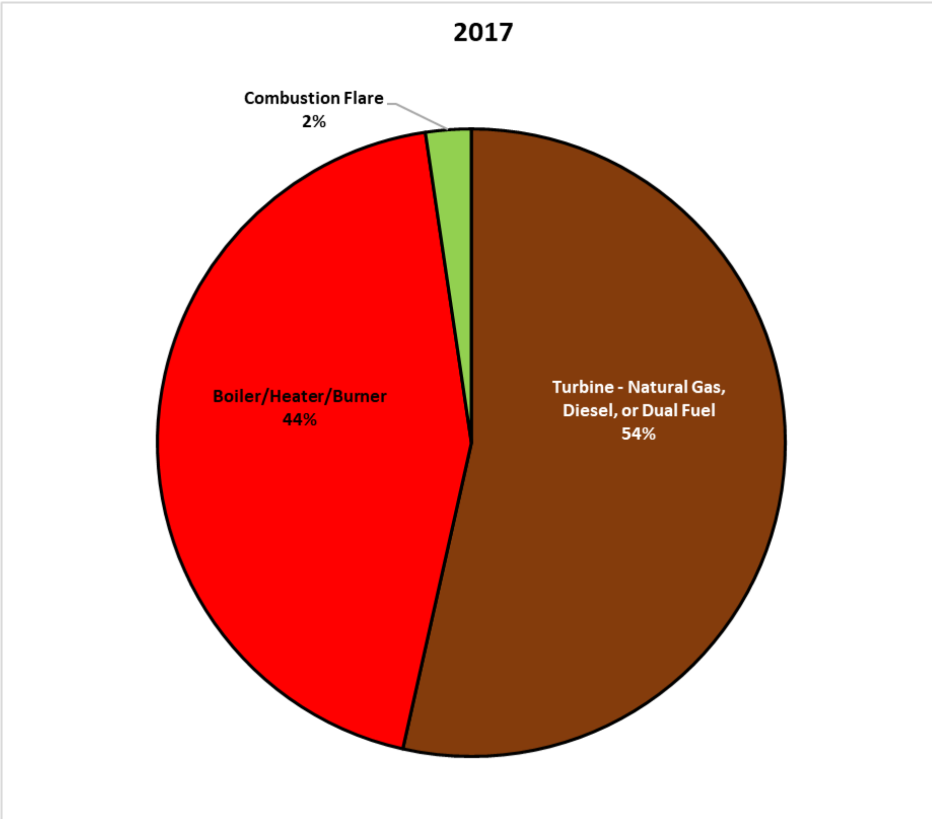
Arsenic is specifically emitted from diesel turbines (NGT-D). Therefore, like Pb (Section 6.5.12.2), the increase in arsenic emissions in the 2021 draft inventory is due to the 44.7% increase of the fuel throughput for diesel turbines during that year. In future inventory efforts, operators will be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data.

6.5.15 Beryllium

Table 60 shows a moderate increase in the total 2021 draft annual emissions of beryllium. In the 2021 draft inventory, operators reported 1.25E-04 tons of beryllium emissions, which is 44.4% higher than the reported emissions in the 2017 final data of 8.65E-05 tons.

6.5.15.1 Beryllium Emissions by Equipment Type

Using the Reports module in OCS AQS, beryllium emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 36. Turbines are the highest contributors to the total beryllium emissions in both inventory years. Therefore, the following sections provide a deeper investigation to identify data- or calculation-related issues.



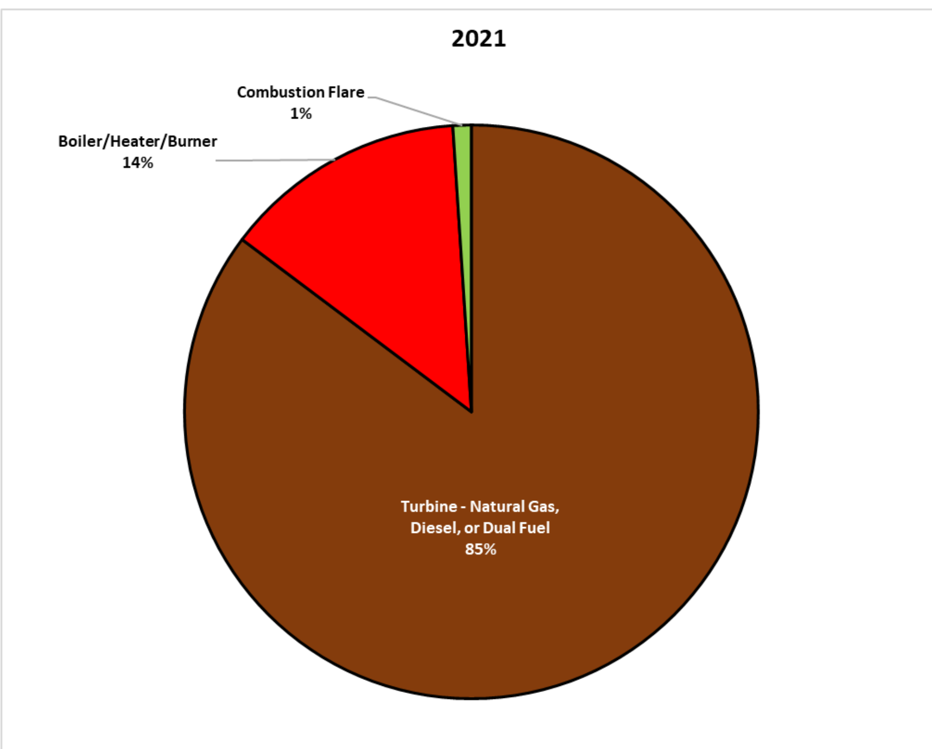


Figure 36: Percentage of beryllium emissions by equipment type for 2017 final and 2021 draft data

6.5.15.2 Increase in Beryllium Emissions – Investigations

6.5.15.2.1 Investigations on Turbines Beryllium Emissions

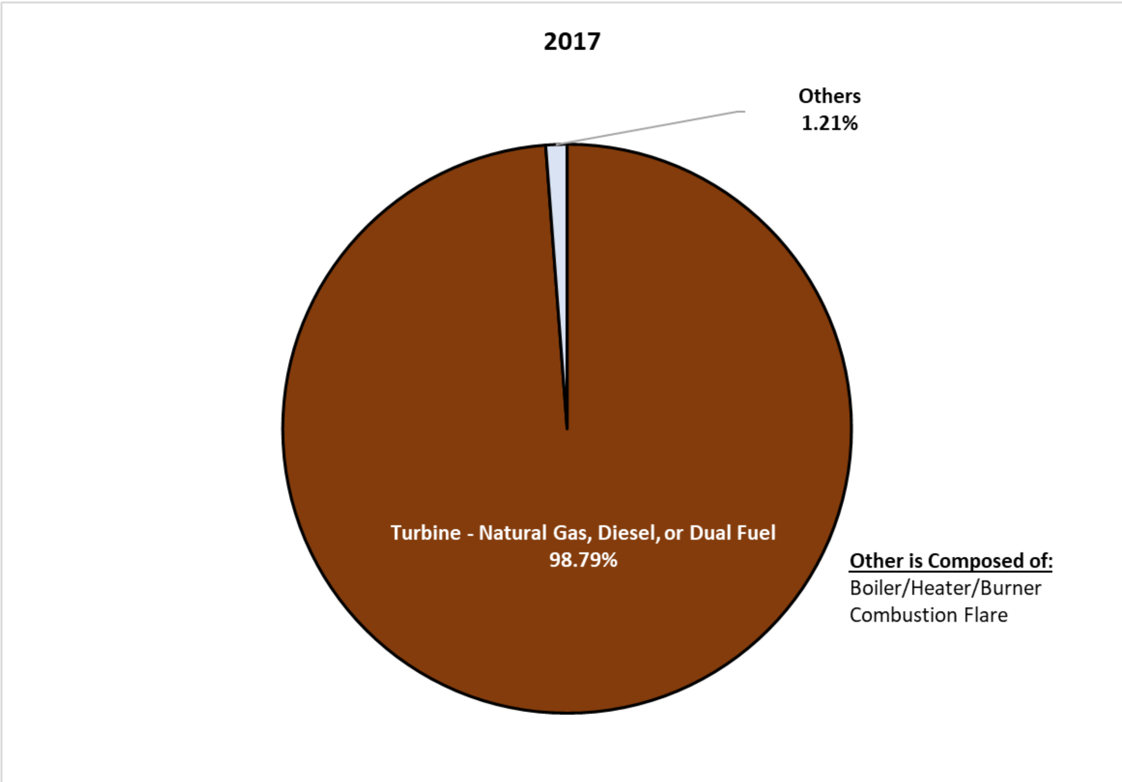
Beryllium is emitted specifically from diesel turbines (NGT-D). Therefore, like Pb (Section 6.5.12.2), increase in beryllium emissions in the 2021 draft inventory is due to the 44.4% increase of the fuel throughput to the diesel turbines during that year. In future inventory efforts, operators will be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data to BOEM.

6.5.16 Chromium (VI)

Table 60 shows a minimal increase in the total 2021 draft annual emissions of chromium (VI). In the 2021 draft inventory, operators reported 0.0206 tons of chromium (VI) emissions, which is 8.4% higher than the reported emissions in the 2017 final data of 0.019 tons.

6.5.16.1 Chromium (VI) Emissions by Equipment Type

Using the Reports module in OCS AQS, chromium (VI) emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 37. Turbines are the highest contributors to the total chromium (VI) emissions in both inventory years. Therefore, the following sections provide a deeper investigation on the turbine emission units to identify data- or calculation-related issues.



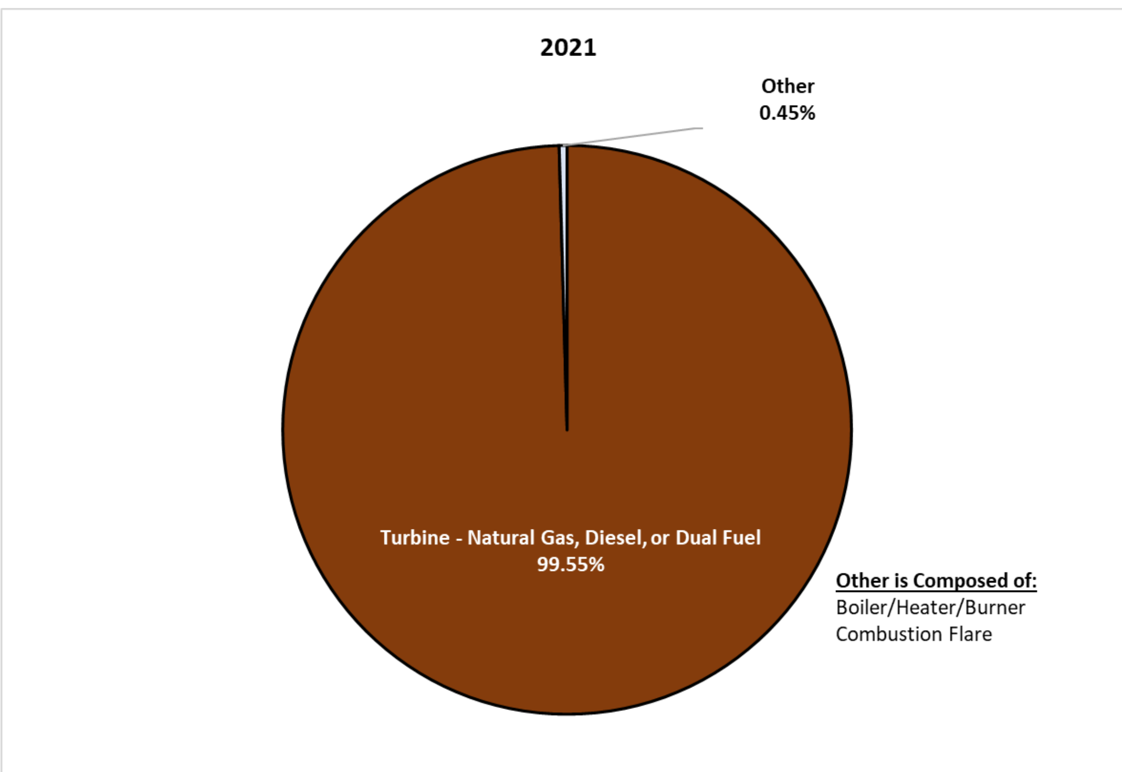


Figure 37: Percentage of chromium (VI) emissions by equipment type for 2017 final and 2021 draft data

6.5.16.2 Increase in Chromium (VI) Emissions – Investigations

6.5.16.2.1 Investigations on Turbines Chromium (VI) Emissions

Chromium (VI) is emitted from both NGT and diesel turbines (NGT-D). Throughputs to both processes are compared in Table 81. Chromium (VI) emissions increased in 2021 draft data as compared to 2017 final data because NGT throughputs and NGR-D count and throughputs increased.

Table 81: Comparison of NGT throughputs by inventory year with % change

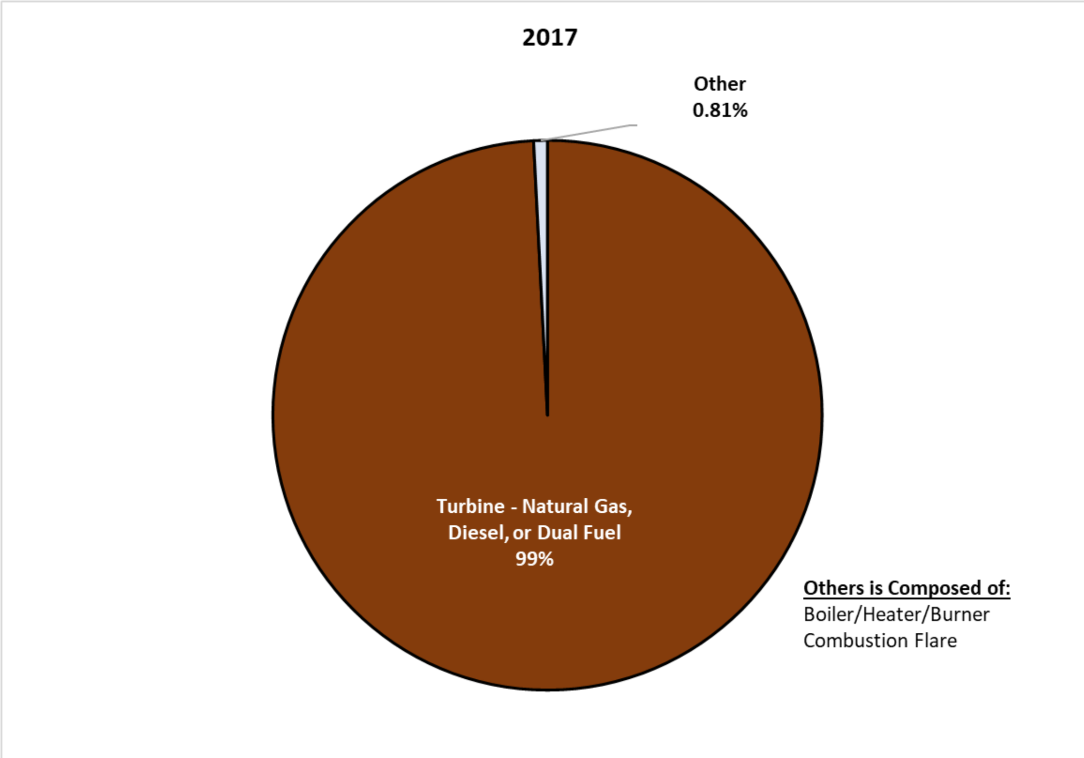
Parameter	2017 Final	2021 Draft	% Change
Number of NGT Processes Reported in the Inventory	350	399	+ 14.00%
Number of **Active Emitting** NGT Processes	350 of 350	336 of 399	- 4.00%
Total Fuel Usage by Active Emitting Processes [Mscf]	58,631,713.19	60,321,144.52	+ 2.88%
Number of NGT-D Processes Reported in the Inventory	57	111	+ 94.74%
Number of **Active Emitting** NGT-D Processes	57 of 57	89 of 111	+ 56.14%
Total Fuel Usage by Active Emitting NGT-D Processes [Gallons]	3,468,139.36	5,017,722.15	+ 44.68%

6.5.17 Chromium (III)

Table 60 shows a minimal increase in the total 2021 draft annual emissions of chromium (III). In the 2021 draft inventory, operators reported 0.4817 tons of chromium (III) emissions, which is 7.5% higher than the reported emissions in the 2017 final data of 0.4479 tons.

6.5.17.1 Chromium (III) Emissions by Equipment Type

Using the Reports module in OCS AQS, chromium (III) emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 38. Turbines are the highest contributors to the total chromium (III) emissions in both inventory years. Therefore, the following sections provide a deeper investigation on turbine emission units to identify data- or calculation-related issues.



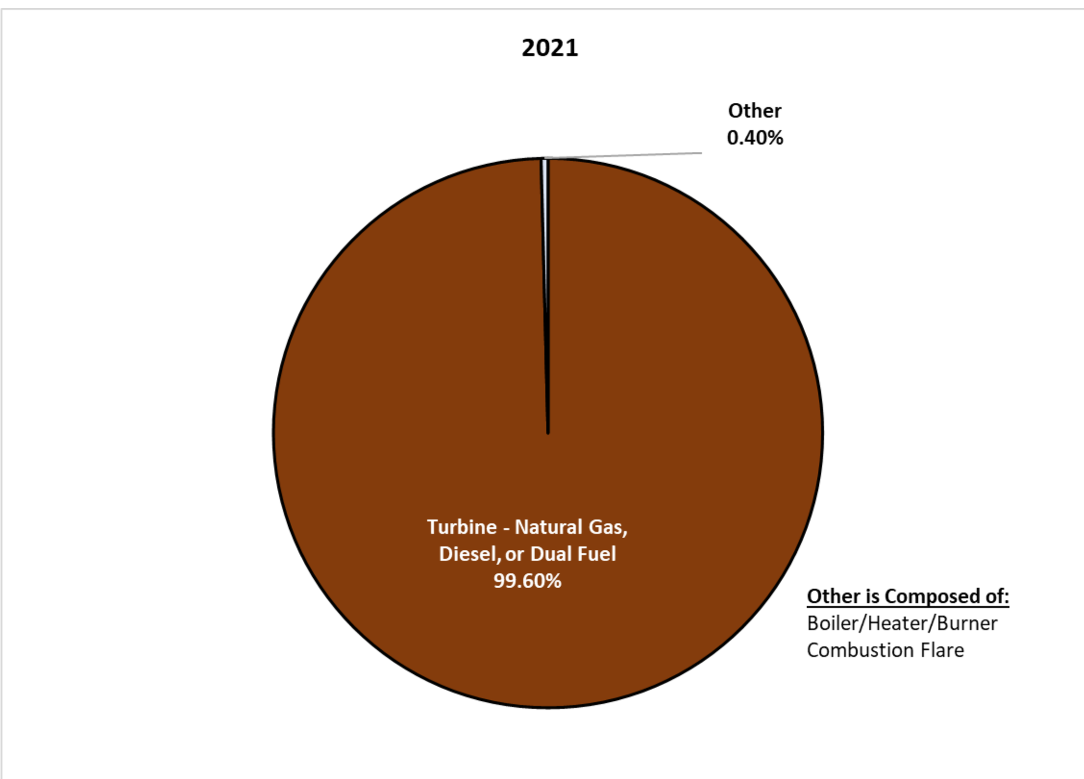


Figure 38: Percentage of chromium (III) emissions by equipment type for 2017 final and 2021 draft data

6.5.17.2 Increase in Chromium (III) Emissions – Investigations

6.5.17.2.1 Investigations on Turbines Chromium (III) Emissions

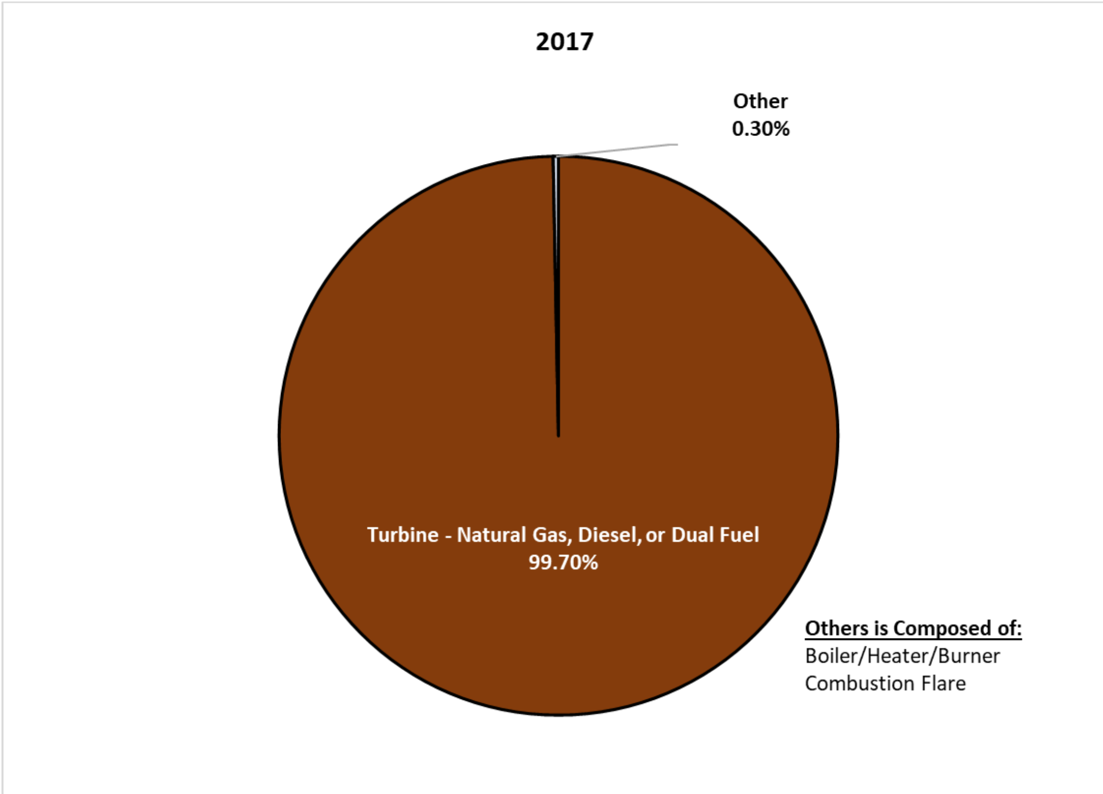
Chromium (III) is emitted from both NGT and diesel turbines (NGT-D). Therefore, like chromium (VI), chromium (III) emissions increased slightly in the 2021 draft data because of the increase in the count of NGT-D in the 2021 draft inventory, which caused an increase in the total fuel usage by NGT-D.

6.5.18 Mercury

Table 60 shows a minimal increase in the total 2021 draft annual emissions of mercury. In the 2021 draft inventory, operators reported 0.2477 tons of mercury emissions, which is 7.2% higher than the reported emissions in the 2017 final data of 0.2309 tons.

6.5.18.1 Mercury Emissions by Equipment Type

Using the Reports module in OCS AQS, mercury emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 39. As illustrated, turbines are the highest contributors to the total mercury emissions in both inventory years. Therefore, the following sections provide a deeper investigation on turbine emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.



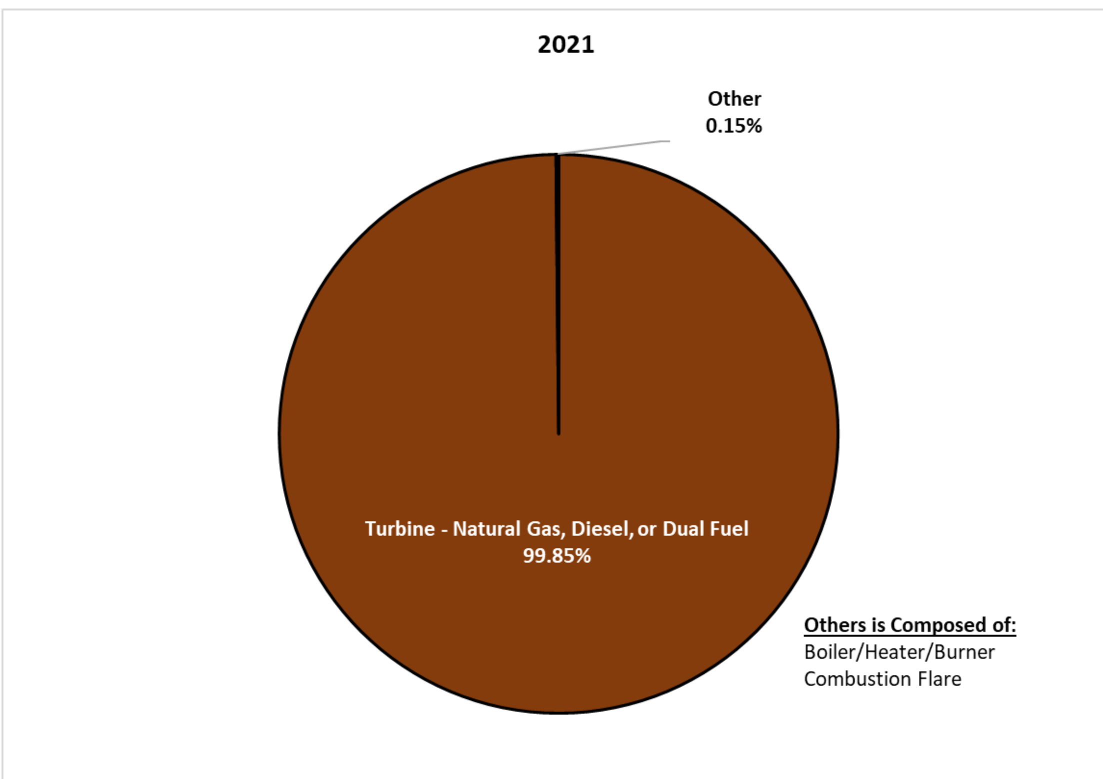


Figure 39: Percentage of mercury emissions by equipment type for 2017 final and 2021 draft data

6.5.18.2 Increase in Mercury Emissions – Investigations

6.5.18.2.1 Investigations on Turbines Mercury Emissions

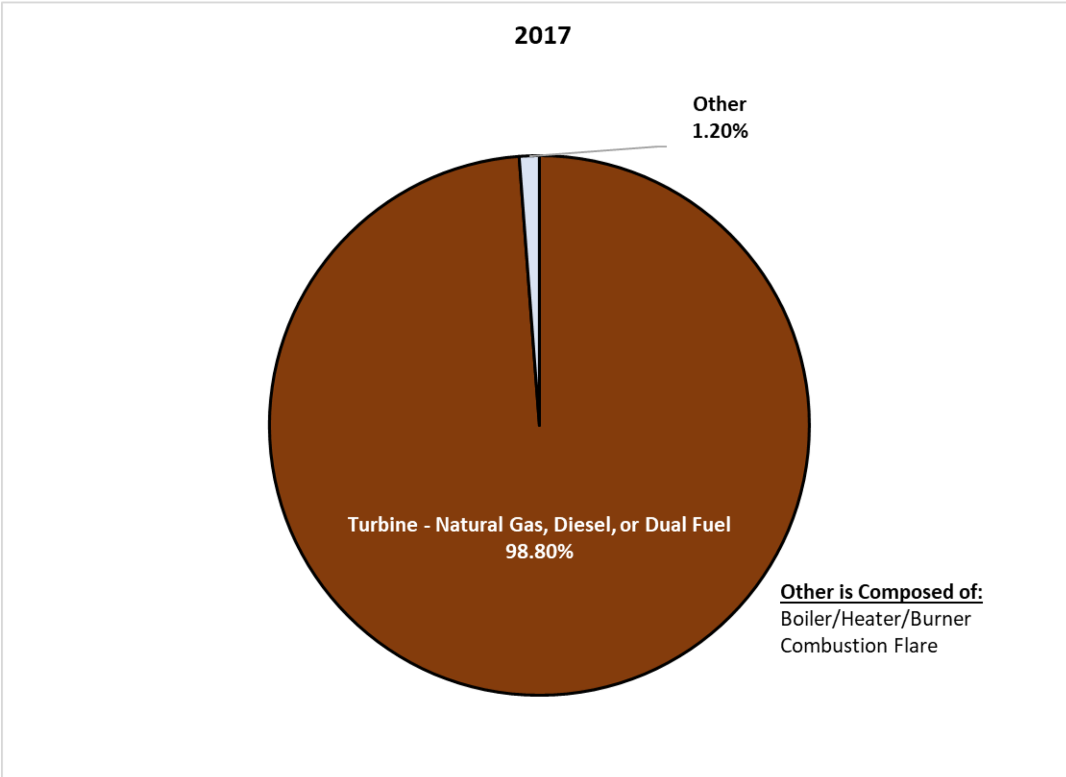
Mercury is emitted by both NGT and diesel turbines (NGT-D). Throughputs to both processes are compared in Table 81. Throughputs to both turbine types increased (and counts in the NGT-D) in 2021 draft data and accounts for the increase in the 2021 draft emissions of mercury.

6.5.19 Cadmium

Table 60 shows a minimal increase in the total 2021 draft annual emissions of cadmium. In the 2021 draft inventory, operators reported 0.2613 tons of cadmium emissions, which is 7.056% higher than the reported emissions in the 2017 final data of 0.2441 tons.

6.5.19.1 Cadmium Emissions by Equipment Type

Using the Reports module in OCS AQS, cadmium emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 40. As illustrated, turbines are the highest contributors to the total cadmium emissions in both inventory years. Therefore, the following sections provide a deeper investigation on turbine emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.



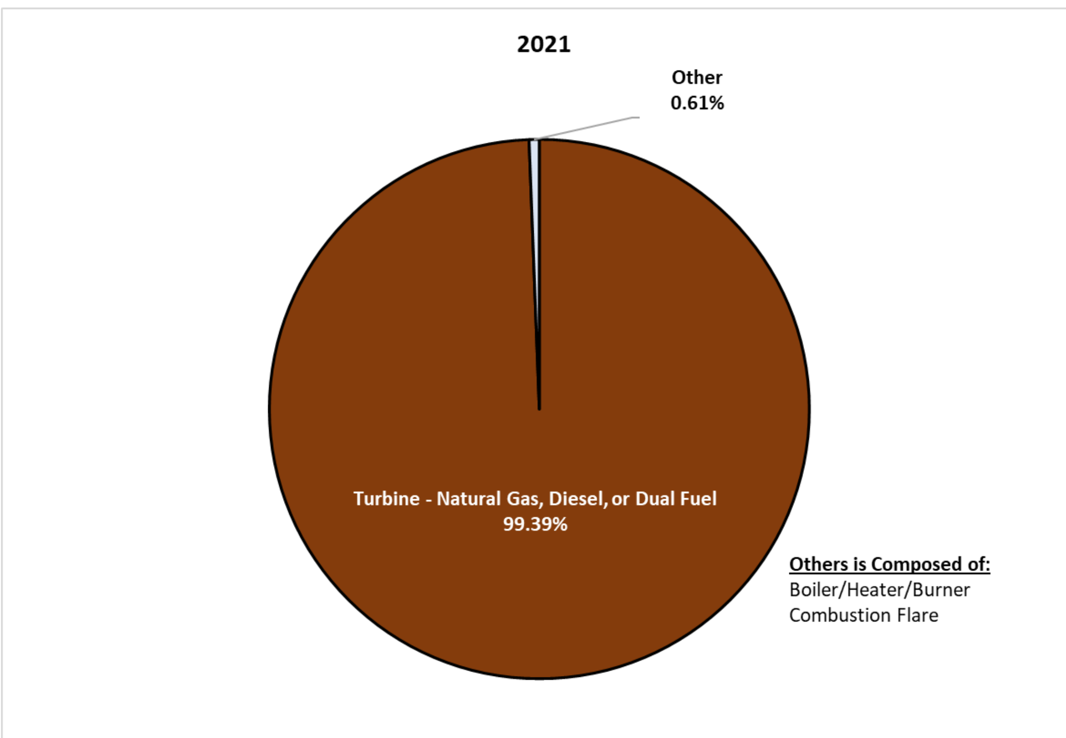


Figure 40: Percentage of cadmium emissions by equipment type for 2017 final and 2021 draft data

6.5.19.2 Increase in Cadmium Emissions – Investigations

6.5.19.2.1 Investigations on Turbines Cadmium Emissions

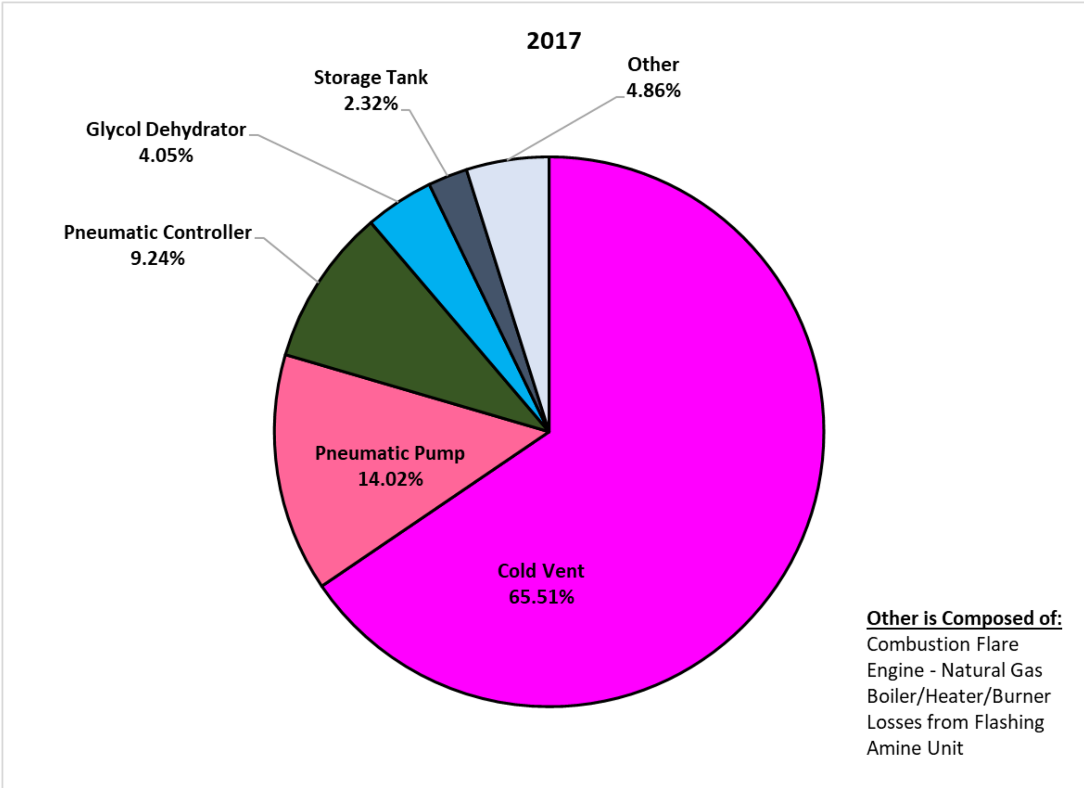
Cadmium is emitted from both NGT and diesel turbines (NGT-D). Throughputs to both processes are compared in Table 81. Throughputs to both types of these turbines (and count of the NGT-D) increased in 2021 draft data and accounts for the increase in the 2021 draft emissions of cadmium.

6.5.20 Hexane

Table 60 shows a moderate decrease in the total 2021 draft annual emissions of hexane. In the 2021 draft inventory, operators reported 617.415 tons of hexane emissions, which is 19.34% lower than the reported emissions in the 2017 final data of 765.512 tons.

6.5.20.1 Hexane Emissions by Equipment Type

Using the Reports module in OCS AQS, hexane emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 41. As illustrated, cold vents are the highest contributors to the total hexane emissions in both inventory years. Therefore, the following sections provide a deeper investigation of the cold vent emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.



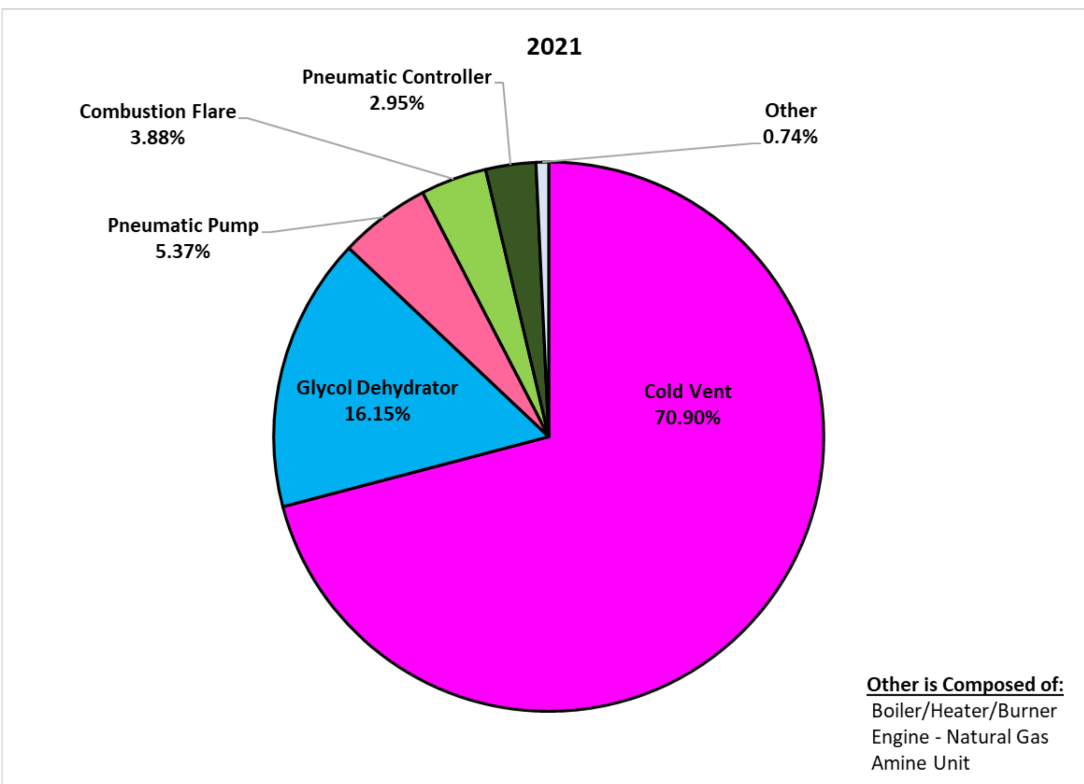


Figure 41: Percentage of hexane emissions by equipment type for 2017 final and 2021 draft data

6.5.20.2 Decrease in Hexane Emissions – Investigations

6.5.20.2.1 Investigations on Cold Vents Hexane Emissions

Hexane emissions are calculated from VOC emissions as shown below (Wilson et al. 2019):

$$E_{VOC} = C_{VOC} \times 10^{-6} \times \frac{m_{VOC} \times V \times 1{,}000}{379.4 \frac{scf}{lb \cdot mol}} \qquad (Eq. 85)$$

$$E_{Hexane} = E_{VOC} \times \frac{0.35195}{17.21} \qquad (Eq. 86)$$

The above equations indicate that the calculated hexane emissions are directly proportional to VOC emissions that are, in turn, proportional to the concentration of VOC in the vent gas (C_{VOC}), the molecular weight of VOC (m_{VOC}) (which is calculated by normalizing the VOC compositions of the sales gas data), and the volume of gas vented from miscellaneous sources (V).

Therefore, we investigated further the data provided for the volume of gas vented and the facilities' sales gas compositions in the following sections.

> ***NOTE:*** It is necessary to mention that the submitted concentrations of VOC in the vent gas can also have a significant impact on the VOC calculated emissions. A more comprehensive analysis of this parameter (Section 6.6.4.2) showed that some instances of anomalous concentrations of VOC in the vented gas values caused a substantial increase in the VOC cold vents emissions, which also increased the hexane emissions. Corrective actions for those high values were requested to address this issue and are reflected in Section 6.6.4.2.

6.5.20.2.2 Investigations on Volume of Vented Gas

As previously demonstrated in the discussion about CH_4 emissions (Section 6.5.2), the total annual volume of vented gas decreased by 38.2%. This decrease can be considered a significant contributing factor to the decrease of hexane emissions in the 2021 draft inventory.

6.5.20.2.3 Investigations on Sales Gas Data

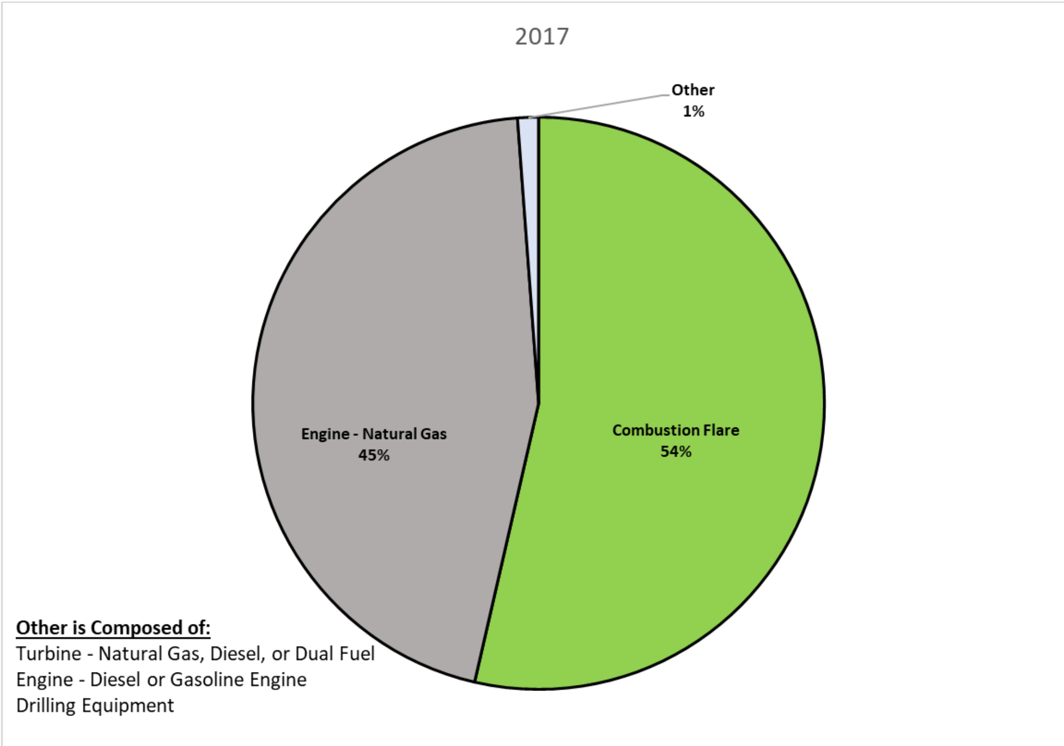
As stated above, 48 facilities did not provide sales gas compositions (Section 6.5.2.2.2). However, those facilities did not have cold vents in their submitted inventories; therefore, the unreported sales gas composition did not affect their emissions. The 48 facilities with unsubmitted sales gas did not contribute to the decrease in the hexane emissions in the 2021 draft inventory and it can be concluded that the 19% decrease in hexane emissions in the 2021 draft data was due to the 38.2% reduction in the combined values specified for the volume of vented gas parameter of the cold vent emission units. In future inventory efforts, operators will be able to analyze their activity data (in this case, volume of vented gas) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error and need correction before operators submit emissions data to BOEM.

6.5.21 Acetaldehyde

Table 60 shows a moderate increase in the total 2021 draft annual emissions of acetaldehyde. In the 2021 draft inventory, operators reported 213.211 tons of acetaldehyde emissions, which is 37.56% higher than the reported emissions in the 2017 final data of 155.005 tons.

6.5.21.1 Acetaldehyde Emissions by Equipment Type

Using the Reports module in OCS AQS, acetaldehyde emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 42. As illustrated, combustion flares were the highest contributors to the total emissions in both inventory years. Therefore, the following sections provide a deeper investigation of the combustion flare emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.



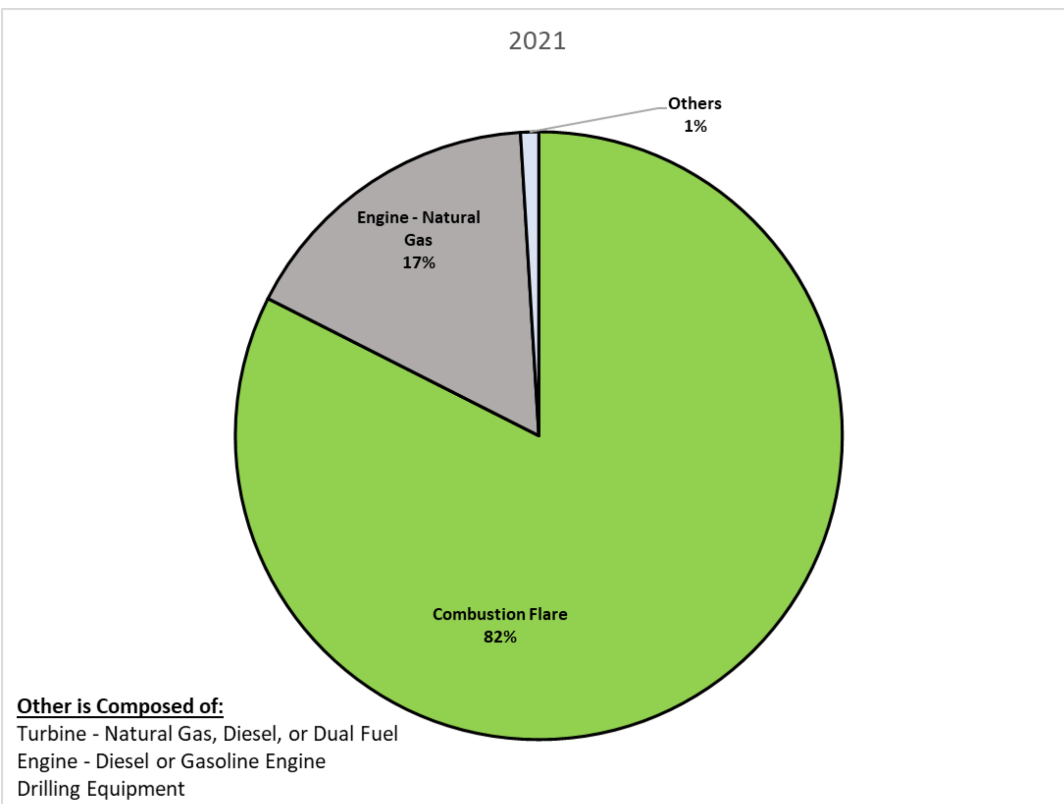


Figure 42: Percentage of acetaldehyde emissions by equipment type for 2017 final and 2021 draft data

6.5.21.2 Increase in Acetaldehyde Emissions – Investigations

6.5.21.2.1 Investigations on Combustion Flare Acetaldehyde Emissions

Acetaldehyde emissions from combustion flares are calculated using the following equation (Wilson et al. 2019):

$$E_{\text{Acetaldehyde}} = V \times H \times EF_{\text{Acetaldehyde}} \times 0.001 \qquad (Eq. 87)$$

The above equation indicates that the calculated emissions are directly proportional to the total volume of gas flared (V) in Mscf, flare gas heating value (H) in (Btu/scf), and the EF ($EF_{\text{Acetaldehyde}}$) in lb/MMBtu. Therefore, these three factors are possible causes for the increase in acetaldehyde emissions.

The combustion flare acetaldehyde EF is the same in both inventories, and the possibility that it contributes to the increase in the acetaldehyde emissions is disregarded. Therefore, the following section focus on the total volume of gas flared (V) as the potential contributing factor. Flare gas heating value (H) can also significantly impact the combustion flares emissions. This parameter is comprehensively analyzed later in the combustion flares section (Section 6.6.4.1).

6.5.21.2.2 Investigations on Volume of Gas Flared

Table 82 shows that the overall volume of gas flared (including both main flare and pilot) increased by 3.41% in the 2021 draft inventory year. Acetaldehyde is not calculated for the pilot; therefore, the comparison presented in Table 82 would be more informative if it was explicitly for combustions flare–flaring process throughputs (not including pilot). However, the direct comparison is not achievable in this inventory year; the 2017 final data combined both flaring and pilot throughputs, and there was no way for the Team to determine flaring throughput only. In future cycles, this analysis can be performed because the pilot and flaring processes are now separate, and operators are required to report their throughputs for each.

After analysis, it can be assumed that the increase in the total volume of gas flared is one of the contributing factors to the increase in the acetaldehyde emissions in the 2021 draft inventory. When the flare emissions were analyzed in detail in Section 6.6.4.1, flaring gas heating values were substantially lower than expected for some flare emission units, causing a decrease in the overall flaring processes emissions. The Team addressed this issue by contacting those facilities and requesting corrections, which made the 2021 final acetaldehyde emissions equal to 248.502 tons (Section 8.1).

> ***NOTE:*** The total volume of gas flared (including both flaring and pilot) in Table 82 is the corrected throughput after including the corrective action on the anomaly pilot throughput that was detected in Section 6.5.1.1.1. As previously stated, this is the only corrective action that was included in the 2021 draft inventory. All subsequent corrective actions are included in the revised 2021 inventory to prevent the abnormally high throughput value from obscuring other possible anomalies.

Table 82: Comparison of combustion flares throughputs and equipment counts by inventory year with % change (post-corrective action)

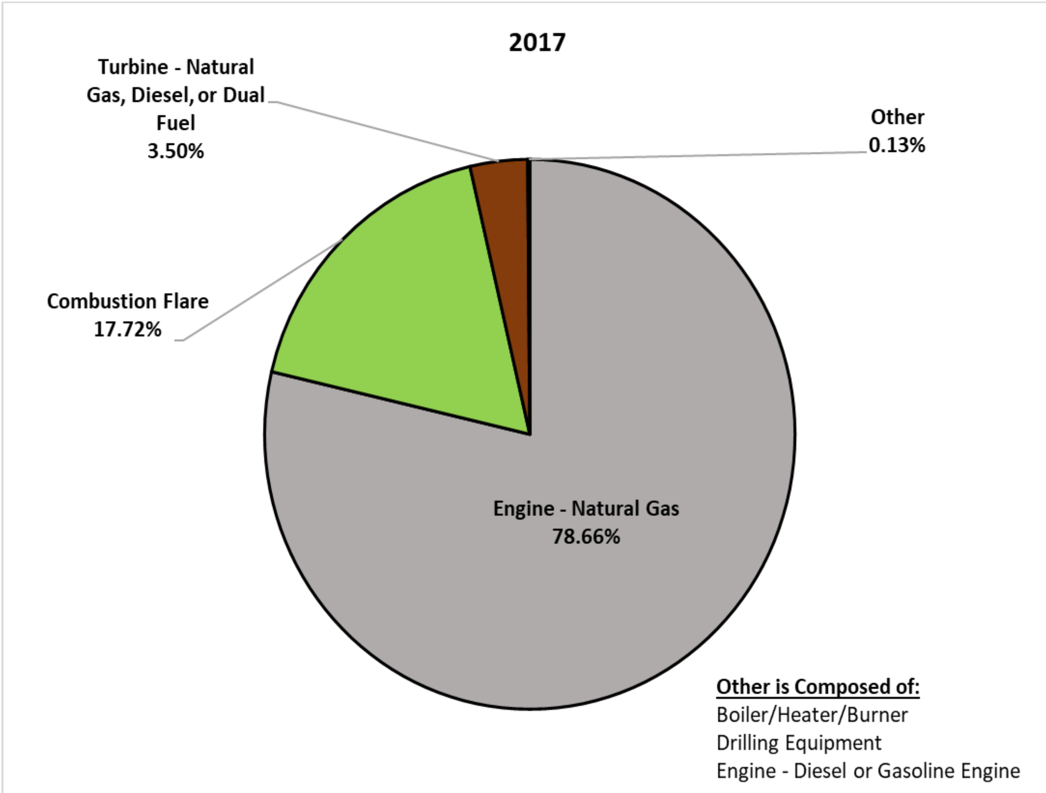
Parameter	2017 Final	2021 Draft	% Change
Number of Combustion Flare Emissions Units Reported in the Inventory	90	114	+ 26.67%
Number of **Active Emitting** Flares Emission Units	90 of 90	100 of 114	+ 11.11%
Total Volume of Gas Flared (including both flaring and pilot) [Mscf]	6,264,700	6,478,161	+ 3.41%

6.5.22 Formaldehyde

Table 60 shows a moderate decrease in the total 2021 draft annual emissions of formaldehyde. In the 2021 draft inventory, operators reported 542.427 tons of formaldehyde emissions, which is 23.078% lower than the reported emissions in the 2017 final data of 705.165 tons.

6.5.22.1 Formaldehyde Emissions by Equipment Type

Using the Reports module in OCS AQS, formaldehyde emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 43. As illustrated, NGE were the highest contributors to the total emissions in the 2017 final inventory year. However, the flares contribution to the 2021 draft emissions increased and made NGE the second highest contributor in the 2021 draft inventory. Therefore, the following sections provide a deeper investigation of the combustion flare and NGE emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.



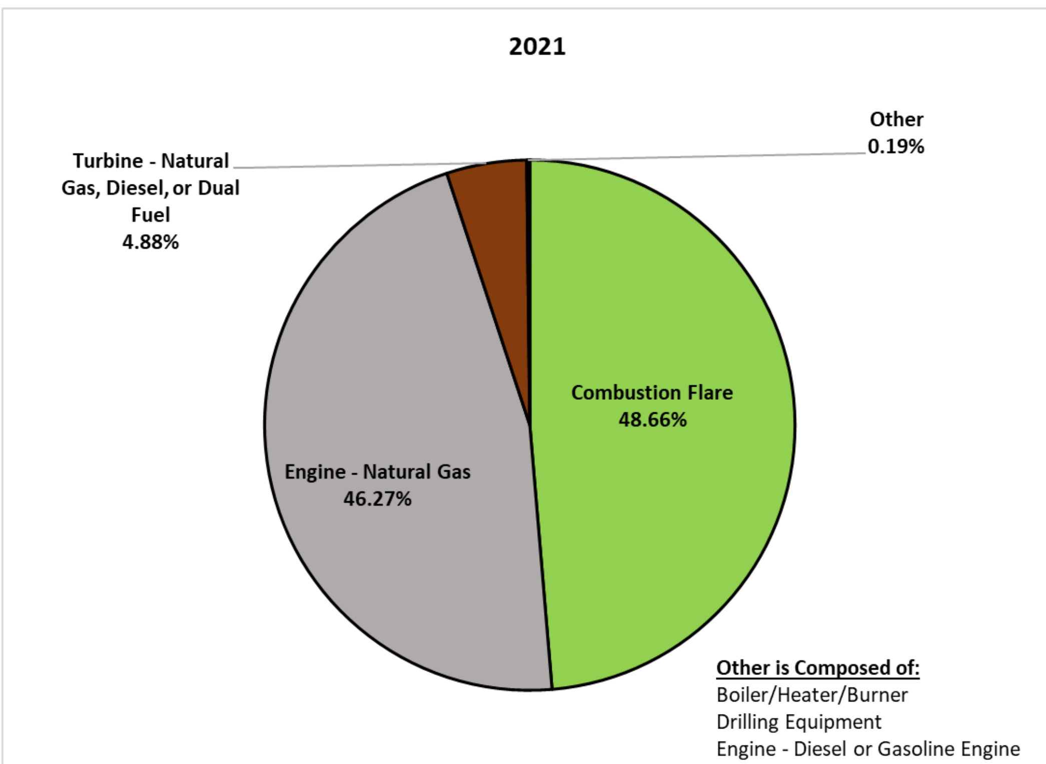


Figure 43: Percentage of formaldehyde emissions by equipment type for the 2017 final and 2021 draft data

6.5.22.2 Decrease in Formaldehyde Emissions – Investigations

The discussion on acetaldehyde emissions (Section 6.5.21.2.2) showed an increase in the volume of gas flared, which would proportionally increase flare emissions and have a strong impact on formaldehyde emissions. However, the increase seems to have been compensated for by the decrease in the formaldehyde emissions from NGE, resulting in an overall decrease in the total 2021 draft formaldehyde emissions. In other words, the decrease in formaldehyde emissions from NGE masked the increase in formaldehyde emissions from combustion flares and caused a decrease in the total formaldehyde emissions in the 2021 draft inventory.

Therefore, in the following section, the conducted investigations were focused on NGE emission units.

6.5.22.2.1 Investigations on NGE Formaldehyde Emissions

Formaldehyde emissions from NGE are calculated using the following equation (Wilson et al. 2019):

$$E_{\text{Formaldehyde}} = EF_{\text{Formaldehyde}} \times H \times U \times 0.001 \qquad (Eq. 88)$$

The above equation indicates that the calculated emissions are directly proportional to fuel usage (U), formaldehyde EF ($EF_{\text{Formaldehyde}}$), and fuel heating value (H), making these variables possible causes for the decrease in formaldehyde emissions. The NGE formaldehyde EF is the same for both inventories and therefore would not contribute to the decrease in the formaldehyde emissions. Therefore, the investigation in the following section focuses on fuel usage (U).

> ***NOTE:*** Fuel heating value (H) can also significantly impact NGE emissions. This parameter was comprehensively analyzed in the Section 4.6.2.3 (Data Range Checks).

6.5.22.2.2 Investigations of Natural Gas Throughputs

Although the count of NGE processes reported in the 2021 draft emissions inventory increased by 4.17%, only 708 of 1,199 NGE processes were actively emitting (Table 83); the remaining NGE belonged to non-operating facilities or were reported as zero emissions processes. The count of emitting NGE processes decreased 38.49%, resulting in a 54.73% decrease in annual fuel usage by emitting processes. NGE contributed almost 79% to the total 2017 final emissions of formaldehyde, and the 54.73% decrease in the throughput to those engines resulted in the observed 23% decrease in total formaldehyde emissions in the 2021 draft data.

Table 83: Comparison of NGE throughputs and equipment counts by inventory year with % change

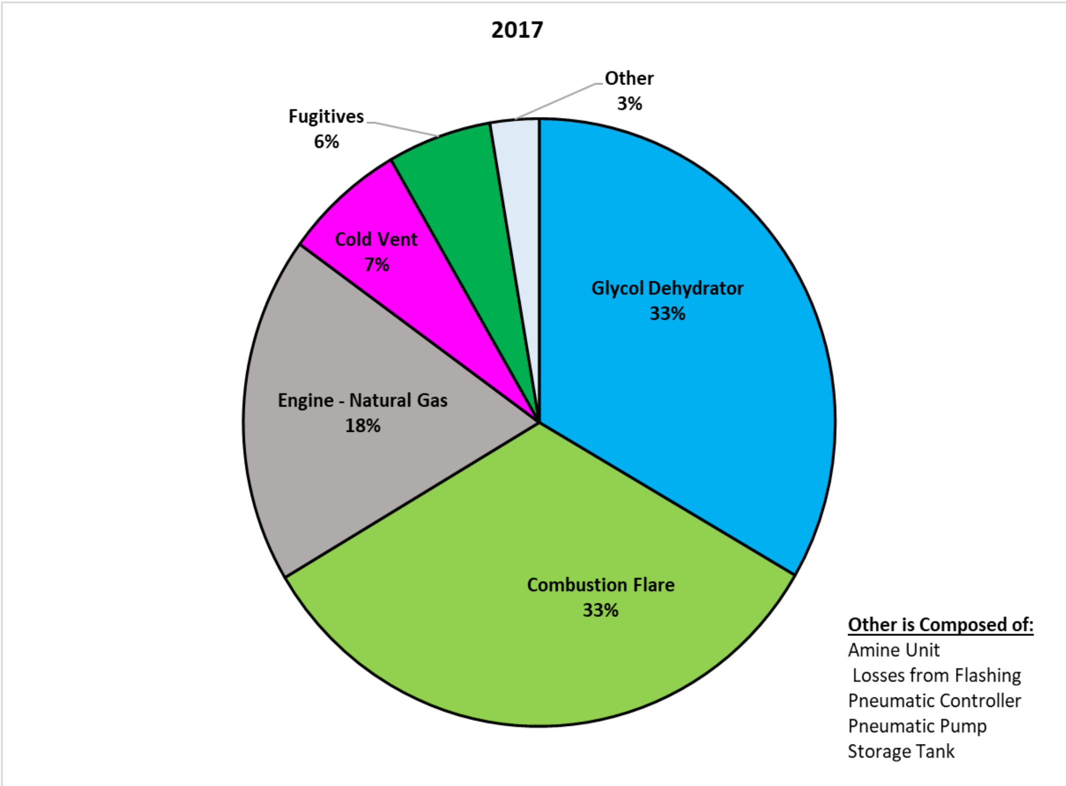
Parameter	2017 Final	2021 Draft	% Change
Number of NGE Processes	1,151	1,199	+ 4.17%
Number of Active Emitting Natural Gas Processes	1,151 of 1,151	708 of 1,199	- 38.49%
Throughput to NGE Processes [Mscf]	33,872,765	15,396,908	- 54.54%

6.5.23 2,2,4-Trimethylpentane

Table 60 shows a minimal decrease in the total 2021 draft annual emissions of 2,2,4-trimethylpentane. In the 2021 draft inventory, operators reported 8.517 tons of 2,2,4-trimethylpentane emissions, which is 11.45% lower than the reported emissions in the 2017 final data of 9.619 tons.

6.5.23.1 2,2,4-Trimethylpentane Emissions by Equipment Type

Using the Reports module in OCS AQS, 2,2,4-trimethylpentane emissions for both the 2017 final and 2021 draft inventories were exported into MS Excel and used to generate Figure 44. As illustrated, glycol dehydrators and combustion flares contributed equally to the total emissions in the 2017 final inventory. However, the glycol dehydrators' contribution to the 2021 draft emissions decreased substantially and made the cold vents the second highest contributing equipment in the 2021 draft inventory. Additionally, fugitive and storage contribution to the 2,2,4-trimethylpentane emissions was completely absent in the 2021 draft data. Therefore, the following sections provide a deeper investigation of the glycol dehydrators, fugitives, and storage tanks emission units in the 2017 final and 2021 draft inventories to identify data- or calculation-related issues.



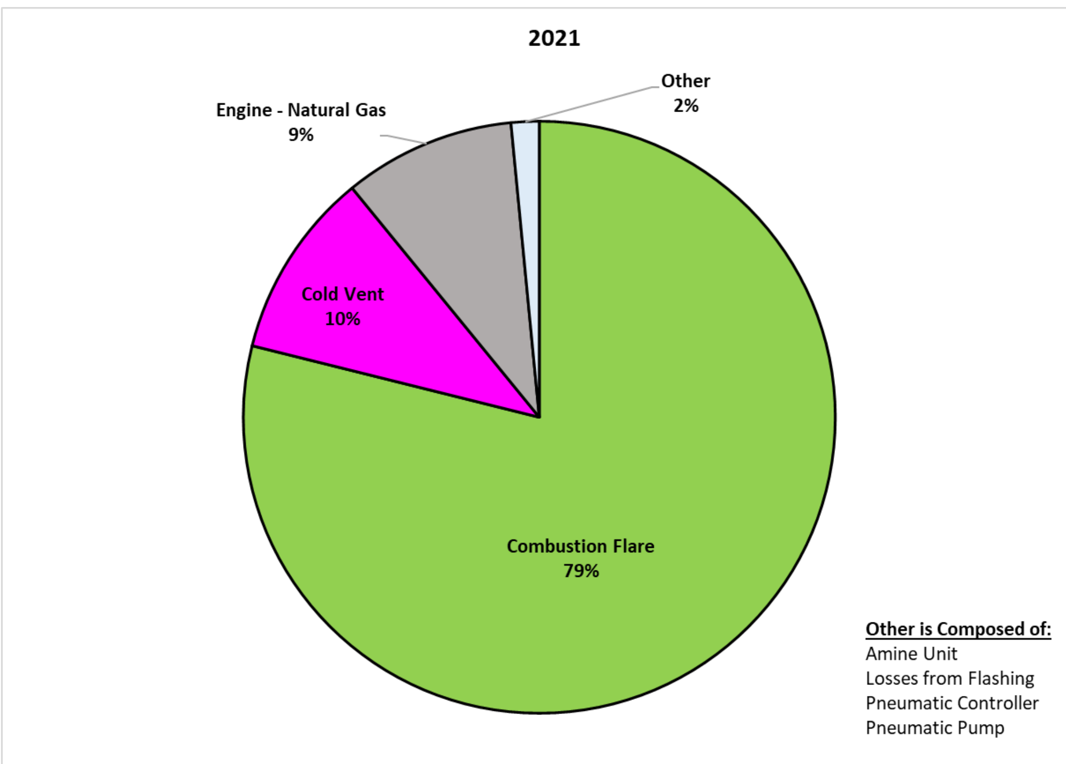


Figure 44: Percentage of 2,2,4-trimethylpentane emissions by equipment type for 2017 final and 2021 draft data

6.5.23.2 Decrease in 2,2,4-Trimethylpentane Emissions – Investigations

The discussion on acetaldehyde emissions (Section 6.5.21.2.2) shows that the volume of gas flared increased, which would proportionally increase flare emissions for all pollutants emitted. This increase in volume of gas flared also increases 2,2,4-trimethylpentane emissions and made the combustion flares the highest contributor to the 2021 draft 2,2,4-trimethylpentane emissions. However, this increase seems to have been compensated for by the substantial decrease of the 2,2,4-trimethylpentane emissions from glycol dehydrators and the complete absence of 2,2,4-trimethylpentane emissions from fugitives, which resulted in an overall decrease in the total 2021 draft 2,2,4-trimethylpentane emissions. In other words, the decrease in 2,2,4-trimethylpentane emissions from glycol dehydrators and fugitives might have masked the increase in 2,2,4-trimethylpentane emissions from combustion flares and caused a decrease in the total 2,2,4-trimethylpentane emissions in the 2021 draft inventory. Therefore, the investigations detailed in the following sections focus on glycol dehydrators, storage tanks, and fugitive emission units.

6.5.23.2.1 Investigations on Glycol Dehydrators 2,2,4-Trimethylpentane Emissions

Emissions contributions by glycol (GLY) units were previously discussed in detail in Section 6.5.13.2.1. Table 80 shows that the number of active glycol emission units decreased by 54% between the 2017 final and 2021 draft inventories, which led to the observed decrease in the 2,2,4-thrimethylpentane GLY emissions.

6.5.23.2.2 Investigations on Fugitives 2,2,4-Trimethylpentane Emissions

The 2021 draft inventory counted 2,2,4-trimethylpentane emissions from fugitives under VOC emissions, whereas in the 2017 final inventory, the volatile HAP speciation profile was used to estimate the amounts of 2,2,4-trimethylpentane in the fugitives' VOCs. Therefore, 2,2,4-trimethylpentane emissions are absent from 2021 draft fugitives' emission units, causing the observed emissions discrepancy. Nevertheless, investigations conducted explicitly on fugitives (Section 6.6.5.2) analyze the VOC emissions from fugitives in both inventory years and identify any data entry issues that impacted VOC emissions and, ultimately, 2,2,4-trimethylpentane emissions. Therefore, no further investigations are conducted in this section.

6.6 Platform Emissions by Equipment Type

Sections 4.6 and 6.4 focus on the analysis of total emissions by pollutants on the inventory level, aggregated by all equipment types, to identify the discrepancies in emissions between the 2017 final and 2021 draft inventories. Categorizing emissions by pollutants revealed significant anomalies in data for some emission units and specific equipment types, but this general categorization would not detect the less noticeable discrepancies at the equipment type level. This section presents a comprehensive analysis of emissions aggregated by equipment type and allows for a drill-down investigation to discover any anomalies at specific emission units in the inventory.

Platform emissions were estimated for 16 different types of equipment listed in Table 84. The count of total emission units under each distinct equipment type is expected to vary from year to year depending on the platform's activities. Table 84 compares the count of the units under each equipment category in the 2017 final and 2021 draft data. As illustrated, the overall count of emission units increased by 11% in the 2021 draft data. All equipment type counts increased in the 2021 inventory except for pneumatic controllers and storage tanks. Figure 45 shows the trends in equipment counts in the 2021 draft and 2017 final data.

Table 84: Equipment count (number) by inventory year with % change

Type	Description	2017 Final	2021 Draft	Difference	Percentage Change[a]
AMI	Amine Unit	4	4	0	0%
BOI	Boiler/Heater/Burner	403	429	+ 26	+ 6%
DIE	Engine – Diesel or Gasoline Engine	2,144	2,442	+ 298	+ 14%
DRI	Drilling Equipment	12	15	+ 3	+ 25%
FLA	Combustion Flare	90	114	+ 24	+ 27%
FUG	Fugitives	3,199	3,618	+ 419	+ 13%
GLY	Glycol Dehydrator	176	187	+ 11	+ 6%
LOA	Loading Operation	1	1	0	0%
LOS	Losses from Flashing	400	405	+ 5	+ 1.25%
MUD	Mud Degassing	7	16	+ 9	+ 129%
NGE	Engine – Natural Gas	1,151	1,199	+ 48	+ 4%
NGT	Turbine – Natural Gas, Diesel, or Dual Fuel	359	437	+ 78	+ 22%
PNE	Pneumatic Pump	2,757	3,265	+ 508	+ 18%
PRE	Pneumatic Controller	1,703	1,619	- 84	- 5%
STO	Storage Tank	336	298	- 38	- 11%
VEN	Cold Vent	540	666	126	+ 23%
-	**Total Equipment Count**	**13,282**	**14,715**	**1,433**	**+ 11%**

Notes: [a] $Percentage\ Change = \frac{\text{draft 2021 equipment Count} - \text{final 2017 equipment count}}{\text{final 2017 equipment count}} \times 100\%$

> ***NOTE:*** 2021 draft equipment count includes all equipment reported in the 2021 draft inventory. In some instances, the actual count of emitting pieces of equipment can be less than the reported because of zeroed-out processes or because some of the pieces of equipment are under non-operational platforms. When needed, the count breakdown will be provided in the following sections.

> ***NOTE:*** The equipment counts in Table 84 represent the number of pieces of equipment, not the number of the processes associated with them; if a piece of equipment has two processes linked to it, it is still counted as one.

An increase in the total number of emission units does not necessarily correspond to an increase in the 2021 draft emissions. This difference may be due to other factors, such as throughputs and operating hours. The following sections present an overview of the 2021 draft GHG and criteria emissions by equipment types and, subsequently, a detailed review and analysis of the emissions from each equipment type as compared to the 2017 final emissions to evaluate the quality and accuracy of activity data provided in the 2021 draft data.

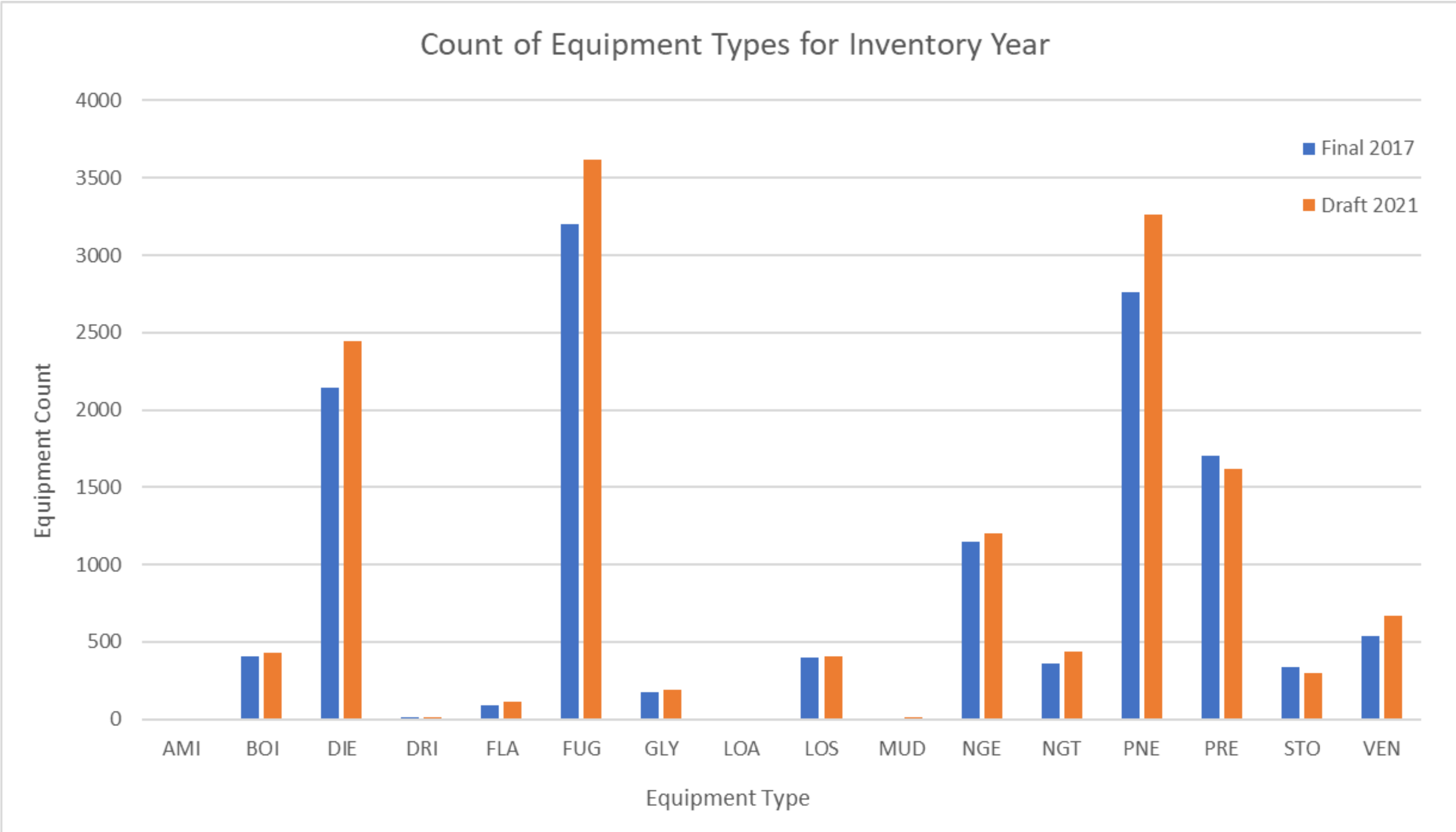


Figure 45: Count of equipment types by inventory year for the 2017 final (blue, left columns) and 2021 draft (orange, right columns) data
See Table 84 for equipment type abbreviations key.

6.6.1 GHG Emissions by Equipment Type

Table 85 summarizes GHG emissions by all equipment types in the 2021 draft data, with bold numbers indicating highest source contributions per pollutant. GHG emissions include CO_2, N_2O, and CH_4, and CO_2-E values are calculated for each pollutant based on each their GWP (Bernstein et al. 2008). In the 2021 draft inventory years, GWP factors were 1, 25, and 298 for CO_2, CH_4, and N_2O, respectively.

Combustion equipment (i.e., turbines and NGE) and combustion flares are the highest contributors to CO_2 emissions (Table 85). Those high contributions are expected since the combustion process converts hydrocarbons into energy and generates high rates of CO_2 gas as a by-product.

Venting excess hydrocarbons directly into the atmosphere without further processing is expected to reduce CO_2 emissions, but it also releases higher rates of CH_4 (see CH_4 emissions from fugitives and cold vents in Table 85). The GWP for CH_4 used to calculate CO_2-E for the 2021 draft data was 25. The calculated CO_2-E emissions from cold vents and NGE are comparable, but the CO_2 emissions from cold vents are drastically lower than CO_2 emissions from NGE (Table 85). CO_2-E emissions for cold vents are augmented by CH_4 contributions.

N_2O emissions are mostly emitted from flares, turbines, and boilers (Table 85). Although the emitted amount of N_2O is relatively low compared to CO_2, their overall impact is high since the GWP factor used to calculate CO_2-E based on the N_2O emissions in the 2021 draft data was 298.

Looking broadly on CO_2-E emissions, natural gas, diesel, or dual fuel turbines are the highest CO_2-E emitters (in bold), followed by NGE and cold vents.

> ***NOTE:*** In Table 85 and Table 86, "0" indicates that a value of 0 was calculated based on provided activity data, or that the process was zeroed out. A "-" indicates that the equipment type does not emit this pollutant. Bold numbers are the highest source contributors of that pollutant.

Table 85: 2021 draft total annual GHG emissions (tons/year) by equipment type

Equipment Type	CO_2 (GWP = 1)	CH_4 (GWP = 25)	N_2O (GWP = 298)	CO_2-E
Amine Unit	0	0	-	0
Boiler/Heater/Burner	159,617	3.04	2.88	160,551
Cold Vent	1,037	***40,022**	-	1,001,589
Combustion Flare	387,654	2,297	6.61	447,047
Drilling Equipment	22,661	1.11	-	22,688
Engine – Diesel or Gasoline Engine	223,830	5.17	-	223,959
Engine – Natural Gas	936,117	4,436	-	1,047,013
Fugitives	-	28,337	-	708,420
Glycol Dehydrator	-	325	-	8,130
Losses from Flashing	28.6	1,231	-	30,807
Mud Degassing	1.22	131	-	3,283
Pneumatic Controller	140	6,329	-	158,372
Pneumatic Pump	270	12,320	-	308,278
Storage Tank	-	187	-	4,677
Turbine – Natural Gas, Diesel, or Dual Fuel	***4,149,942**	320	***112**	***4,191,237**
Total	5,881,297.82	95,944.32	121.49	8,316,051

Note: * = highest source for that pollutant

6.6.2 Criteria and Precursor Emissions by Equipment Type

Table 86 presents 2021 draft criteria and precursor pollutant emissions from the 16 different equipment types. The main takeaways are as follows:

- CO is emitted at higher rates from the combustion equipment and combustion flares, possibly due to incomplete combustion processes.
- NO_x is emitted by the NGE in substantial amounts, followed by turbines.
- NGE's CO emissions and VOC emissions from cold vents are substantially higher than other criteria/precursor pollutants.

Table 86: 2021 draft total annual criteria pollutants and precursor emissions (tons/year) by equipment type

Equipment Type	NH_3	CO	Pb	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Boiler/Heater/Burner	***4.27**	111	7.19E-04	250	2.56	2.52	0.802	7.28
Cold Vent	-	-	-	-	-	-	-	***21,401**
Combustion Flare	0.348	996	5.44E-05	227	4.93	4.93	23.7	7,526
Drilling Equipment	-	117	-	439	7.87	7.69	0.208	11.2
Engine – Diesel or Gasoline Engine	-	1,228	-	5,219	259	***252**	348	309
Engine – Natural Gas	-	***22,891**	-	***16,340**	***74.5**	74.5	5	463
Fugitives	-	-	-	-	-	-	-	7,176
Loading Operation	-	-	-	-	-	-	-	0
Losses from Flashing	-	-	-	-	-	-	-	55.4
Pneumatic Controller	-	-	-	-	-	-	-	890
Pneumatic Pump	-	-	-	-	-	-	-	1,622
Storage Tank	-	-	-	-	-	-	-	189
Turbine – Natural Gas, Diesel, or Dual Fuel	-	3,044	***4.81E-03**	12,175	72.2	72.2	***1,157**	78.3
Total	**4.618**	**28,387**	**5.5834E-03**	**34,650**	**421.06**	**413.84**	**1,534.71**	**39,728.18**

Note: * = highest source for that pollutant

> ***NOTE:*** PM_{10} and $PM_{2.5}$ emissions in OCS AQS can be for filterable or primary depending on the equipment type.

The above data shows that the amount of pollutants released into the atmosphere varies greatly based on the type of equipment used and the method of release. Comparing the above data provided in the 2021 draft inventory to the historical data from the 2017 final data by equipment type allowed for greater detail in analysis, down to the level of a specific emission unit at a facility.

> ***NOTE:*** Portions of the data in this section have already been presented in Section 6.4, which provides an inventory-level overview. This section goes into a detailed analysis of the same data by equipment type.

The following Sections (6.6.3–6.6.5) provide a deeper assessment of the 2017 final and 2021 draft emissions based on equipment type. The equipment types are grouped into subcategories as follows:

- **Combustion equipment**, which consists of equipment types that burn fuels (diesel, gasoline, or natural gas) for operating, including BOI, DIE, DRI, NGE, and NGT (Section 6.6.3)

- **Combustion flares and cold vents**, which handle emissions from other emission units when their emissions are not vented locally (flare or vented remotely) (Section 6.6.4)

- **Non-combustion equipment**, which includes amine units (AMI), fugitives (FUG), glycol dehydrator (GLY), loading operations (LOA), losses from flashing (LOS), mud degassing (MUD), pneumatic pump (PNE), pneumatic controllers (PRE), and storage tanks (STO) (Section 6.6.5)

Emissions from all equipment subcategories will be compared to 2017 final emissions to identify notable discrepancies and investigate underlying causes for these inconsistencies.

6.6.3 Emissions by Combustion Equipment

This section compares 2017 final and 2021 draft emissions from combustion equipment to investigate any discrepancies between them and identify the underlying causes for those inconsistencies (if found).

Table 87 compares the combustion equipment count in the 2021 draft and 2017 final data. Table 88 and Table 89 presents a breakdown of the GHG and criteria pollutants and precursors emissions from all equipment types in the 2021 draft and 2017 final data. Figure 46 and Figure 47 are the visual presentations for Table 88 and Table 89, respectively.

Figure 46 subsections display the following information:

- CO_2 emissions decreased between 2017 final and 2021 draft inventories, and biggest contributions came from NGT and NGE.
- CO_2-E emissions decreased between 2017 final and 2021 draft inventories, and biggest contributions came from NGT and NGE.
- CH_4 emissions decreased between 2017 final and 2021 draft inventories; the only contributors were NGE and NGT, with the biggest contribution coming from NGE.
- N_2O emissions increased between 2017 final and 2021 draft inventories; the only contributors were BOI and NGT, with the biggest contribution coming from NGT.

Figure 47 subsections display the following information:

- CO emissions decreased between 2017 final and 2021 draft inventories, and the biggest contributor was NGE.
- NOx emissions decreased between 2017 final and 2021 draft inventories, and biggest contributions came from NGT and NGE.
- VOC emissions decreased between 2017 final and 2021 draft inventories, and the biggest contributor was NGE.
- SO_2 emissions increased between 2017 final and 2021 draft inventories and were due entirely to NGT.
- NH_3 emissions decreased between 2017 final and 2021 draft inventories, and the only contributor was BOI.
- Pb emissions increased between 2017 final and 2021 draft inventories, and though boiler (BOI) emissions decreased, it was made up for by an increase in emissions from the NGT.

In the following sections, emissions from each combustion equipment will be analyzed individually.

> ***NOTE:*** In Table 88 and Table 89, "0" indicates that a value of 0 was calculated based on provided activity data, or that the process was zeroed out. A "-" indicates that the equipment type does not emit this pollutant.

NOTE: PM_{10} and $PM_{2.5}$ emissions are not presented in Figure 47 because, in the 2021 draft inventory, they were not differentiated into filterable or primary, as opposed to the 2017 final data. Consequently, comparing the 2021 draft inventory total PM_{10} emissions (from all equipment types) against the 2017 final PM_{10} emissions will not provide a representative picture of the discrepancies between the two reporting years.

The three tables presented below show that various combustion equipment types have considerable differences when comparing their 2017 final emissions with the 2021 draft emissions. In the following sections, emissions from each combustion equipment type will be analyzed individually to understand the underlying reasons for those discrepancies and identify data entry issues that could be causing the disparities.

Table 87: Combustion equipment count (number) by inventory year with % change

Equipment Type	Description	2017 Final	2021 Draft (Emitting Equipment)	Difference	Percentage Change[a]
BOI	Boiler/Heater/Burner	403	252 of 422	- 151	- 37.46%
DRI	Drilling Equipment	12	13 of 15	+ 1	+ 8.33%
DIE	Engine – Diesel or Gasoline Engine	2,144	1,670 of 2,442	- 474	- 22.11%
NGE	Engine – Natural Gas	1,151	708 of 1,199	- 443	- 38.48%
NGT	Turbine – Natural Gas, Diesel, or Dual Fuel	359	425 of 437	+ 66	+ 18.38%
-	**Total Combustion Equipment Count**	**4,069**	**3,068 of 4,522**	**- 1,001**	**- 24.6%**

Note: [a] $Percentage\ Change = \frac{\text{2021 draft emitting equipment count} - \text{2017 final equipment count}}{\text{final 2017 equipment count}} \times 100\%$

NOTE: The equipment counts in Table 87 represent the individual pieces of equipment, not the number of the processes associated with them; if a piece equipment has two processes linked to it, it is still counted as one.

NOTE: The 2021 draft equipment count includes all equipment reported in the 2021 draft inventory. In some instances, the actual count of emitting pieces of equipment can be less than the reported because of zeroed-out processes or because some of the pieces of equipment are under non-operational platforms. When needed, the count breakdown will be provided in the following sections.

Table 88: GHG emissions (tons/year) from combustion equipment by inventory year

Equipment Type	CO_2 (GWP = 1) 2017 Final	CO_2 (GWP = 1) 2021 Draft	CH_4 (GWP = 25) 2017 Final	CH_4 (GWP = 25) 2021 Draft	N_2O (GWP = 298) 2017 Final	N_2O (GWP = 298) 2021 Draft	CO_2-E 2017 Final	CO_2-E 2021 Draft
BOI	291,729	159,617	5.46	3.04	5.27	2.88	293,435	160,551
DRI	25,844	22,661	1.25	1.11	-	-	25,875	22,688
DIE	212,150	223,830	5.91	5.17	-	-	212,297	223,959
NGE	1,978,765	936,117	10,414	4,436	-	-	2,239,107	1,047,013
NGT	3,839,648	4,149,942	298	320	104	112	3,878,122	4,191,237

Note: Refer to Table 84 for equipment type descriptions.

Table 89: Criteria pollutants and precursors emissions (tons/year) from combustion equipment by inventory year

Equip-ment Type	CO 2017 Final	CO 2021 Draft	NO_x 2017 Final	NO_x 2021 Draft	PM_{10} 2017 Final	PM_{10} 2021 Draft	$PM_{2.5}$ 2017 Final	$PM_{2.5}$ 2021 Draft	SO_2 2017 Final	SO_2 2021 Draft	VOC 2017 Final	VOC 2021 Draft	NH_3 2017 Final	NH_3 2021 Draft	Pb 2017 Final	Pb 2021 Draft
BOI	200	111	243	250	4.85	2.56	4.58	2.52	3.61	0.802	13.1	7.28	7.85	4.27	0.00161	7.19E-4
DRI	133	117	501	439	8.93	7.87	8.77	7.69	0.237	0.208	12.5	11.2	-	-	-	-
DIE	1,151	1,228	4,791	5,219	212	259	213	252	381	348	241	309	-	-	-	-
NGE	46,190	22,891	32,945	16,340	158	74.5	158	74.5	10.6	5	1,074	463	-	-	-	-
NGT	2,836	3,044	11,178	12,175	66.6	72.2	66.6	72.2	44.1	1,157	72.9	78.3	-	-	0.00209	0.00481

Note: Refer to Table 84 for equipment type descriptions.

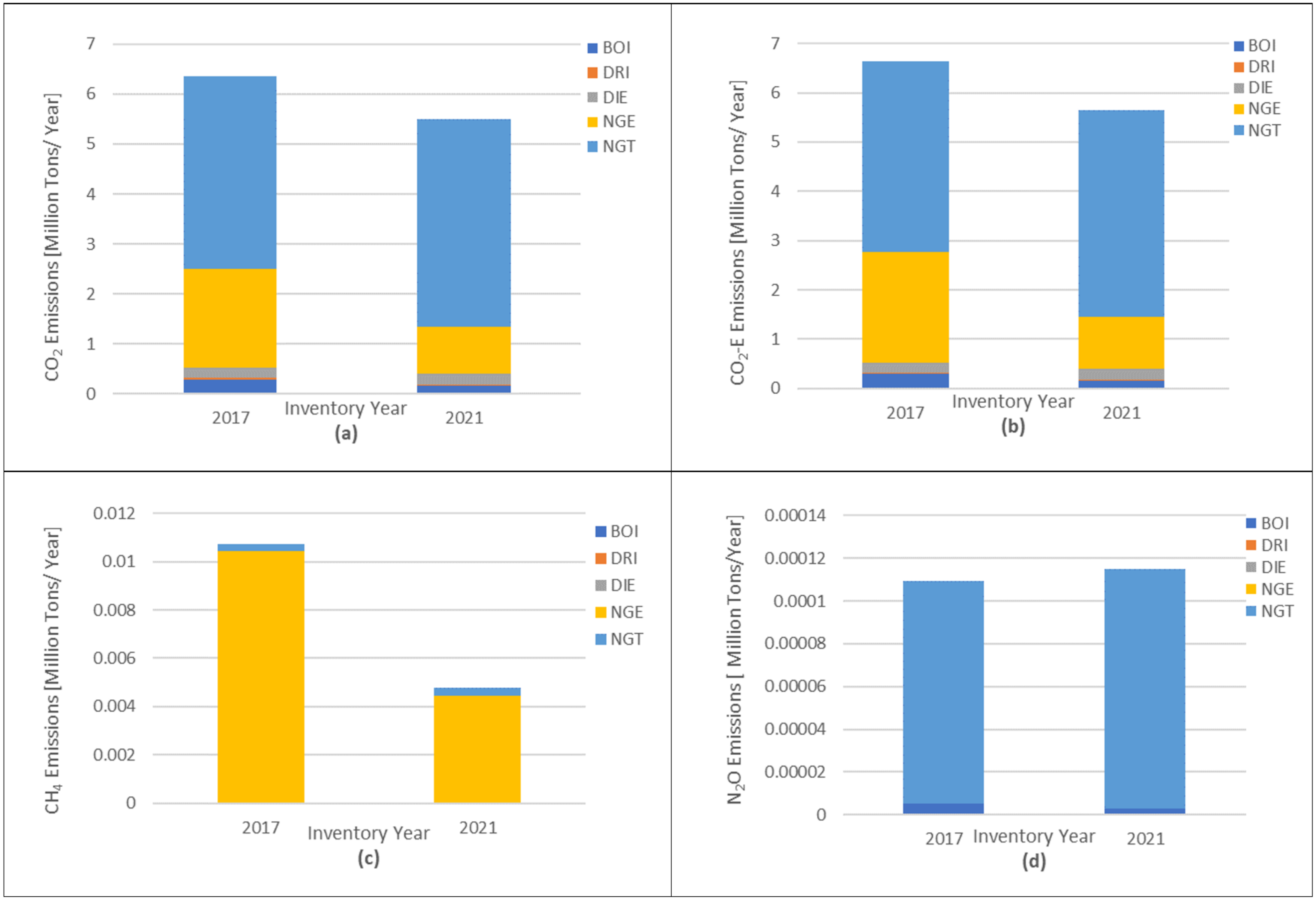


Figure 46: GHG emissions by combustion equipment for 2017 final and 2021 draft data

See Table 84 for equipment type descriptions key.

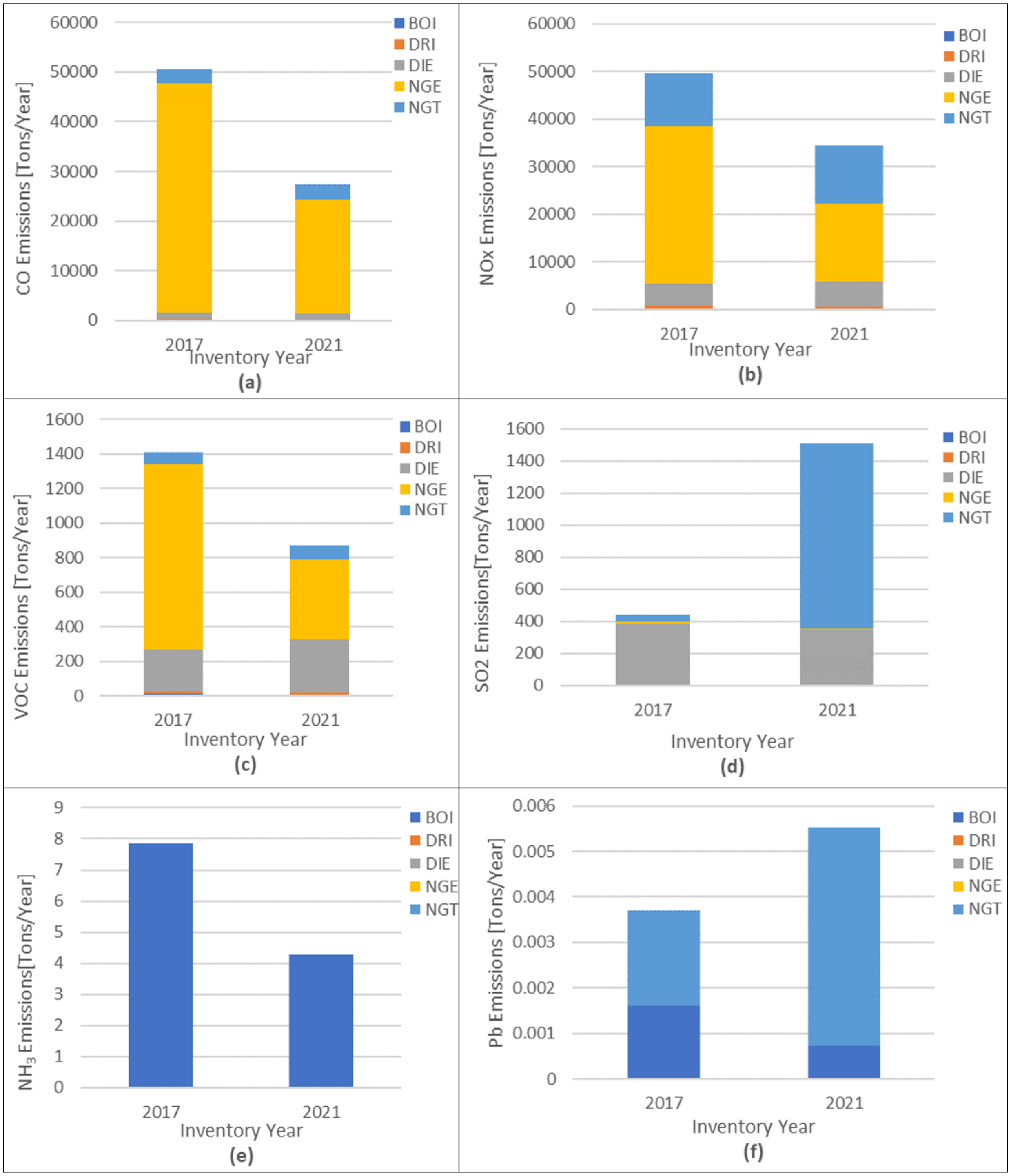


Figure 47: Criteria and precursor emissions by combustion equipment for 2017 final and 2021 draft data

See Table 84 for equipment type descriptions key.

6.6.3.1 Boiler/Heater/Burner (BOI)

In OCS AQS, BOI equipment type has three independent processes that users can select from, depending on the calculator type and description (Table 90). Calculators BOI-M01R and BOI-M02R calculate emissions from liquid-fueled boiler processes, while BOI-M03R is used for gas-fueled boiler processes.

Table 90: Boiler/heater/burner calculators in OCS AQS used in the 2021 draft inventory

Calculator ID	Calculator Description
BOI-M01R	Boilers, Heaters, and Burners (Liquid-fueled Units Powered by Diesel)
BOI-M02R	Boilers, Heaters, and Burners (Liquid-fueled Units Powered by Waste Oil)
BOI-M03R	Boilers, Heaters, and Burners – Natural, Process, or Waste Gas

Looking at the data in Table 91, the annual fuel usage by emitting processes decreased by 44.07% because of the 38.04% decrease in the count of emitting gas-fueled boiler processes. Conversely, although actively emitting liquid-fueled boiler processes count did not change in the 2021 draft, the total annual fuel used by those liquid-fueled boilers decreased by 86.47%.

Table 91: Boiler/heater/burner process count and fuel usage by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Gas-Fueled Boiler Processes Reported in the Inventory	397	422	+ 6.30%
Number of **Active Emitting** Gas-Fueled Boiler Processes	397 of 397	246 of 422	- 38.04%
Total Fuel Usage by Active Emitting Gas-Fueled Boiler Processes [Mscf]	4,730,809.44	2,645,770.30	- 44.07%
Number of Liquid-Fueled Boiler Processes Reported in the Inventory	6	7	+ 16.67%
Number of **Active Emitting** Liquid-Fueled Boiler Processes	6 of 6	6 of 7	0.00%
Total Fuel Usage by Active Emitting Liquid-Fueled Boiler Processes [lb]	5,017,792.04	678,765.3065	- 86.47%

Emissions are directly proportional to boilers' fuel usage throughputs, and an overall decrease of boilers' emissions was expected in 2021 draft emissions. The decrease in boilers' emissions was expected to be approximately around 45% (ranging around the decrease in total fuel usage by active emitting gas-fueled boiler processes) because emitting gas-fueled boilers comprise more than 97% of the 2021 draft inventory active emitting boilers. In future inventory efforts, operators be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data.

> ***NOTE:*** The 86.47% decrease of the liquid fuel usage by boilers was suspicious given that the count of active emitting liquid-fueled boilers did not change in the 2021 draft inventory. With further investigation, it was found that the 2017 annual liquid fuel usage by one liquid-fueled boiler under Facility ID# 2503-1 operated by Shell Offshore Inc. was entered as 74,690.51 lb (98.2% lower than the fuel used in the 2017 final inventory) but was 4,125,348.44 lb (82% of the total liquid fuel usage in 2017). Therefore, that substantial change in the fuel usage by that facility caused that observed 86.47% decrease of the boilers' liquid fuel usage in 2021 draft. The Team attempted to contact the operator of Facility ID# 2503-1 via email but did not receive a reply to this request.

Table 92 compares the annual emissions from BOI emission units in the 2017 final and 2021 draft data. As expected, for most pollutants, annual emissions decreased by approximately 44%. However, for NO_x and SO_2, the percentage change in emissions deviated from this anticipated trend, which suggests that factors other than the decrease in throughput caused the discrepancies in emissions. In the following subsections, investigations are conducted to study the discrepancies in BOI NO_x and SO_2 emissions.

Table 92: Boiler/heater/burner emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CO_2	291,729	159,617	- 132,112	- 45%
CH_4	5.46	3.04	- 2.42	- 44%
N_2O	5.27	2.88	- 2.39	- 45%
CO_2-E	293,435	160,551	- 132,884	- 45%
CO	200	111	- 89	- 45%
NO_x	243	250	+ 7	+ 3%
SO_2	3.61	0.802	- 2.81	- 78%
VOC	13.1	7.28	- 5.82	- 44%
NH_3	7.85	4.27	- 3.58	- 46%
PM_{10}-FIL	4.85	2.56	- 2.29	- 47%
$PM_{2.5}$-FIL	4.58	2.52	- 2.06	- 45%
Pb	0.00161	0.000719	- 0.000891	- 55%

Note: For NO_x, see Section 6.6.3.1.1 and for SO_2, see Section 6.6.3.1.2.

6.6.3.1.1 Investigations of BOI NO_x Emissions

Table 92 shows that NO_x emissions increased from 243 tons in the 2017 final data to 250 tons in the 2021 draft data (a 3% increase). Although this increase is not considered significant, it raises questions as to why it deviates from the expected emission decrease of approximately 44% due to the BOI fuel usage decrease.

As previously mentioned, BOI equipment type in the 2021 draft effort has three independent processes that users can select from, depending on the calculator type and description. A default EF is used for each calculator based on the values provided in USEPA AP-42 (USEPA 1995). The listed EFs used in the 2017 inventory depend on the maximum rated heat input; see footnotes for Tables 4.3, 4.4, and 4.5 in Wilson et al. (2019). By default, one value for the NO_x EF is used in the 2021 draft inventory, and operators should provide NO_x reduction efficiency values under the control request tab of boilers to account for the variations of EFs depending on the maximum rated heat input; if users do not provide NO_x reduction efficiency, the default EF value will be used in calculating the emissions. Table 93 below compares the BOI default NO_x EFs used in 2021 draft and 2017 final inventory.

In some cases, alternative values of NO_x EFs are lower than the default values used in the 2021 draft inventory in OCS AQS. The Team analyzed the provided reduction efficiencies for all BOI processes to check if operators considered the variations in NO_x EFs in the 2021 draft inventory. Only one BOI process considered the impact of the maximum fuel-rated heat input and provided NO_x reduction efficiency. All other BOI processes used the default values and did not reduce the NO_x emissions based on the fuel maximum rated heat input. Therefore, it can be concluded that this discrepancy in EFs that resulted from not using NO_x reduction efficiency fields in OCS AQS caused the observed 3% increase in the NO_x emissions shown in Table 92.

Table 93: NO_x EFs by boiler/heater/burner calculator by inventory year

#	Calculator ID	2021 Draft (Default Value)	2017 Final
1	BOI-M01R	24 (lb/10^3 gal)	24, 20 or 10 (lb/10^3 gal)
2	BOI-M02R	47 (lb/10^3 gal)	55, 47, or 40 (lb/10^3 gal)
3	BOI-M03R	190 (lb/MMscf)	190 ,140, or 100 (lb/MMscf)

6.6.3.1.2 Investigations of BOI SO_2 Emissions

SO_2 emissions decreased from 3.61 tons in the 2017 final data to 0.802 tons in the 2021 draft data (a 78% decrease) (Table 92). This decrease is considerably higher than the decrease in the other pollutants' emissions. This suggests that other factors affected the SO_2 emissions from BOI emission units.

As previously mentioned, BOI equipment type in the 2021 draft effort in OCS AQS has three independent processes that users can select from, depending on the calculator type and description. For each calculator, an EF is used based on the values provided in USEPA's AP-42 (USEPA 1995). Table 94 shows the SO_2 EFs for each calculator type. As shown in Table 94, for BOI-M01R and BOI-M02R (liquid-fueled boilers), SO_2 EFs are a function of the fuel sulfur content. This variable was requested from the operators in the data request tab in OCS AQS for the 2021 effort. Therefore, aside from the 86.5% decrease in the liquid fuel usage, the user-defined sulfur content can also impact the overall SO_2 emissions from liquid-fueled BOI emission units.

Table 94: SO_2 EFs by boiler/heater/burner calculator used in the 2021 draft inventory

Calculator ID	SO_2 EF
BOI-M01R	142 × S (lb/10^3 gal)
BOI-M02R	157 × S (lb/10^3 gal)
BOI-M03R	0.60 (lb/MMscf)

Note: S = Fuel sulfur content (wt%)

A closer analysis was conducted on the emission units linked to those two calculators (BOI-M01R and BOI-M02R) to study the provided sulfur content values and compare them to those provided in the 2017 final inventory. Table 95 lists the seven liquid-fueled boiler processes (with the associated facilities and companies) and compares their provided sulfur content values in the 2021 draft and 2017 final inventories. The values provided in the 2021 draft data are inconsistent with and considerably reduced from those provided in the 2017 final data. Consequently, the decrease in the fuel usage, along with the decrease in the sulfur content, resulted in the observed decrease in the SO_2 BOI emissions.

The lower fuel sulfur content in the 2021 draft data could result from data entry errors or could be due to a change in the type of fuel used or the usage of ultra-low sulfur fuels. As part of the data QA checks, the Team contacted the operators of the facilities listed in Table 95 to confirm the accuracy of the provided data. As a result, the operators for Murphy Exploration & Production Company – USA and Shell Offshore Inc confirmed the accuracy of the provided sulfur content in the 2021 draft inventory and stated that only ultra-low sulfur fuel is used at their facilities.

Table 95: Anomalous fuel sulfur content (wt%) in boiler/heater/burner emission units in 2021 draft data

#	Company Name	Facility ID	Emission Unit	2017 Final Fuel Sulfur Content [wt%]	2021 Draft Fuel Sulfur Content [wt%]
1	Sea Robin Pipeline Company, LLC	25012-2	8247	0.01	-
2	Shell Offshore Inc	2503-1	BOI700-D	0.05	0.0015
3	Shell Offshore Inc	2503-1	BOI702-D	Emission unit did not exist in 2017	0.00015
4	Murphy Exploration & Production Company – USA	2229-1	IGGB-D	0.03	0.0015
5	Murphy Exploration & Production Company – USA	2229-1	DFHBA-D	0.03	0.0015
6	Murphy Exploration & Production Company – USA	2229-1	IGGA-D	0.03	0.0015
7	Murphy Exploration & Production Company – USA	2229-1	DFHBB-D	0.03	0.0015

6.6.3.2 Drilling Equipment (DRI)

In the 2021 effort in OCS AQS, DRI equipment type has three independent processes that users can select from, depending on the calculator type and description (Table 96).

> ***NOTE:*** DRI analyzed in this section account only for the ones that are associated with platforms, not mobile drilling rigs. Mobile drilling rigs are analyzed in Section 9.1.

Table 96: Drilling equipment calculators in OCS AQS used in the 2021 draft inventory

Calculator ID	Calculator Description
DRI-M01R	Drilling Equipment-Gasoline Fuel
DRI-M02R	Drilling Equipment-Diesel Fuel
DRI-M03R	Drilling Equipment-Natural Gas Fuel

Fuel usage in DRI (throughput) is directly proportional to emissions, and a decrease in throughput would cause a corresponding decrease in the final calculated emissions. Table 97 shows that, although the active emitting DRI count increased by 8.33% (one additional emitting DRI equipment was added in the 2021 draft effort), the amount of fuel used in DRI equipment decreased by almost 13%. This percentage decrease is acceptable, as the operational conditions might differ from year to year. As generated emissions are directly proportional to the fuel used, it is expected that the emissions from DRI would decrease by around 13%.

Table 98 compares emissions from the DRI emission units in the 2021 draft and 2017 final data. For all the pollutants, annual emissions decreased by 10–12%, which is close to the observed fuel usage decrease of 13%. Therefore, it can be concluded that the reduction in the 2021 emissions from DRI is due to the decrease in throughput, and the activity data for DRI emission units provided for 2021 can be considered reliable and do not require further corrective action.

Table 97: Drilling equipment process count and fuel usage by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Drilling Equipment Processes Reported in the Inventory	12	15	+ 25%
Number of **Active Emitting** Drilling Equipment Processes	12 of 12	13 of 15	+ 8.33%
Total Diesel Fuel Usage [gallons]	2,302,281.65	2,004,478.53	- 12.9%
Total Natural Gas Fuel Usage [Mscf]	0	0	-

Table 98: Drilling equipment emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CO_2	25,844	22,661	- 3,183	- 12%
CH_4	1.25	1.11	- 0.14	- 11%
CO_2-E	25,875	22,688	- 3,187	- 12%
CO	133	117	- 16	- 12%
NOx	501	439	- 62	- 12%
SO_2	0.237	0.208	- 0.03	- 12%
VOC	12.5	11.2	- 1.30	- 10%
PM10-PRI	8.93	7.87	- 1.06	- 11.87
PM2.5-PRI	8.77	7.69	- 1.08	- 12.3

6.6.3.3 Engine – Diesel or Gasoline Engine (DIE)

In the 2021 effort in OCS AQS, DIE equipment type has three independent processes that users can select from, depending on the calculator type and description (Table 99).

Table 99: Diesel or gasoline engine calculators in OCS AQS used in the 2021 draft inventory

Calculator ID	Calculator Description
DIE-M01R	Gasoline Engines
DIE-M02R	Diesel Engines Where Max HP < 600
DIE-M03R	Diesel Engines Where Max HP >= 600

Table 100 shows that, although the count of active emitting DIE equipment decreased in the 2021 draft inventory, the fuel used in the DIE equipment increased by almost 6%. DIE-generated emissions are directly proportional to the fuel usage; therefore, it is expected that the emissions from DIE would increase by around 6% as well.

Table 101 compares emissions from DIE emission units in the 2017 final and 2021 draft data. CO_2, CO_2-E, CO, and NO_x emissions increased, as expected, by the amount ranging between 5 to 9%, which corresponds to the increase in throughput. However, CH_4 and SO_2 emissions decreased in 2021, conflicting with expected behavior based on the throughput change; VOC increased by 28%, which is much higher than expected.

The following subsections examine the discrepancies in CH_4, SO_2, and VOC emissions from diesel and gasoline engines.

Table 100: Diesel or gasoline engine process count and fuel usage by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Diesel and Gasoline Engines Processes Reported in the Inventory	2,144	2,442	+13.89%
Number of **Active Emitting** Diesel and Gasoline Engines Processes	2,144 of 2,144	1,670 of 2,442	-22.1%
Total Fuel Usage [gallons]	18,829,119	19,921,133	+5.8

Table 101: Diesel or gasoline engine emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change	See Section
CO_2	212,150	223,830	+ 11,680	+ 6%	-
CH_4	5.91	5.17	- 0.7	- 13%	6.6.3.3.1
CO_2-E	212,297	223,959	+ 11,662	+ 5%	-
CO	1,151	1,228	+ 77	+ 7%	-
NOx	4,791	5,219	+ 428	+ 9%	-
SO_2	381	348	- 33	- 9%	6.6.3.3.2
VOC	241	309	+ 68	+ 28%	6.6.3.3.3

6.6.3.3.1 Investigations of Diesel or Gasoline Engine CH_4 Emissions

CH_4 emissions from DIE decreased from 5.91 tons in the 2017 final data to 5.17 tons in the 2021 draft data (a 13% decrease) (Table 101). Although this change is not considered significant, it raises questions because the emissions did not increase as expected based on the increase in the DIE fuel usage.

Among these three DIE calculators that users can select from, DIE-M03R (diesel engines where max HP >= 600) is the only calculator with an EF for CH_4. Therefore, the CH_4 from DIE equipment is only calculated from the diesel engines where max HP >= 600 from this type of emission source. Based on this, a deeper analysis was conducted only on the throughput of the emission units with the assigned calculator of DIE-M03R (diesel engines where max HP >= 600).

Table 102 compares overall throughputs for diesel engines where max HP >= 600. The throughputs to the diesel engines where max HP >=600 decreased by 12% (despite an increase in overall throughput to all DIE emission units). Therefore, the 13% decrease in CH_4 is consistent with the decrease in throughputs to the diesel engines that emit CH_4. This demonstrates that the CH_4 emission did not, in fact, deviate from the expected trend. As such, 2021 draft data provided for DIE-M03R (diesel engines where max HP >= 600) units can be considered reliable and does not require further corrective actions.

Table 102: Fuel usage (gal/year) by inventory year in diesel engines where max HP >= 600

Parameter	2017 Final	2021 Draft	% Change
Total Fuel Usage [gallons] in Diesel Engines Where Max HP >= 600 (DIE-M03R)	10,778,531.43	9,470,179.48	- 12.14%

6.6.3.3.2 Investigation on Diesel or Gasoline Engine SO_2 Emissions

SO_2 emissions from DIE decreased from 381 tons in the 2017 final data to 348 tons in the 2021 draft data (a 9% decrease) (Table 101). Although this decrease is not considered significant, it raises questions since the emissions do not increase as expected based on the increase in the DIE fuel usage in the 2021 draft data.

As previously mentioned, the DIE equipment type in OCS AQS has three independent processes that users can select from, depending on the calculator type and description. An EF is used for each calculator based on the values provided in AP-42 (USEPA 1995). Unlike DIE-M03R, DIE-M01R and DIE-M02R (DIE emission units fueled by gasoline and diesel fuel where max HP<600, respectively) calculators have constant SO_2 EFs and do not depend on the sulfur content values (Table 103). SO_2 emissions from processes using the DIE-M01R and DIE-M02R rely solely on the fuel throughput, and an increase in that throughput should lead to a corresponding rise in their SO_2 emissions. On the other hand, for processes using the DIE-M03R calculator, both the throughput and the fuel sulfur content values impact the overall emitted SO_2 emissions.

Table 103: SO_2 EFs by DIE calculator used in the 2021 draft inventory

Calculator ID	SO_2 EF
DIE-M01R	0.084 (lb/MMBtu)
DIE-M02R	0.290 (lb/MMBtu)
DIE-M03R	1.01 × S (lb/MMBtu)

Notes: S = Fuel sulfur content (wt%)

Table 104 shows the breakdown of the SO_2 emissions from the 3 DIE calculators and compares emissions in the 2017 final and 2021 draft data. This table displays that the SO_2 emissions from processes using the DIE-M01R and DIE-M02R increased in the 2021 draft data, as was expected from the increased throughput (Section 6.6.3.3).

The third calculator that can be used for a diesel engine process is DIE-M03R, and the emissions calculated using this calculator depend on the fuel sulfur content. Given that issues were previously detected with the operator-provided fuel sulfur content values for other equipment types (Sections 6.5.5 and 6.6.3.1), sulfur content values provided for the DIE emission units for the 2021 draft data were analyzed more closely.

Figure 48 compares the 2017 final and 2021 draft entries for DIE sulfur content. This figure shows that 84% of entries (3,106 entries) were 0.0015 wt% in the 2021 draft data, while only 20% of entries in 2017 final data were equal to 0.0015 wt%. More than 50% of the provided entries for sulfur content in the 2017 final data were 0.5 wt%. This level is considerably higher than 0.0015 and contributed to the decrease in SO_2 emissions in the 2021 draft data. This demonstrates that most units in the 2021 draft data use fuels with ultra lower sulfur content, which would impact emissions and cause the observed decrease in SO_2 emissions.

Also important, 34 monthly entries were equal to 4 wt%. Looking at other entries from both 2021 draft and 2017 final data, this value is considerably high. The Team contacted the operator of the facilities in Table 105 to verify the high value of 4 wt%. The red box in Figure 48 highlights those 34 monthly entries and shows how they deviate from all other entries. The operators confirmed that the values were inaccurately entered and corrected them to 0.0015%. This correction changed the DIE SO_2 emissions from the 2021 draft data of 348 tons to the 2021 final data of 241 tons (Section 8).

Table 104: DIE SO_2 emissions (tons/year) by calculator type by inventory year with % change

Calculator ID	2017 Final	2021 Draft	% Change
DIE-M01R	0.00475	0.00955	+ 101%
DIE-M02R	159.3083	207.226	+ 30%
DIE-M03R	221.4214	140.74	- 36%

Table 105: Facilities with a fuel sulfur content (wt%) of 4 in DIE emission units in 2021 draft data by inventory year

Company Name	Facility ID	Emission Unit	2017 Final	2021 Draft
Cox Operating LLC	21809-4	DGE-01	This facility did not exist in 2017	4
Cox Operating LLC	21809-4	DGE-02	This facility did not exist in 2017	4
Cox Operating LLC	21411-11	ZAN-0902	0.5	4

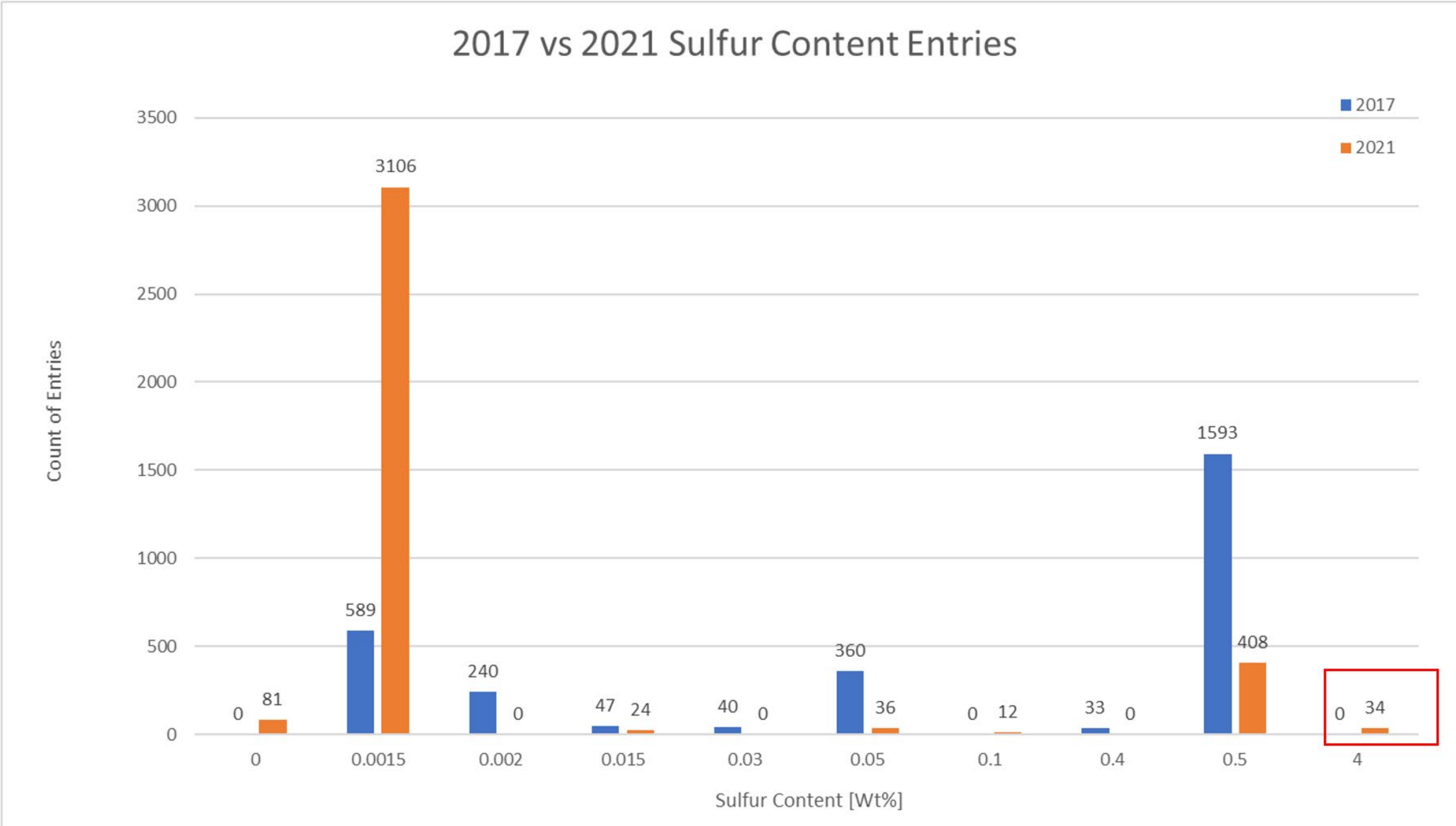


Figure 48: Count of DIE sulfur content entries by sulfur content (wt%) for 2017 final (blue, left columns) and 2021 draft (orange, right columns) data

Red box in highlights the 34 DIE sulfur content entries having erroneous high values.

6.6.3.3.3 Investigation of Diesel or Gasoline Engine VOC Emissions

VOC emissions increased from 241 tons in the 2017 final data to 309 tons in the 2021 draft data (a 28% increase) (Table 101). This moderate increase raises questions as it is higher than expected based on the increased DIE fuel usage in the 2021 draft data.

As previously mentioned, the DIE equipment type in OCS AQS has three independent processes that users can select from, depending on the calculator type and description (Table 106).

The VOC EF used in the 2021 draft effort for calculator DIE-M02R is 0.36 lb/MMBtu, while the value used in the 2017 final effort was 0.33 lb/MMBtu. The value used in OCS AQS for the 2021 draft effort came from Table 3.3-1 of the USEPA's AP-42 document, resulting from the summation of Exhaust, Evaporative, Crankcase and, Refueling EFs (USEPA 1995).

It can be concluded that this discrepancy in the VOC EF caused the increase in calculated VOC emissions and affected the overall emitted VOCs from DIE engines beyond the increased throughput alone. This conclusion suggests that there is no issue with data entry or calculations, and there is no need for further corrective actions on the DIE emission units.

Table 106: VOC EFs by DIE calculator by inventory year

Calculator ID	2017 Final	2021 Draft
DIE-M01R	3.030 (lb/MMBtu)	3.030 (lb/MMBtu)
DIE-M02R	0.330 (lb/MMBtu)	0.360 (lb/MMBtu)
DIE-M03R	0.080 (lb/MMBtu)	0.080 (lb/MMBtu)

6.6.3.4 Engines – Natural Gas (NGE)

In the OCS AQS 2021 draft effort, NGE equipment type has four independent processes that users can select from, depending on the calculator type and description (Table 107).

Table 107: NGE calculators in OCS AQS used in the 2021 draft inventory

Calculator ID	Calculator Description
NGE-M01R	NGE Where Engine Stroke Cycle = 2-Cycle and Engine Burn = Lean
NGE-M02R	NGE Where Engine Stroke Cycle = 4-Cycle and Engine Burn = Lean
NGE-M03R	NGE Where Engine Stroke Cycle = 4-Cycle and Engine Burn = Rich
NGE-M04R	NGE Where Engine Burn Type = Clean

Fuel usage in NGE (throughput) is directly proportional to emissions, and a decrease in throughput should cause a decrease in the final calculated emissions. Table 108 shows that the amount of fuel used in NGE equipment decreased by almost 55%. Given this decrease, the emissions from NGE are expected to decrease by around 55%. Table 109 compares emissions from the NGE emission units in the 2021 draft and 2017 final data.

Table 108: NGE process count and fuel usage by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Natural Gas Processes Reported in the Inventory	1,151	1,199	+ 4.17%
Number of **Active Emitting** Natural Gas Processes	1,151 of 1,151	708 of 1,199	- 38.49%
Total Fuel Usage by Active Emitting Processes [Mscf]	33,872,765	15,334,732	- 54.73%

Table 109: NGE emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CO_2	1,978,765	936,117	- 1,042,648	- 53%
CH_4	10,414	4,436	- 5,978	- 57%
CO_2-E	2,239,107	1,047,013	- 1,192,094	- 53%
CO	46,190	22,891	- 23,299	- 50%
NOx	32,945	16,340	- 16,605	- 50%
SO_2	10.6	5	- 6	- 53%
VOC	1,074	463	- 611	- 57%
PM10-FIL	158	74.5	- 84	- 53%
PM2.5-FIL	158	74.5	- 84	- 53%

From analysis, the annual emissions, for all pollutants, decreased between 53 to 57%. Therefore, it can be concluded that the decrease in the 2021 draft emissions is due to the reduction in throughput for the NGE emission units. In future inventory efforts, the operator will be able to analyze their activity data (in this case, fuel usage) as a deviation of their average reported historical values by a percentage selected by the operator. This feature should flag activity data that could be in error for correction before operators submit emissions data.

6.6.3.5 Turbines – Natural Gas, Diesel, or Dual Fuel (NGT)

In the OCS AQS 2021 draft effort, NGT equipment type has three independent processes that users can select from, depending on the calculator type and description (Table 110).

Table 110: NGT calculators in OCS AQS used in the 2021 draft inventory

Calculator ID	Calculator Description
NGT-M01R	Dual-Fuel Turbines – Nat. Gas – Known Sulfur
NGT-M02R	Dual-Fuel Turbines – Nat. Gas – Unknown Sulfur
NGT-M03R	Dual-Fuel Turbines – Diesel

Fuel usage in NGT (throughput) is directly proportional to emissions, and an increase in throughput should cause an increase in the final calculated emissions. Table 111 shows that the amount of natural gas fuel used in NGT equipment increased by 2.9%, and the amount of diesel fuel used increased by 44.7%. The amount of diesel fuel use increased because the number of active emitting NGT-D processes increased by 56%. Based on the number of NGT processes and corresponding throughputs, an increase of around 12% would be expected. Table 111 compares emissions from the NGT emission units in 2021 draft and 2017 final data.

Table 111: NGT process count and fuel usage by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of NGT Processes Reported in the Inventory	350	399	+ 14.00%
Number of **Active Emitting** NGT Processes	350 of 350	336 of 399	- 4.00%
Total Fuel Usage by Active Emitting Processes [Mscf]	58,631,713.19	60,321,144.52	+ 2.88%
Number of NGT-D Processes Reported in the Inventory	57	111	+ 94.74%
Number of **Active Emitting** NGT-D Processes	57 of 57	89 of 111	+ 56.14%
Total Fuel Usage by Active Emitting NGT-D Processes [Gallons]	3,468,139.36	5,017,722.15	+ 44.68%

Table 112: NGT emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CO_2	3,839,648	4,149,942	310,294	+ 8.08%
CH_4	298	320	22	+ 7.38%
N_2O	104	112	8	+ 7.69%
CO_2-E	3,878,122	4,191,237	313,115	+ 8.07%
CO	2,836	3,044	208	+ 7.33%
NOx	11,178	12,175	997	+ 8.92%
SO_2	44.1	1,157	1,113	+ 2,523.58%*
OC	72.9	78.3	5	+ 7.41%
PM_{10}-FIL	66.6	72.2	6	+ 8.41%
$PM_{2.5}$-FIL	66.6	72.2	6	+ 8.41%
Pb	0.00209	0.00481	0	+ 130.14%

Note: * See Section 6.5.5.2

From analysis, annual emissions for most of the pollutants increased by an acceptable amount, except for the Pb and SO_2. The issues with NGT SO_2 emissions have been discussed in detail in Section 6.5.5.2. Therefore, no further investigation on SO_2 is conducted in this section.

Pb emissions increased by 130%, which is unexpectedly high. Lead is only emitted from diesel turbines and, as previously seen in Table 111, an increase of 44.7% in the diesel throughput would account for some of the change in the emission levels. The remaining amount may be accounted for by the fact that, in the 2021 draft data, the default diesel heating value of 19,300 Btu/lb was used to calculate Pb emissions. In contrast, in the 2017 final data the operators were flexible in what value was used in the calculations. The values provided in the 2017 final data ranged from 17,329 Btu/lb to 20,139 Btu/lb, with vast majority of the values below the 19,300 Btu/lb used in the 2021 draft data.

6.6.4 Emissions by Vents and Flares

Cold vents and combustion flares handle the emissions from various sources that are not vented locally or routed to system. Cold vents can emit higher rates of hydrocarbons (depending on the composition of the vented gas) as they release their raw feed gas to the atmosphere without further processing. In contrast, the combustion flares dispose of the constituents of the feed flare gas by burning it. As a result, the combustion process that occurs in the flares produces high rates of CO_2, CO, NO_x, N_2O, and SO_2 as by-products of the combustion process.

Table 113 compares the cold vent and flare equipment counts in 2017 final and 2021 draft data. Table 114 and Table 115 illustrate the difference in cold vent and flare emissions in 2017 final and 2021 draft data. Figure 49 and Figure 50 are the visual presentations for Table 114 and Table 115, respectively.

Figure 49 subsections display the following information:

- CO_2 emissions from the cold vents and flares decreased between the 2017 final and 2021 draft inventories. Flares are the major contributor (cold vent contribution is so low that it does not register on the chart as a bar and is represented by the blue value at the bottom of the chart).
- CO_2-E emissions from the cold vents and flares decreased between the 2017 final and 2021 draft inventories. Cold vents were the major contributor.
- CH_4 emissions from cold vents and flares decreased between the 2017 final and 2021 draft inventories. Cold vents were the major contributor.
- N_2O emissions decreased between the 2017 final and 2021 draft inventories and were only generated by flares.

Figure 50 subsections display the following information:

- VOC emissions from cold vents and flares increased between the 2017 final and 2021 draft inventories. Cold vents were the major contributor. Flares VOC emissions increased significantly.
- CO emissions decreased between the 2017 final and 2021 draft inventories and were only generated by flares.
- SO_2 emissions increased drastically between the 2017 final and 2021 draft inventories and were only generated by flares.
- NH_3 Emissions decreased between the 2017 final and 2021 draft inventories and were only generated by flares.
- NO_x emissions decreased between the 2017 final and 2021 draft inventories and were only generated by flares.
- Pb emissions decreased between the 2017 final and 2021 draft inventories and were only generated by flares.

In the following sections, emissions from flares and vents are individually analyzed.

> ***NOTE:*** PM_{10} and $PM_{2.5}$ emissions are not presented in Table 113 and Figure 50 because they were not speciated into filterable or primary in the 2021 draft inventory, as opposed to the 2017 final data. Consequently, comparing the 2021 draft inventory total PM_{10} emissions (from all equipment types) against the 2017 final PM_{10} emissions would not provide a representative picture of the discrepancies between the two reporting years.

Table 113: Flare and vent equipment counts (number) by inventory year with % change

Type	Description	2017 Final	2021 Draft	Difference	% Change
FLA	Combustion Flare	90	114	+ 24	+ 26.7%
VEN	Cold Vent	540	666	+ 126	+ 23.3%

> ***NOTE:*** The equipment counts in Table 113, represent the individual pieces of equipment, not the number of the processes associated with them; if a piece equipment has two processes linked to it, it is still counted as one.

> ***NOTE:*** 2021 draft equipment count includes all equipment reported in the 2021 draft inventory. In some instances, the actual count of emitting pieces of equipment can be less than the reported

because of zeroed-out processes or because some of the pieces of equipment are under non-operational platforms. When needed, the count breakdown is provided in the following sections.

NOTE: In the Table 114 and Table 115 , a "0" indicates that a value of 0 was calculated based on provided activity data, or that the process was zeroed out. A "-" indicates that the equipment type does not emit this pollutant.

Table 114: GHG emissions (tons/year) from flare and vent equipment by inventory year

Equipment Type	CO_2 (GWP = 1) 2017 Final	CO_2 (GWP = 1) 2021 Draft	CH_4 (GWP = 25) 2017 Final	CH_4 (GWP = 25) 2021 Draft	N_2O (GWP = 298) 2017 Final	N_2O (GWP = 298) 2021 Draft	CO_2-E 2017 Final	CO_2-E 2021 Draft
FLA	506,262	387,654	3,184	2,297	8.86	6.61	588,494	447,047
VEN	1,813	1,037	70,488	40,022	-	-	1,764,004	1,001,589

Table 115: Criteria pollutants and precursors emissions (tons/year) from flare and vent equipment by inventory year

Equipment Type	CO 2017 Final	CO 2021 Draft	NOx 2017 Final	NOx 2021 Draft	SO_2 2017 Final	SO_2 2021 Draft	VOC 2017 Final	VOC 2021 Draft	NH_3 2017 Final	NH_3 2021 Draft	Pb 2017 Final	Pb 2021 Draft
FLA	1,362	996	303	227	0.0668	23.7	994	7,526	0.542	0.348	8.46E-5	5.44E-5
VEN	-	-	-	-	-	-	15,732	21,401	-	-	-	-

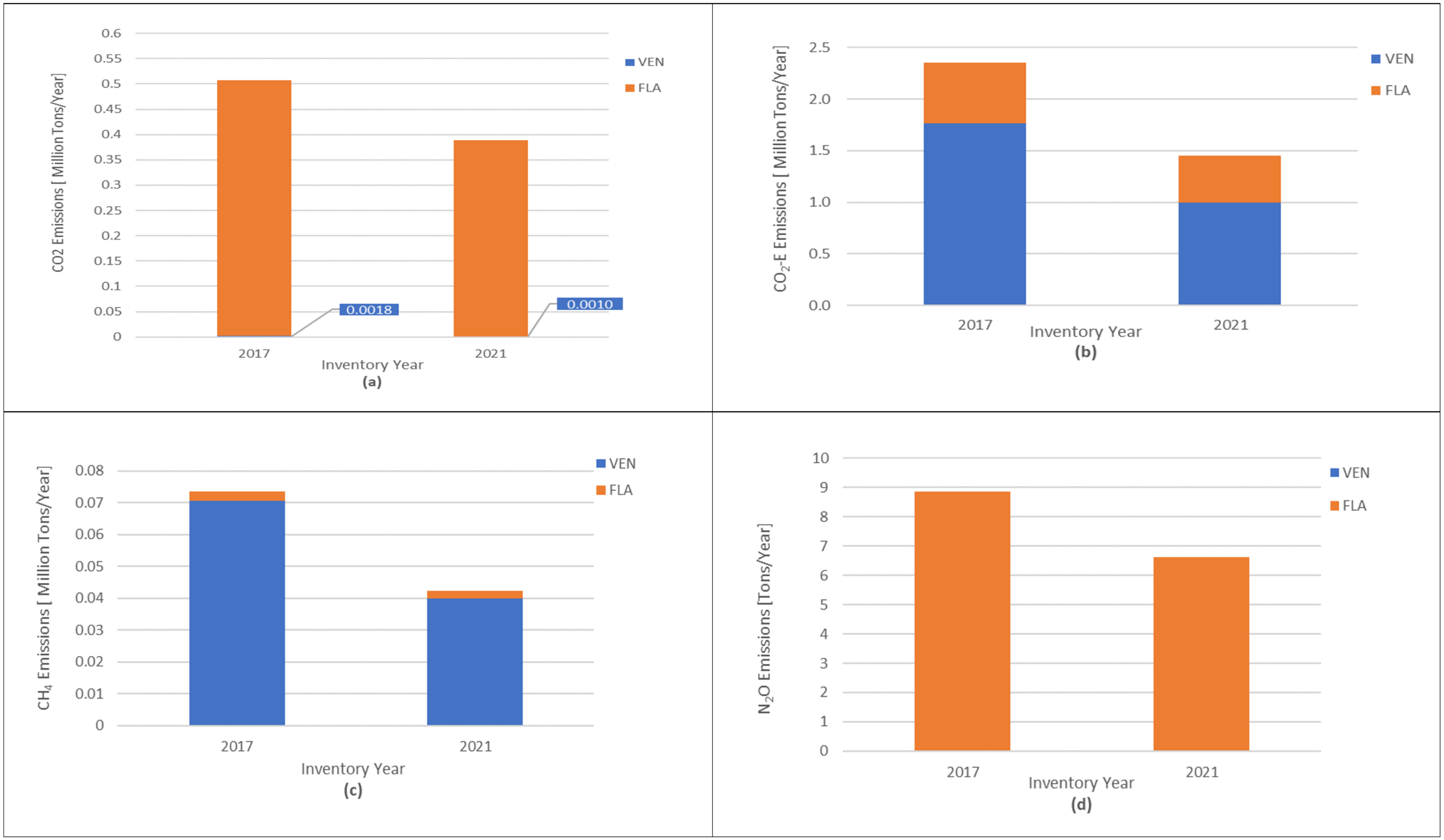


Figure 49: GHG emissions (million tons/year) by flares (in orange) and vents (in blue) for 2017 final and 2021 draft data

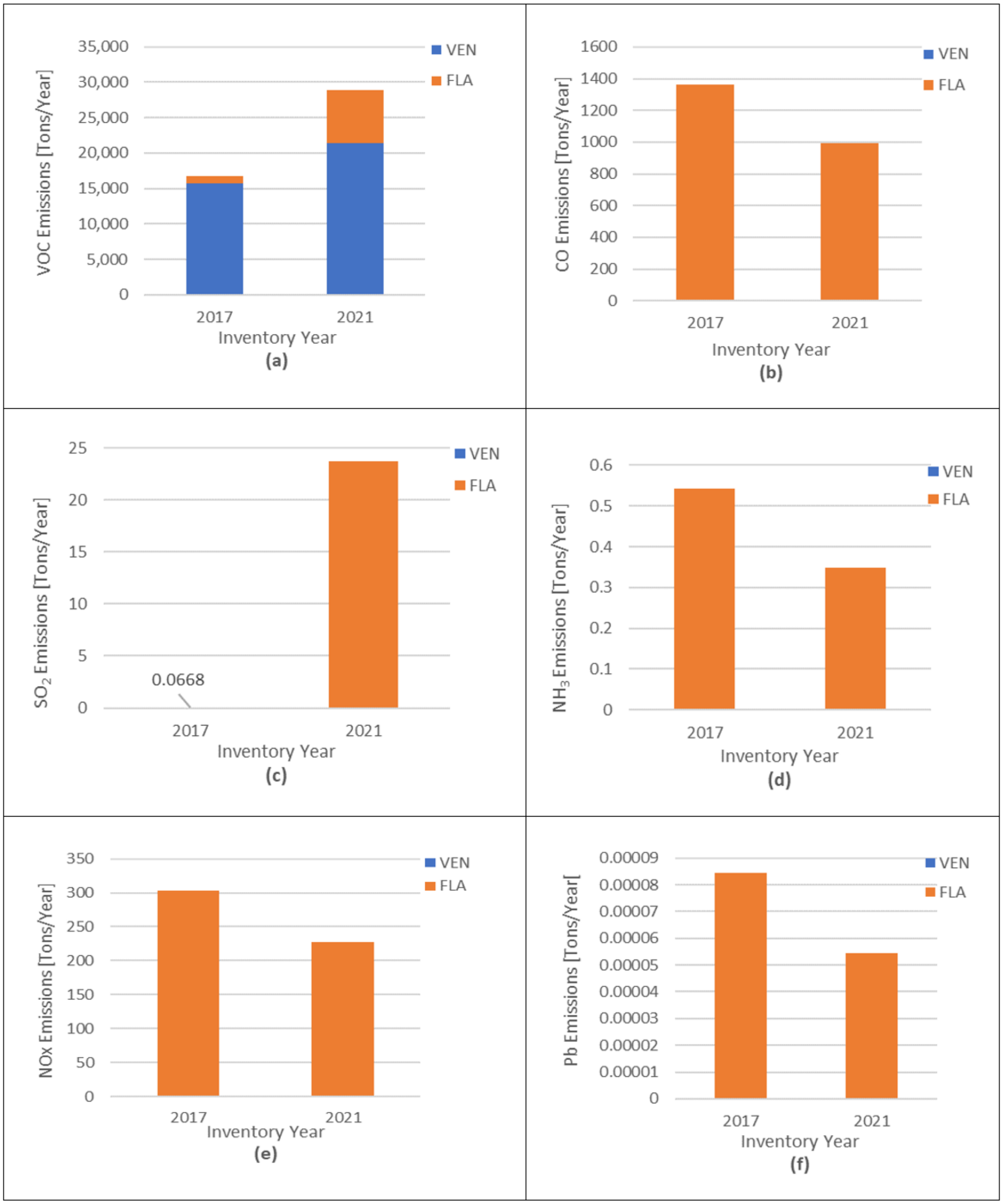


Figure 50: Criteria and precursor emissions (tons/year) by flares (orange) and vents (blue) for 2017 final and 2021 draft data

See Table 84 for equipment type abbreviations key.

6.6.4.1 Combustion Flares (FLA)

The overall volume of flared gas is directly proportional to calculated emissions, and any change in flared gas volume would, in turn, cause a corresponding change in the final calculated emissions. The overall flared gas volume (including both flaring and pilot) increased by 3.41% in the 2021 draft inventory year because of 11.11% increase in the count of emitting flaring processes (Table 116). This increase in the volume of flared gas is expected to cause a similar increase in the flare emissions.

> ***NOTE:*** The percentages shown might be slightly higher or lower depending on other conditions affecting the flaring process.
>
> ***NOTE:*** The total volume of gas flared (including both flaring and pilot) in Table 116 is the corrected throughput after incorporating the corrective action on the anomaly pilot throughput detected in Section 6.5.1.1.1. This is the only corrective action that was included in the 2021 draft inventory. All subsequent corrective actions are included in the revised 2021 inventory to prevent the abnormally high throughput value from obscuring other possible anomalies.

The 2021 draft data presented in Table 117 shows a considerable increase in SO_2 and VOC emissions and a consistent decrease (23–37%) for other pollutant emissions. Both observations are inconsistent with changes observed based on the 3.41% increase in throughput of flared gas. The Team further investigated these inconsistencies of the 2021 draft flares' emissions to discover any possible issues.

Table 116: Comparison of combustion flares throughputs and equipment counts by inventory year with % change (post-corrective action)

Parameter	2017 Final	2021 Draft	% Change
Number of Combustion Flare Emissions Units Reported in the Inventory	90	114	+ 26.67%
Number of **Active Emitting** Flares Emission Units	90 of 90	100 of 114	+ 11.11%
Total Volume of Gas Flared (including both flaring and pilot) [Mscf]	6,264,700	6,478,161	+ 3.41%

Table 117: FLA emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change	Section
CO_2	506,262	387,654	- 118,608	- 23%	-
CH_4	3,184	2,297	- 887	- 28%	-
N_2O	8.86	6.61	- 2.3	- 25%	-
CO_2-E	588,494	447,047	- 141,447	- 24%	-
CO	1,362	996	- 366	- 27%	-
NOx	303	227	- 76	- 25%	-
SO_2	0.0668	23.7	+ 23.6	+ 35,379%	6.6.4.1.1
VOC	994	7,526	+ 6,532.0	+ 657%	6.6.4.1.2
NH_3	0.542	0.348	- 0.2	- 37%	-
Pb	8.46E-05	5.44E-05	- 3.02E-05	- 36%	-

6.6.4.1.1 Investigation on Combustion Flare SO_2 Emissions

SO_2 emissions from combustion flares increased by 35,379% in the 2021 draft inventory (Table 117). Combustion flares in the OCS AQS 2021 draft effort are associated with two processes, flare–flaring and flare–pilot. SO_2 emissions from the combustion flares are only calculated under the flare–flaring process because the flare–pilot processes do not have an EF for SO_2. The SO_2 emissions from flare–flaring process are proportional to the concentration of H_2S in the flare gas.

The 10 highest SO_2 emitting flares by the facility are presented in Table 118. Flare(s) under Facility ID# 20197-1 emitted 22.2 tons of SO_2, representing 93.67% of the total SO_2 emissions from all combustion flares under all facilities in the 2021 draft inventory. Thus, an investigation of this facility's data was conducted to validate the accuracy of the high values of SO_2 emissions from the combustion flare(s).

Facility ID# 20197-1, under company Cantium, LLC, has one combustion flare emission unit (MBF1020) connected to two processes (flare–flaring and flare–pilot). The H_2S concentration was provided in ppm under the flare–flaring process data request tab. It was found that an H_2S concentration value of 20,480 ppm was entered for each month under the data request of the flare–flaring process. A value of 20,480 ppm is considerably higher than the values provided for all the other facilities in the 2021 draft inventory (values ranging between 0 and 4 ppm).

Consequently, the Team contacted the operator of Facility ID# 20197-1 and requested additional information to validate the accuracy of the high concentration of H_2S. The operator confirmed the accuracy of the provided value and explained that it accounts for the AMI emissions within the facility that flared its emissions in flare MBF1020 rather than venting them locally. In OCS AQS, selecting the emissions destination to be anything rather than vented locally will zero out emissions on the process level. Thus, depending on the selection, users are responsible for accounting for the emissions under the flare or cold vent. Therefore, the provided value is accurate to account for the SO_2 emissions from the flare, and no further actions were requested from the operator.

> ***NOTE:*** When the users selected "flared locally" in the 2017 effort, emissions were calculated under the process itself, not under the flare. The SO_2 emissions under the AMI in 2017 final data will be accounted for under flares in 2021 draft data (Section 6.6.5.1).

> ***NOTE*****:** Although the SO_2 emissions were previously analyzed in Section 6.5.5, a substantial increase in flare SO_2 emissions was obscured. In both years, gasoline/diesel engines and turbine generated most of the SO_2 emissions (Figure 19); the emissions produced by the flares were minimal in comparison. This highlights the importance of analyzing the emissions by equipment level and not only through pollutant inventory totals.

Table 118: 2021 draft flare SO_2 emissions (tons/year) by facility: highest 10 emitters

#	Facility ID	Flare SO_2 Emissions [Tons/year]
1	20197-1	22.2
2	2623-1	0.7752
3	70004-1	0.09991348
4	24199-1	0.069873
5	24080-1	0.0522
6	2133-1	0.050607
7	420-1	0.035319
8	2385-1	0.033541
9	2008-1	0.032079
10	24229-1	0.028891

6.6.4.1.2 Investigation on Combustion Flare VOC Emissions

VOC emissions from combustion flares increased by 657% in the 2021 draft inventory (Table 117). The Team used the formulas provided in the *Year 2017 Emissions Inventory Study* (Wilson et al. 2019) to formulate the flare calculators in OCS AQS. VOC emissions from flares calculated using these formulas are proportional to the molecular weight of VOC, which is determined by sales gas compositions. However, when using the activity data from 2017 final data to calculate emissions using the 2021 OCS AQS calculators, calculated emissions were considerably higher than for the 2017 final data using the same activity data. This suggests that other factors, outside the purview of this analysis, affected the 2017 final calculated VOC emissions of combustion flares and are responsible for the discrepancy in emissions.

> ***NOTE***: As part of the QA/QC effort, the Team contacted consultants and confirmed that the formulas used in OCS AQS are accurate and are the same as the ones provided in the *Year 2017 Emissions Inventory Study* document (Wilson et al. 2019).

6.6.4.1.3 Investigation on Combustion Flare GHG, Criteria and Precursor Pollutants Emissions (except SO_2, VOC and Pb)

Although the total flared gas volume increased by 3.4%, the emissions for all pollutants (except SO_2 and VOC) showed a considerable decrease between 2017 final and 2021 draft data. This discrepancy prompted further review of flare activity data in the 2021 draft inventory to determine the cause.

Since the flare gas heating value directly impacts the calculated emissions for all pollutants under the process flare–flaring (except VOC, SO_2, and CH_4), it was a reasonable subject for investigation. Our analysis found that four facilities under BP Exploration & Production Inc. (Table 119) provided relatively low heating values for all months compared to all other facilities. The Team contacted the operators for the facilities listed in the table below to confirm the accuracy of those values, and the operator confirmed that they were mistyped. As a result, those facilities were set to corrective actions to fix the values and recalculate the emissions. Table 120 shows the corrected values.

After the flare gas heating value corrections were made, the following emissions changed between the 2021 draft and final inventory (see also Section 8):

- CO_2: 15,793,642.60 tons (draft) to 5,935,334.81 tons (final)
- CH_4: 95,945.61 tons (draft) to 95,833.721 tons (final)
- N_2O: 121.196 tons (draft) to 121.92 tons (final)
- CO_2-E: 18,228,399.31 tons (draft) to 8,367,509.97 tons (final)
- CO: 28,387.616 tons (draft) to 28,551.228 tons (final)
- NO_x: 34,651.346 tons (draft) to 34,660.535 tons (final)
- NH_3: 4.614 tons (draft) to 4.442 tons (final)
- Pb: 0.0056 tons (draft) to 0.0056 tons (final)

> ***NOTE:*** The corrective action requested in this section and other corrections made throughout the document collectively resulted in the changes in emissions mentioned above.

Table 119: Relatively low flare gas heating value (Btu/scf) in FLA emission units in the 2021 draft data

Company Name	Facility ID	Emission Unit	Process	2021 Draft Flare Gas Heating Value [Btu/scf]
BP Exploration & Production Inc.	1001-1	FL-01	FL-NPf	300
BP Exploration & Production Inc.	1101-1	FL-01	FL-NPf	300
BP Exploration & Production Inc.	1215-1	FL-01	FL-NPf	300
BP Exploration & Production Inc.	1223-1	FL-01	FL-NPf	300

Table 120: Revised flare gas heating values (Btu/scf) in the 2021 draft data

Company Name	Facility ID	Emission Unit	Process	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BP Exploration & Production Inc.	1001-1	FL-01	FL-NPf	1,136	1,129	1,136	1,145	1,150	1,154	1,196	1,194	1,196	1,199	1,193	1,193
BP Exploration & Production Inc.	1101-1	FL-01	FL-NPf	1,470	1,485	1,483	1,462	1,457	1,485	1,148	1,482	1,490	1,488	1,481	1,484
BP Exploration & Production Inc.	1215-1	FL-01	FL-NPf	1,270	1,272	1,265	1,258	1,267	1,274	1,249	1,264	1,268	1,272	1,275	1,273
BP Exploration & Production Inc.	1223-1	FL-01	FL-NPf	1,136	1,129	1,136	1,145	1,150	1,154	1,196	1,194	1,196	1,199	1,193	1,193

6.6.4.1.4 Investigation on Combustion Flare Pb Emissions

Pb is emitted only from flare–pilot processes, and the observed 36% decrease in the Pb flares emissions results from the discrepancy in the Pb flare–pilot EF discussed in Section 5.1.2.

6.6.4.2 Cold Vents (VEN)

The volume of vented gas decreased by 38.2% because of the 31.11% decrease in the count of emitting cold vents (Table 121). Since the pollutant emissions are directly proportional to the volume of vented gas, this decrease should lead to the corresponding decrease in emissions. This trend was observed in CO_2 and CH_4 (as well as calculated CO_2-E), which decreased by 43%, but not in the VOC emissions, which increased by 36% (Table 122). Based on these observations, cold vent VOC emissions were investigated further to determine the possible reasons.

Table 121: Comparison of cold vent throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Cold Vent Processes Reported in the Inventory	540	666	+ 23.33%
Number of **Active Emitting** Cold Vent Processes	540 of 540	372 of 666	- 31.11%
Volume of Vented Gas to Active Emitting Processes [Mscf]	3,691,354	2,282,582	- 38.16%

6.6.4.2.1 Investigation on Cold Vent VOC Emissions

As shown in Table 122, VOC emissions from cold vents increased by 36% in the 2021 inventory.

Table 122: Cold vent emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CO_2	1,813	1,037	- 776	- 43%
CH_4	70,488	40,022	- 30,466	- 43%
CO_2-E	1,764,004	1,001,589	- 762,415	- 43%
VOC	15,732	21,401	+ 5,669	+ 36%

VOC emissions from cold vents are calculated in OCS AQS using the concentration of VOC in the vented gas, which is an operator-specified value under the data request tab for the cold vents. The Team analyzed all provided values of VOC concentration in the 2021 draft inventory to highlight any anomalously high values that might have caused this increase in the 2021 draft emissions.

Under described operations, the vented gas comprised mainly CH_4 (approximately 90%) and VOCs (approximately 10%, which equates to 100,000 ppmv). Table 123 shows that 84 emission units have VOC concentrations considerably higher (approximately 10 times) than expected. While the value is provided once for each emission unit in the table, it was specified for each of the 12 months for those emission units in the 2021 draft emissions inventory, compounding the effect. The Team contacted the operators of the facilities with those anomalous values and requested clarification. Operators confirmed that those values were incorrectly entered and requested corrective actions to fix them accordingly and recalculate emissions. Therefore, those high values of VOC concentrations were the reason for the observed increase in the vent VOC emissions in the 2021 draft inventory. "Post-Corrective Action Concentration of VOC in the Vented Gas [ppmv]" column in Table 123 shows the corrected values provided by the operators. After corrective action, VOC emissions from cold vents decreased from 21,401 tons in the draft to 12,570 tons in the 2021 final inventory (Section 8).

Table 123: Facilities with considerably high concentration of VOC in the vented gas (ppmv) in the 2021 draft data

#	Company Name	Facility ID	Emission Unit	Pre- Corrective Action Concentration of VOC in Vented Gas [ppmv]	Post- Corrective Action Concentration of VOC in Vented Gas [ppmv]
1	GOM Shelf LLC	20575-1	SCRUBBER	947,560	9,476
2	Fieldwood Energy, LLC	2343-1	LPVNT	992,590	9,926
3	Fieldwood Energy, LLC	22224-1	ATMVENT	986,260	9,863
4	Fieldwood Energy, LLC	22224-1	VNTSCRB	986,260	9,863
5	Fieldwood Energy, LLC	23563-1	ATMVENT	984,110	9,841
6	Fieldwood Energy, LLC	23563-1	V-01	984,110	9,841
7	Fieldwood Energy, LLC	23196-1	V-01	982,640	9,826
8	Fieldwood Energy, LLC	687-1	ATMVENT	982,540	9,825
9	Fieldwood Energy, LLC	10071-1	VENT	980,450	9,805
10	Fieldwood Energy, LLC	23162-1	VNTBM	978,400	9,784
11	Fieldwood Energy, LLC	23162-1	VNTSCRB2	978,400	9,784
12	Fieldwood Energy, LLC	23162-1	VNTSCRB1	978,400	9,784
13	Fieldwood Energy, LLC	20724-2	LPSCRUB	975,970	9,760
14	Fieldwood Energy, LLC	20114-1	VNTSCRB	975,370	9,754
15	Fieldwood Energy, LLC	23415-1	ATMVENT	975,370	9,754
16	Fieldwood Energy, LLC	23415-1	VNTSCRUB	975,370	9,754
17	Fieldwood Energy, LLC	24159-1	VNTSCRB	975,370	9,754
18	Fieldwood Energy, LLC	410-1	SCRUBBER	975,370	9,754
19	Fieldwood Energy, LLC	22087-1	VNTBM	973,960	9,740
20	Fieldwood Energy, LLC	22087-1	VNTSCRB	973,960	9,740
21	Fieldwood Energy, LLC	23321-1	VNTBM-1	971,910	9,719
22	Fieldwood Energy, LLC	23321-1	VNTSCRB	971,910	9,719
23	Fieldwood Energy, LLC	20630-3	FLRKO	970,110	9,701
24	Fieldwood Energy, LLC	23083-1	ATMVNT	967,310	9,673
25	Fieldwood Energy, LLC	23083-1	VNTSCRB	967,310	9,673
26	Fieldwood Energy, LLC	2430-1	VNTSCRB	967,310	9,673
27	Fieldwood Energy, LLC	686-1	HPSCRUBB	967,040	9,670
28	Fieldwood Energy, LLC	686-1	ATMVNT	967,040	9,670
29	Fieldwood Energy, LLC	686-1	LPSCRUB	967,040	9,670
30	Fieldwood Energy, LLC	20341-1	VNTSCRB	965,970	9,660
31	Fieldwood Energy, LLC	23402-1	VNTSCRB	965,970	9,660
32	Fieldwood Energy, LLC	228-1	VNTSCRB1	965,160	9,652
33	Fieldwood Energy, LLC	228-1	VNTSCRB2	965,160	9,652
34	Fieldwood Energy, LLC	1027-1	VNTSCRB	964,190	9,642
35	Fieldwood Energy, LLC	1027-1	VNTBM	964,190	9,642
36	Fieldwood Energy, LLC	21860-1	VNTSCRB	963,410	9,634
37	Fieldwood Energy, LLC	21864-1	VNTSCRB	963,410	9,634
38	Fieldwood Energy, LLC	21864-3	VNTSCRB	963,410	9,634

#	Company Name	Facility ID	Emission Unit	Pre- Corrective Action Concentration of VOC in Vented Gas [ppmv]	Post- Corrective Action Concentration of VOC in Vented Gas [ppmv]
39	Fieldwood Energy, LLC	22335-1	VNTSCRB	963,410	9,634
40	Fieldwood Energy, LLC	23800-1	ATMVNT	963,030	9,630
41	Fieldwood Energy, LLC	23800-1	VNTSCRB	963,030	9,630
42	Fieldwood Energy, LLC	2247-1	VNTBM	961,370	9,614
43	Fieldwood Energy, LLC	2247-1	VNTSCRB	961,370	9,614
44	Fieldwood Energy, LLC	26050-2	ATMVNT	955,790	9,558
45	Fieldwood Energy, LLC	26050-2	VNTSCRB	955,790	9,558
46	Fieldwood Energy, LLC	22286-1	VENTSCRB	954,270	9,543
47	Fieldwood Energy, LLC	23240-1	VNTSCRB	953,750	9,538
48	Fieldwood Energy, LLC	23240-1	ATMVNT	953,750	9,538
49	Fieldwood Energy, LLC	23240-1	HPVENT	953,750	9,538
50	Fieldwood Energy, LLC	22707-3	ATMVNT	951,410	9,538
51	Fieldwood Energy, LLC	22707-3	VNTSCRB	951,410	9,514
52	Fieldwood Energy, LLC	22954-1	LPSCRUB	951,410	9,514
53	Fieldwood Energy, LLC	21580-1	VNTSCRB	951,050	9,511
54	Fieldwood Energy, LLC	22421-1	FLRSCRUB	950,560	9,506
55	Fieldwood Energy, LLC	21590-1	VNTSCRUB	948,870	9,489
56	Fieldwood Energy, LLC	21778-1	VNTSCRB	948,870	9,489
57	Fieldwood Energy, LLC	20375-1	ATMSCRUB	921,550	9,216
58	Fieldwood Energy, LLC	20375-1	VNTSCRUB	921,550	9,216
59	Fieldwood Energy, LLC	20375-2	ATMVNT	921,550	9,216
60	Fieldwood Energy, LLC	20375-2	VNTSCRB	921,550	9,216
61	Fieldwood Energy, LLC	20376-1	ATMVNT	921,550	9,216
62	Fieldwood Energy, LLC	20376-1	VNTSCRB	921,550	9,216
63	Fieldwood Energy, LLC	21739-2	LPVENT	921,200	9,212
64	Fieldwood Energy, LLC	22046-1	VNTSCRB	963,410	9,673
65	Fieldwood Energy Offshore LLC	20285-1	LPVENT	991,140	9,911
66	Fieldwood Energy Offshore LLC	20285-1	ATMVENT	991,140	9,911
67	Fieldwood Energy Offshore LLC	20285-2	HPVENT	991,140	9,911
68	Fieldwood Energy Offshore LLC	20285-3	HPVENT	991,140	9,911
69	Fieldwood Energy Offshore LLC	20319-1	V-01	991,140	9,911
70	Fieldwood Energy Offshore LLC	20319-1	V-02	991,140	9,911
71	Fieldwood Energy Offshore LLC	20319-1	V-03	991,140	9,911
72	Fieldwood Energy Offshore LLC	20491-1	ATMVENT	991,140	9,911
73	Fieldwood Energy Offshore LLC	20491-1	UW-VENT	991,140	9,911
74	Fieldwood Energy Offshore LLC	21169-1	V-01	991,140	9,911
75	Fieldwood Energy Offshore LLC	21169-1	V-02	991,140	9,911
76	Fieldwood Energy Offshore LLC	27021-1	V-01	990,700	9,907
77	Fieldwood Energy Offshore LLC	23552-1	ATMVENT	987,500	9,875
78	Fieldwood Energy Offshore LLC	319-1	V-01	979,740	9,797

#	Company Name	Facility ID	Emission Unit	Pre- Corrective Action Concentration of VOC in Vented Gas [ppmv]	Post- Corrective Action Concentration of VOC in Vented Gas [ppmv]
79	Fieldwood Energy Offshore LLC	319-1	V-02	979,740	9,797
80	Fieldwood Energy Offshore LLC	1266-1	VNTSCR	978,470	9,797
82	Fieldwood Energy Offshore LLC	27017-1	V-01	978,470	9,785
83	Walter Oil & Gas Corporation	70029-1	V-02	143,460	53,440
84	Walter Oil & Gas Corporation	70029-1	V-03	143,460	53,440
85	Walter Oil & Gas Corporation	2606-1	V-01	95,320	43,130
86	Walter Oil & Gas Corporation	2606-1	V-02	95,320	43,130

6.6.5 Emissions by Non-Combustion Equipment

This section compares 2017 final and 2021 draft emissions from non-combustion equipment to investigate discrepancies and identify the underlying possible causes.

Table 124 compares the non-combustion equipment count in 2017 final and 2021 draft data. Table 125 and Table 126 present a breakdown of the GHG and criteria pollutants and precursor emissions from all equipment types in 2017 final and 2021 draft data. Figure 51 and Figure 52 are the visual representations for Table 125 and Table 126, respectively.

Figure 51 subsections display the following information:

- CO_2 emissions decreased between 2017 final and 2021 draft inventories, and the biggest contributors were PNE and PRE.
- CO_2-E emissions decreased between 2017 final and 2021 draft inventories, and the biggest contributors were FUG and PNE.
- CH_4 emissions decreased between 2017 final and 2021 draft inventories, and the biggest contributors were FUG and PNE.
- N_2O emissions were not generated from all non-combustion equipment.

Figure 52 subsections display the following information:

- VOC emissions decreased between 2017 final and 2021 draft inventories, and the biggest contributor was FUG.
- SO_2 emissions from non-combustion equipment were attributed exclusively to AMI in the 2017 final inventory, and no SO_2 emissions were recorded under the non-combustion equipment in the 2021 draft inventory.

  NOTE: Figure 52 has subsection for VOC and SO_2 only because other criteria pollutants are not emitted from all non-combustion equipment (see Table 126)

The following sections individually analyze emissions from each non-combustion equipment types.

Table 124: Non-combustion equipment count (number) by inventory year with % change

#	Type	Description	2017 Final	2021 Draft	Difference	% Change
1	AMI	Amine Unit	4	4	0	0%
2	FUG	Fugitives – Total components	34,999,206	24,391,952	- 10,607,254	- 30%
3	GLY	Glycol Dehydrator	176	187	+ 11	+ 6%

#	Type	Description	2017 Final	2021 Draft	Difference	% Change
4	LOA	Loading Operation	1	1	0	0%
5	LOS	Losses from Flashing	400	405	+ 5	+ 1.25%
6	MUD	Mud Degassing	7	16	+ 9	+ 129%
7	PNE	Pneumatic Pump	2,757	3,265	+ 508	+ 18%
8	PRE	Pneumatic Controller	1,703	1,619	- 84	- 5%
9	STO	Storage Tank	336	298	- 38	-11%
		Total	**8,583**	**9,413**	**830**	**+9.7%**

NOTE: The equipment counts in Table 124 represent the individual pieces of equipment, not the number of the processes associated with them; if a piece equipment has two processes linked to it, it is still counted as one.

NOTE: The fugitive count presented in Table 124 is the total number of fugitive components, not the count of fugitive pieces of equipment; a piece of fugitive equipment has multiple components.

NOTE: The 2021 draft equipment count includes all equipment reported in the 2021 draft inventory. In some instances, the actual count of emitting pieces of equipment is less than the reported because of zeroed-out processes or because some of the pieces of equipment are under non-operational platforms. When needed, the count breakdown is provided in the following sections.

Table 125: GHG emissions (tons/year) from non-combustion equipment by inventory year

Equipment Type	CO_2 (GWP = 1) 2017 Final	CO_2 (GWP = 1) 2021 Draft	CH_4 (GWP = 25) 2017 Final	CH_4 (GWP = 25) 2021 Draft	N_2O (GWP = 298) 2017 Final	N_2O (GWP = 298) 2021 Draft	CO_2-E 2017 Final	CO_2-E 2021 Draft
AMI	140	0	3.37	0	-	-	224	0
FUG	-	-	54,239	28,337	-	-	1,355,971	708,420
GLY	-	-	557	325	-	-	13,914	8,130
LOA	-	-	-	-	-	-	-	-
LOS	93.7	28.6	4,033	1,231	-	-	100,922	30,807
MUD	0.796	1.22	85.9	131	-	-	2,147	3,283
PNE	537	270	28,559	12,320	-	-	714,508	308,278
PRE	377	140	15,470	6,329	-	-	387,138	158,372
STO	-	-	551	187	-	-	13,784	4,677

Table 126: Criteria pollutants and precursors emissions (tons/year) from non-combustion equipment by inventory year

Equipment Type	CO 2017 Final	CO 2021 Draft	NO_x 2017 Final	NO_x 2021 Draft	SO_2 2017 Final	SO_2 2021 Draft	VOC 2017 Final	VOC 2021 Draft	NH_3 2017 Final	NH_3 2021 Draft	Pb 2017 Final	Pb 2021 Draft
AMI	-	-	-	-	22.7	0	0.0647	-	-	-	-	-
FUG	-	-	-	-	-	-	13,408	7,176	-	-	-	-
GLY	-	-	-	-	-	-	851	0	-	-	-	-
LOA	-	-	-	-	-	-	70.1	-	-	-	-	-
LOS	-	-	-	-	-	-	181	55.4	-	-	-	-
MUD	-	-	-	-	-	-	35.6	0	-	-	-	-
PNE	-	-	-	-	-	-	3,370	1,622	-	-	-	-
PRE	-	-	-	-	-	-	2,222	890	-	-	-	-
STO	-	-	-	-	-	-	556	189	-	-	-	-

NOTE: In Table 125 and Table 126, "0" indicates that a value of 0 was calculated based on provided activity data, or that the process was zeroed out. A "-" indicates that the equipment type does not emit this pollutant.

NOTE: PM_{10} and $PM_{2.5}$ are not in Table 126 because non-combustion pieces of equipment do not emit PM_{10} and $PM_{2.5}$ emissions.

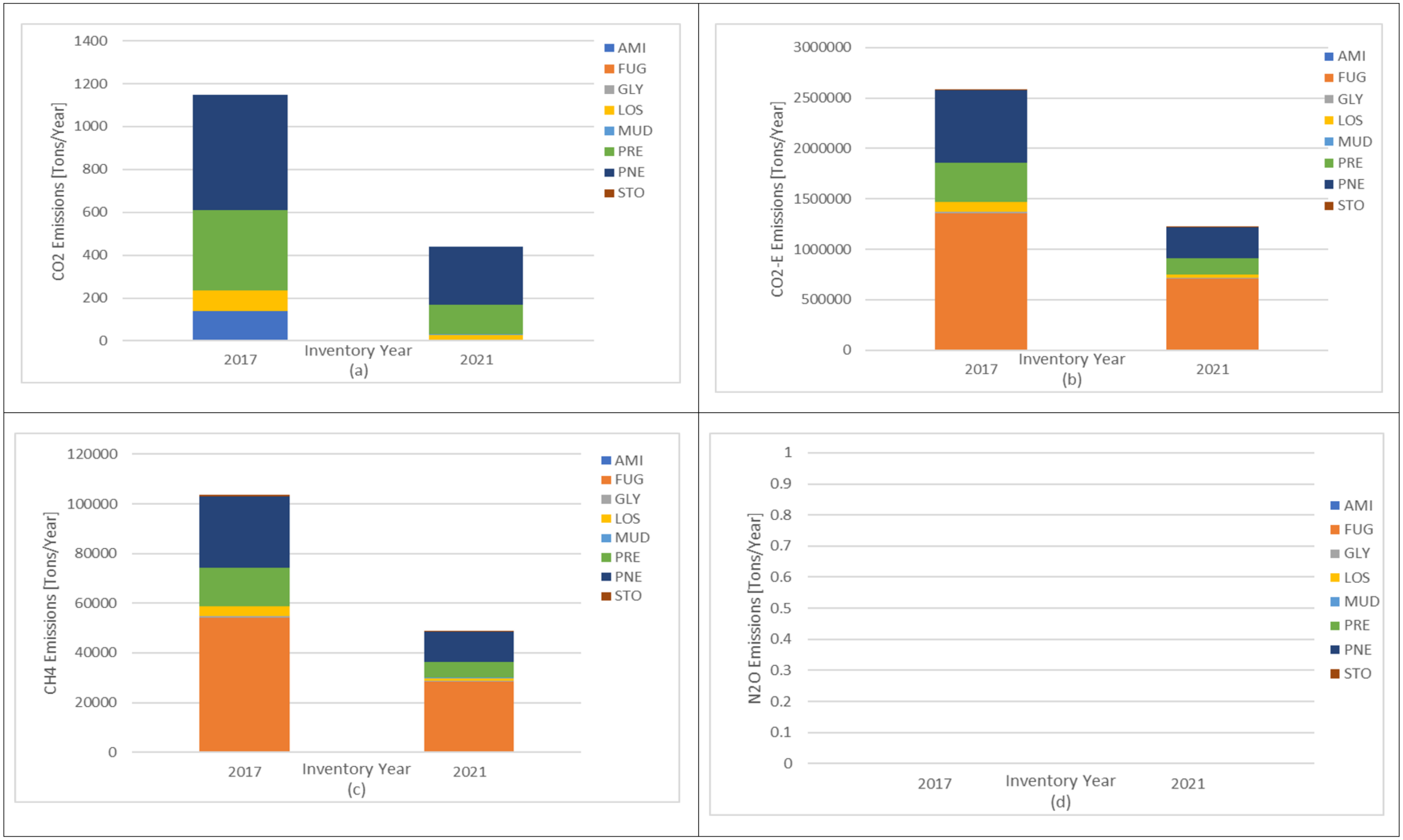


Figure 51: GHG emissions (tons/year) by non-combustion equipment for 2017 final and 2021 draft data

See Table 124 for equipment type abbreviations key.

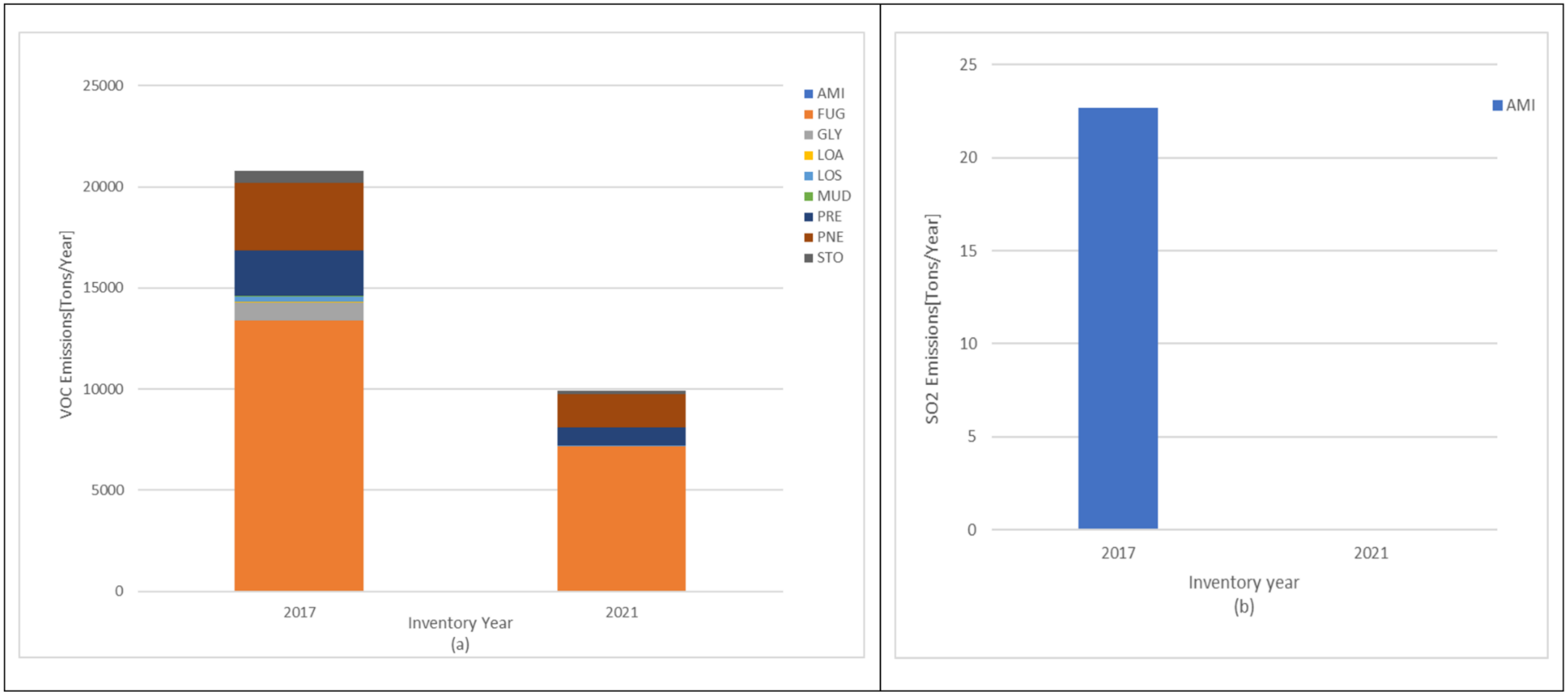


Figure 52: Criteria and precursor emissions (tons/year) by non-combustion equipment for 2017 final and 2021 draft data

See Table 124 for equipment type abbreviations key.

6.6.5.1 Amine Units (AMI)

Although the total count of reported AMI emissions remained the same in the 2021 draft inventory (four emissions units in both inventory years) (Table 124), no emissions were attributed to these four emission units in the 2021 draft emissions inventory (Table 125 and Table 126).

The Team conducted a rigorous analysis on the 2021 draft AMI data to investigate the underlying reason for no emissions from those four AMI in the 2021 draft inventory. It was determined that the emissions from those AMI were not vented locally (three were flared remotely and one was routed to the system). In OCS AQS, the selection of non-vented locally emissions destination zeroes out emissions at the emission unit level, and the operators must report the emissions under flares or vents, depending on the selection of the emissions destination. In the 2017 final inventory, emissions from AMI were reported under the emission units that generated them regardless of whether they were vented or flared locally. Therefore, the different approaches of handling non-vented locally emissions in 2017 final and 2021 draft caused this discrepancy.

> ***NOTE:*** In Table 127, "0" indicates that a value of 0 was calculated based on provided activity data, or that the process was zeroed out. A "-" indicates that no data regarding this pollutant was provided and the emissions were not calculated.

Table 127: Amine unit emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CO_2	140	0	- 140	- 100%
CH_4	3.37	0	- 3.37	- 100%
CO_2-E	224	0	- 224	- 100%
SO_2	22.7	-	- 22.7	N/A
VOC	0.0647	-	- 0.0647	N/A

6.6.5.2 Fugitives (FUG)

The total count of FUG components decreased by 30% in the 2021 draft inventory (to 24,391,952 components) (Table 124). However, only 22,953,993 of 24,391,952 were active and emitting, while the remaining components belonged to non-operating facilities or were reported as zero emissions processes). Table 128 provides a breakdown of the count of fugitive components and shows that the emitting components decreased by 34.4% in the 2021 draft inventory. Although this data suggests that the decrease in the FUG components contributed to the decrease in emissions, Table 129 shows that the emissions decreased between 46.5% and 47.8%, which is higher than the 34.4% expected if FUG component count were the only factor.

Total FUG hydrocarbon emissions are calculated based on equipment component types, equipment counts, and stream type (gas, light oil, heavy oil, natural gas liquid, water/oil, or water/oil/gas). CH_4 and VOC emissions from fugitives are calculated from total hydrocarbons emissions based on their composition fractions within the stream type. In the OCS AQS 2021 draft effort, all EFs and fractions are pre-defined for users based on the values provided in Tables 4-14 and 4-15 of the *Year 2017 Emissions Inventory Study* (Wilson et al. 2019).

Analysis of the 2017 final data showed that users had the flexibility to provide the VOC weight percent of fugitives. Therefore, unlike the 2021 draft inventory, different fractions were used within the same stream type and component type. This inconsistency in identifying the VOC fractions can impact the overall calculated emissions and cause the discrepancies in the emissions calculations between the two inventory years.

Table 128: Comparison of fugitive component counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Fugitive Components Reported in the Inventory	34,999,206	24,391,952	- 30 %
Number of **Active Emitting** Fugitive Components	34,999,206 of 34,999,206	22,953,993 of 24,391,952	- 34.4%

Table 129: Fugitive emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	%Change
CH_4	54,239	28,337	- 25,902	- 47.8%
CO_2-E	1,355,971	708,420	- 647,551	- 47.8%
VOC	13,408	7,176	- 6,232	- 46.5%

6.6.5.3 Glycol Dehydrator (GLY)

The total count of the GLY emission units increased by 6% (see Table 124), but Table 125 and Table 126 show that the amount of the GLY emitted pollutants actually decreased by a considerable amounts in 2021. This discrepancy prompted further investigation of the GLY emission units to determine the reason.

The investigation found that 106 GLY emission units (almost 57% of GLY emission units) were zeroed out in the 2021 draft inventory. Therefore, 2021 draft emissions included reporting from only 81 GLY emission units, effectively decreasing the count of emitting GLY emission units by almost 54% (Table 130). This decrease led to the observed decrease in the GLY emissions from 2017 final to 2021 draft data. A list of the 106 zeroed-out GLY processes is provided in Appendix E.

> ***NOTE:*** It is essential to mention that, for the first time, the operators were responsible for running the GLYCalc model to estimate emissions in the 2021 inventory.

CH_4 and CO_2-E emissions decreased by a reasonable percentage resulting from the decrease in the total count of the emitting GLY units (Table 131). However, VOC emissions decreased by 100% (no VOC emissions were reported in 2021). Although OCS AQS calculates GLY emissions based on the emission rates provided by the operators, the system cannot validate that these are latest and correct (Section 6.5.13.2.1). Users import those emissions, and OCS AQS has no control over their estimation methodologies or values. Therefore, discrepancies might occur depending on the quality of the imported data. The absence of VOC emissions may be explained by users not importing VOC emission rates in 2021 draft data.

Table 130: Glycol dehydrator equipment count (numbers) by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Count of GLY Emission Units	176	187	+ 6%
Count of GLY Emission Units – not zeroed out	176	81	- 53.97%

Table 131: Glycol dehydrator emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CH_4	557	325	- 232	- 42%
CO_2-E	13,914	8,130	- 5,784	- 42%
VOC	851	-	- 851	-100%

NOTE: "-" indicates that no data regarding this pollutant was provided and emissions were not calculated.

6.6.5.4 Loading Operation (LOA)

LOA emitted pollutants from loading operations are calculated in OCS AQS for the 2021 effort using calculator LOA-M01R. Users are requested to provide the monthly throughput, as well as the tanks specifications and the material conditions, under the data request fields in OCS AQS to calculate the emissions. Only one loading operation process was reported in both 2017 final and 2021 draft inventory years (Table 124). VOC is the only pollutant emitted from LOA processes, and Table 132 compares 2021 draft and 2017 final LOA emissions for VOC. The analysis showed that the 2021 draft LOA emissions are zero because the emissions were routed to system in 2021 draft, whereas they were vented locally in the 2017 final data. This variation in emission destination caused the 100% decrease of LOA emissions in 2021 draft data (Table 132).

Although the 2021 draft emissions are zeroed out on the process level (routed to system), the Team compared the provided throughputs to the ones reported in the 2017 final data to ensure data quality. The total annual throughput decreased only by 3.7%, which indicates that there are no issues in the 2021 draft reported throughputs (Table 133).

Table 132: Loading operation emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
VOC	70.1	0	- 70.1	- 100%

Table 133: Loading operation throughput (bbl/year) by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Throughput Volume [bbl]	4,403,776.70	4,241,933.00	- 3.7%

6.6.5.5 Losses from Flashing (LOS)

OCS AQS calculated LOS in the 2021 effort using calculator LOS-M01. Users provide data related to the throughput and conditions of the material being flashed in the OCS AQS data request fields to calculate emissions. Only four additional LOS processes (1.25%) were added to the 2021 draft inventory (405 losses from flashing processes in the 2021 draft inventory) (Table 124). However, 244 of 405 processes were active and emitting; the remaining processes belonged to non-operating facilities or were reported as zero emissions processes. The emitting processes decreased by 39% in the 2021 draft inventory, which resulted in 44% decrease in total throughput to the LOS processes (Table 134).

Table 134: Comparison of losses from flashing throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Losses from Flashing Processes Reported in the Inventory	400	405	+ 1.25%
Number of **Active Emitting** Losses from Flashing Processes	400 of 400	244 of 405	- 39%
Throughput Volume to **Active Emitting** Losses from Flashing Processes [bbl]	155,086,403.62	86,492,832.68	- 44.23%

Therefore, any noticeable discrepancies between emissions from LOS emission units should be attributed to discrepancies in the throughput or other factors. The emissions from LOS emission units decreased by almost 70% in the 2021 draft data (Table 135). This decrease in throughput (resulting from the decrease in the count active emitting LOS processes) is largely responsible for the decrease in emissions. Other factors, such as pressure and temperature, also could affect calculated emissions from LOS emission units and are likely responsible for further reducing the emissions; however, at the time of this analysis, the Team did not have access to this 2017 data.

Table 135: Losses from flashing emissions (tons/year) by Inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CH_4	4,033	1,231	- 2,802	- 69.5%
CO_2	93.7	28.6	- 65.1	- 69.5%
CO_2-E	100,922	30,807	- 70,115	- 69.5%
VOC	181	55.4	- 125.6	- 69.4%

6.6.5.6 Mud Degassing (MUD)

Total count of MUD emission units increased by 129% in the 2021 draft inventory (Table 124), and the amount of emitted pollutants also increased in the 2021 draft data (Table 125 and Table 126). It was expected that the emissions from MUD emission units would increase by high percentages due to the increase in the total count of reported MUD emission units. The Team also looked at the number of drilling days (Table 137), which increased along with the count of the MUD emission units. These factors resulted in an increase in the reported emissions from MUD emission units.

In addition, days per month of drilling are proportionally correlated to the MUD emissions (Section 3.2.9). Therefore, if the days of drilling increased in 2021 draft data, this would explain the increase in the 2021 draft MUD emissions. Different types of mud have different EFs (Table 25), and it was necessary to categorize the days of drilling and their corresponding MUD emissions based on the mud type to compare the 2017 final and 2021 draft emissions against the days per month of drilling. Days of drilling with water-based mud increased by 29% in the 2021 draft data (Table 136), which is consistent with the increase in emissions from drilling with water-based mud (Table 137). Similarly, a 153% increase in days of drilling with synthetic/oil-based mud caused a similar increase of emissions (between 151 and 155%) from drilling with synthetic/oil-based mud (Table 137).

Therefore, the increase in drilling days directly resulted in increased emissions from MUD emission units. No further investigations or corrective actions were required for the 2021 draft MUD emission units.

Table 136: Drilling days (number) by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Days per Month of Drilling with Water-based Mud	242	311	+ 29%
Days per Month of Drilling with Synthetic / Oil-based Mud	262	663	+ 153%
Total Days per Month of Drilling with Mud	504	974	+ 93%

Table 137: Mud degassing emissions (tons/year) by mud type by inventory year with % change

Mud Type	Pollutant	2017 Final	2021 Draft	Difference	%Change
Water-based Muds	CH_4	69.02	88.73	19.71	+ 28.55%
Water-based Muds	CO_2	0.640	0.823	0.183	+ 28.50%
Water-based Muds	CO_2-E	1,724	2,219	495	+ 28.71%
Synthetic / Oil-based Muds	CH_4	16.81	42.27	25.46	+ 151.47%
Synthetic / Oil-based Muds	CO_2	0.156	0.397	0.241	+ 155.10%
Synthetic / Oil-based Muds	CO_2-E	421	1,064	643	+ 152.91%

NOTE: Synthetic and oil-based mud drilling days and emissions were combined in Table 136. Table 137 identifies that they have the same EF, therefore separating them would not reveal any additional information.

6.6.5.7 Pneumatic Pump (PNE)

OCS AQS calculated PNE emissions in the 2021 effort using calculator PNE-M01R. Users provide the operational hours of the pumps, as well as their fuel usage rate, in the OCS AQS data request fields to calculate emissions. The 2021 draft inventory included 508 additional PNE processes, totaling to 3,265 PNE processes in the 2021 draft inventory (Table 124). However, 1,544 of 3,265 processes were active and emitting; the remaining processes belonged to non-operating facilities or were reported as zero emissions processes. Emitting PNE processes decreased by 43.6% in the 2021 draft inventory, which resulted in 68.6% decrease in total fuel usage by the PNE processes (Table 138).

Table 138: Comparison of pneumatic pump throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Pneumatic Pumps Processes Reported in the Inventory	2,757	3,265	+ 18.4%
Number of **Active Emitting** Pneumatic Pumps Processes	2,757 of 2,757	1,554 of 3,265	- 43.6%
Total Fuel Usage Per Device [scf/month] by Active Emitting Pneumatic Pumps Processes	1,593,203,534	499,828,037	- 68.6%

The amount of emissions generated by the PNE emission units is directly proportional to the fuel usage (throughput), and any change in this value would have an effect on the calculated emissions. The approximately 70% decrease in the fuel usage by emitting PNE processes is similar enough to the decrease in PNE emissions (Table 139) that it can be concluded that this reduction in throughput is the major cause in the change in emissions between 2017 final and 2021 draft data. Based on these conclusions, no further assessments were conducted on PNE processes.

NOTE: The six-monthly records of erroneous PNE hours of operation in month that were identified in Section 4.6.2.4 and corrected by operators also impacted PNE emissions.

Table 139: Pneumatic pump emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CH_4	28,559	12,320	- 16,239	- 56.9%
CO_2	537	270	- 267	- 49.7%
CO_2-E	714,508	308,278	- 406,230	- 56.9%
VOC	3,370	1,622	- 1,748	- 51.9%

6.6.5.8 Pneumatic Controller (PRE)

Although the total count of the PRE emission units (controllers) decreased only by 5% in the 2021 draft inventory (1,619 PRE processes were reported in the 2021 draft inventory), only 856 of 1,619 PRE processes were active and emitting (Table 124); the remaining processes belonged to non-operating facilities or were reported as zero emissions processes. Emitting PRE processes decreased by 49.7% in the 2021 draft inventory, which resulted in 57.8% decrease in total fuel usage by the PRE processes (Table 140).

Table 140: Comparison of pneumatic controller throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Pneumatic Controllers Processes Reported in the Inventory	1,703	1,619	- 5%
Number of **Active Emitting** Pneumatic Controllers Processes	1,703 of 1,703	856 of 1,619	- 49.7%
Total Fuel Usage Per Device [scf] by **Active Emitting** Pneumatic Controllers Processes	200,630,389.36	84,570,528.33	- 57.8%

The amount of emissions generated by the PRE emission units is directly proportional to fuel usage (throughput), and any change in fuel usage would have an effect on the calculated emissions. The approximately 50% decrease in the fuel usage by emitting PRE processes is similar enough to the decrease in PRE emissions (Table 141) that it can be safely concluded that the reduction in throughput is the major cause in the change in emissions between 2017 final and 2021 draft data. Based on these conclusions, no further assessments are conducted on PRE processes.

> ***NOTE:*** The 138 monthly records of erroneous PRE hours of operation in month that were identified earlier in Section 4.6.2.4 and corrected by operators also impacted PRE emissions.

Table 141: Pneumatic controller emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CH_4	15,470	6,329	- 9,141	- 59.1%
CO_2	377	140	- 237	- 62.9%
CO_2-E	387,138	158,372	- 228,766	- 59.1%
VOC	2,222	890	- 1,332	- 59.9%

6.6.5.9 Storage Tank (STO)

The total count of the STO emission units decreased by 11% in the 2021 draft inventory (298 STO processes were reported in the 2021 draft inventory), but only 197 of 298 STO processes were active and emitting (Table 124); the remaining processes belonged to non-operating facilities or were reported as zero emissions processes. Emitting STO processes decreased by 41.36% in the 2021 draft inventory, which resulted in a 60.7% decrease in total throughput to the STO processes (Table 142). This decrease in throughput is consistent with the decrease in emissions (Table 143), and it can be concluded that this is the main cause of the decrease in STO emissions.

Table 142: Storage tank throughputs and equipment counts by inventory year with % change

Parameter	2017 Final	2021 Draft	% Change
Number of Storage Tanks Processes Reported in the Inventory	336	298	- 11.3%
Number of **Active Emitting** Storage Tanks Processes	336 of 336	197 of 298	- 41.4%
Throughput to **Active Emitting** Storage Tanks Processes	1,197,889,584	469,937,282	- 60.7%

Table 143: Storage tank emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Draft	Difference	% Change
CH_4	551	187	- 364	- 66.1%
CO_2-E	13,784	4,677	- 9,107	- 66.1%
VOC	556	189	- 367	- 66.0%

7 Summary of Issues Found and Corrective Actions (Platform Sources)

This section summarizes the notable QA/QC findings where the analysis done in the previous sections identified corrective actions for reporting of emissions from platform sources. Table 144 summarizes the issues identified in the 2021 draft inventory, grouped by equipment type.

Error in hours of operation per month were identified under all equipment types that had hours of operation fields under their data request in OCS AQS (Table 144). Similarly, activity data submitted for equipment types requiring the number of operating days in a month (rather than the hours) also had inaccurate values (values exceeding the maximum number of days in a month). These two commonly observed data entry issues led implementing targeted automated QA checks in OCS AQS for future efforts. These checks will flag entries with out-of-range values (e.g., days in a month and hours in a month) and account for the differences in the number of days per month. Although these issues were identified under all equipment types, the Team requested corrective actions only for the equipment types that directly depend on the number of hours and days of operation per month for emissions calculations (specifically PNE, PRE, AMI, GLY, FUG, and STO) (marked as “X” in Table 144). For other equipment types, the hours, and days of operation per month were not mandatory and does not impact calculated emissions, which will not impact calculated emissions (marked as “O” in Table 144).

Data entry issues found in the fuel sulfur content data strongly influenced the SO_2 emissions from combustion equipment (specifically BOI, DIE, and NGT) and caused a substantial (but misleading) increase in calculated SO_2 emissions. Fuel heating value can also affect combustion equipment emissions; however, issues in fuel heating values were only observed under BOI emissions units.

Detecting issues with cold vents and flares is more complex than combustion equipment because there are multiple inputs used in calculating these emissions. Vents also account for emissions generated by other emissions units that do not vent their emissions locally. The Team was able to identify the issues in the reported concentration of VOCs in the vented gas data under the cold vent emission units. In addition, flare gas heating values for some of the combustion flare emission units were unexpectedly low and required corrective action because they considerably impacted combustion flare emissions.

Except for the issues related to hours and days of operation, data reported under non-combustion equipment did not require corrective action. The Team identified some instances with inconsistent reporting of emissions destination when stream analysis was conducted under GLY, LOS, and STO; however, these issues (marked as “O” in Table 144) did not impact final emissions calculations and did not require corrective action.

Table 145 summarizes the number of emission units with data entry issues by equipment type. In addition, Figure 53 provides a stacked bar chart showing the number of emissions units with data entry issues by equipment type. As illustrated, the majority of the problematic emission units were FUG, followed by NGT. To reiterate, the issues related to stream analysis identified under GLY, LOS, and STO did not require corrective actions. The Team only needed to verify the emissions destination's consistency and ensure they were vented or flared to facilities with a cold vent or flare (Section 4.6.5).

> ***NOTE:*** The counts of the issues in Table 145 are aggregated by emissions unit, meaning that, if an emission unit has an activity data issue for more than 1 month, the reported count is still 1 (the emission unit).

Table 144: Summary of issues found by equipment type in the 2021 draft inventory for platform sources

Equipment Type	Fuel Sulfur Content	Flare Gas Heating Value	Concentration of VOC in the Vented Gas	Fuel Heating Value	Hours of Operation per Month	Number of Operating Days in Month	Stream Analysis
AMI	-	-	-	-	X	-	-
BOI	X	-	-	X	O	-	-
DIE	X	-	-	-	O	-	-
DRI	-	-	-	-	O	-	-
FLA	-	X	-	-	O	-	-
FUG	-	-	-	-	-	X	-
GLY	-	-	-	-	X	-	O
LOA	-	-	-	-	-	-	-
LOS	-	-	-	-	O	-	O
MUD	-	-	-	-	-	-	-
NGE	-	-	-	-	O	-	-
NGT	X	-	-	-	O	-	-
PNE	-	-	-	-	X	-	-
PRE	-	-	-	-	X	-	-
STO	-	-	-	-	-	X	O
VEN	-	-	X	-	O	-	-

NOTES: X = identified issue, corrective action taken

O = identified issue, corrective action **not** taken (does not have direct impact on calculated emissions)

See Table 124 for equipment type abbreviations key.

Table 145: Count of emission unit (number) with issues by equipment type in the 2021 draft inventory

#	Equipment Type	Emission Units in 2021 Draft Inventory	Emission Units with Issues
1	FUG	3,618	192
2	PNE	3,265	6
3	DIE	2,442	8
4	PRE	1,619	30
5	NGE	1,199	5
6	VEN	666	84
7	NGT	437	159
8	BOI	429	12
9	LOS	405	4
10	STO	298	13
11	GLY	187	50
12	FLA	114	5
13	MUD	16	0
14	DRI	15	0
15	AMI	4	3
16	LOA	1	0
-	Total	**14,715**	**571**

See Table 124 for equipment type abbreviations key.

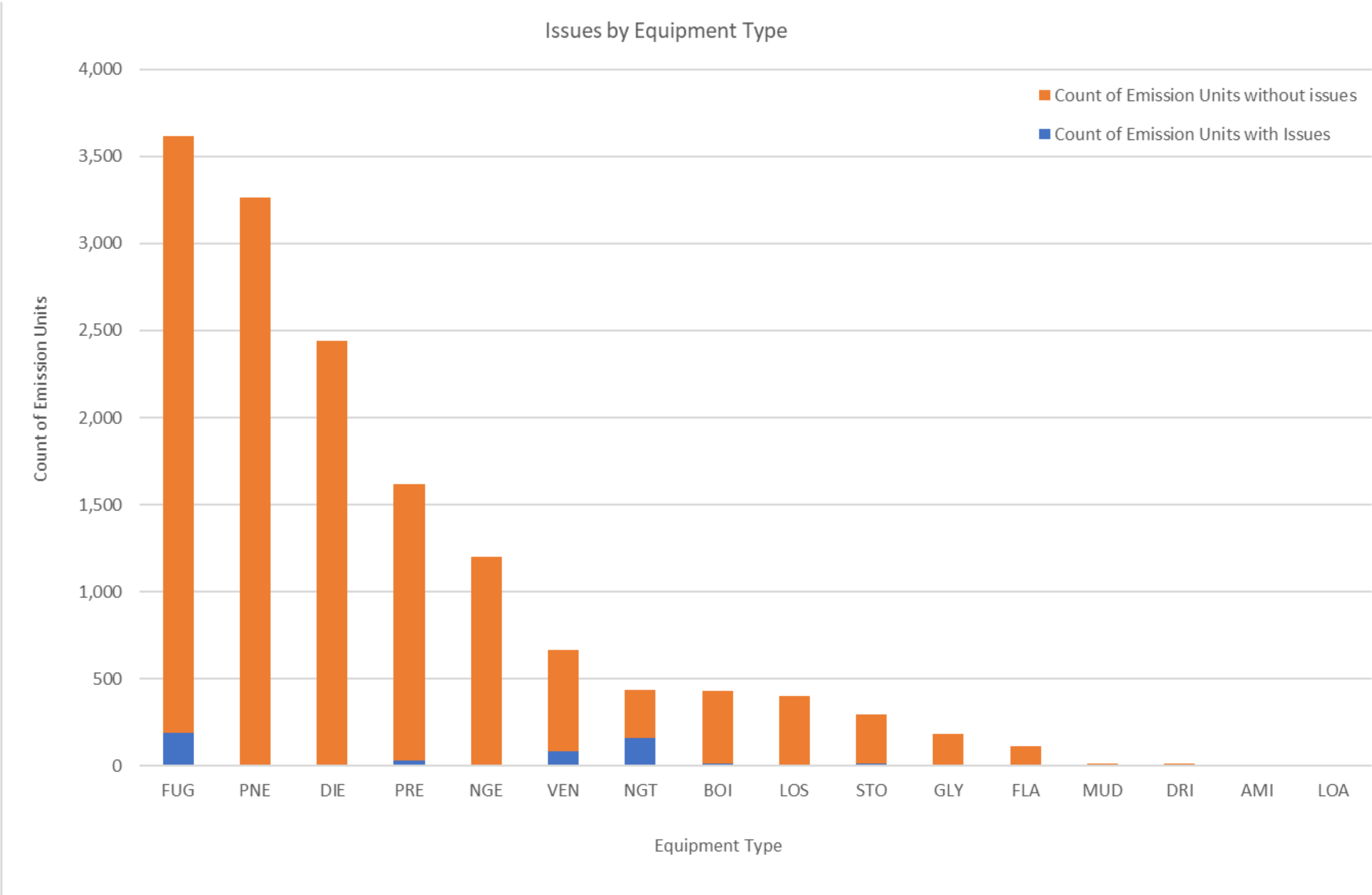


Figure 53: Count of emission units (number) with and without issues by equipment type in the 2021 draft inventory
See Table 124 for equipment type abbreviations key.

8 Incorporating 2021 Draft Inventory Revisions – Platform Emissions

Operators were advised to review and revise the data they initially submitted into OCS AQS, as per the deadline specified in the BOEM NTL No. 2020-N03 (https://www.boem.gov/sites/default/files/documents/about-boem/NTL-2020-N03.pdf) . The requests for revisions were submitted to BOEM, and the operators were given until November 2022 to complete those revisions. Of the 64 companies that submitted their inventories into OCS AQS, 227 facilities belonging to 46 companies were set to corrective action to address activity data issues identified and discussed in previous sections. The Team incorporated the operators' revisions into the main 2021 database in OCS AQS. As a result of this action, two databases are available: 2021 draft inventory data (before corrective actions, July 2022 version) and 2021 final inventory data (after incorporating the corrective actions).

8.1 2021 Draft vs. Final Emissions Inventory

Table 146 compares the 2021 draft and final inventories. This table demonstrates the adjustment of different pollutants emissions after correcting the data entry issues reported by the Team.

Due to the corrective actions that were made to fix the anomaly value of the flare pilot feed rate, the CO_2 and CO_2-E emissions decreased by 62% and 54%, respectively, in the final 2021 inventory (Table 144). Moreover, corrective actions that addressed the high fuel sulfur content in turbines decreased SO_2 emissions by 80% in the final inventory. Similarly, due to the revisions on VOC concentration in vented gas, emissions of hexane, VOC, benzene, ethylbenzene, and xylene decreased by 28%, 22%, 17%, 13%, and 13%, respectively, in the 2021 final inventory. Revisions made to the throughputs of the three boiler emissions units resulted in slight decreases for NH_3, beryllium, chromium (VI), chromium (III), cadmium, and mercury. Likewise, fixing the hours of operation for pneumatic pumps to not to exceed the maximum number of hours in a month also caused a decrease in CH_4 in the 2021 final emissions.

In contrast, acetaldehyde, formaldehyde, and 2,2,4-trimethylpentane included in the 2021 final inventory increased by 17%, 12%, and 10%, respectively, after low flare gas heating values were resolved (Section 6.6.4.1). Fixing the low flare gas heating values on a small scale increased the N_2O, CO, and NO_x emissions in the 2021 final inventory.

> ***NOTE:*** The activity data that prompted the corrective action for each pollutant is summarized in Table 146 under the "Activity Data that Triggered the Corrective Action" column. It should be mentioned that other corrective actions might have also contributed to the emissions changes from the 2021 draft to final inventory.

Table 146: 2021 draft vs. final emissions inventory (in tons/year) by pollutant with % change

#	Pollutant	2021 Draft Inventory	2021 Final Inventory	Difference	Percentage Change[a]	Activity Data that Triggered the Corrective Action	OCS AQS Data Request Field
1	Acetaldehyde	213.211	248.502	+ 35.291	+ 17%	Low Flare Gas Heating Value	Flare Gas Heating Value [Btu/scf]
2	2,2,4-Trimethylpentane	8.517	9.507	+ 0.99	+ 12%	Low Flare Gas Heating Value	Flare Gas Heating Value [Btu/scf]
3	Formaldehyde	542.427	595.353	+ 52.926	+ 10%	Low Flare Gas Heating Value	Flare Gas Heating Value [Btu/scf]
4	Nitrous Oxide (N_2O)	121.196	121.92	+ 0.724	+ 1%	Low Flare Gas Heating Value	Flare Gas Heating Value [Btu/scf]
5	Carbon Monoxide (CO)	28,387.616	28,551.228	+ 163.612	+ 1%	Low Flare Gas Heating Value	Flare Gas Heating Value [Btu/scf]
6	Nitrogen Oxides (NO_X)	34,651.346	34,660.535	+ 0.811	0%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
7	Arsenic	0.0041	0.0041	0	0%	-	-
8	Lead	0.0056	0.0056	0	0%	-	-
9	Methane (CH_4)	95,945.61	95,833.721	- 111.889	- 0.1%	PNE hours	Hours of Operation per Month [hr]
10	Mercury	0.2477	0.2467	- 0.001	- 0.4%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
11	Chromium III	0.4817	0.4797	- 0.002	- 0.4%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
12	Cadmium	0.2613	0.2602	- 0.0011	- 0.4%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
13	Chromium (VI)	0.0206	0.0205	- 1E-04	- 0.5%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
14	Beryllium	0.00012506	0.00012442	- 6.4E-07	- 1%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
15	Toluene	25.249	24.692	- 0.557	- 2%	High VOC Concentration in Vented Gas	Concentration of VOC in the Vented Gas [ppmv]
16	Ammonia (NH_3)	4.614	4.442	-0.172	- 4%	High Fuel Usage in Boilers	Total Fuel Usage [Mscf/month]
17	Xylenes (Mixed Isomers)	17.623	15.395	-2.228	- 13%	High VOC Concentration in Vented Gas	Concentration of VOC in the Vented Gas [ppmv]
18	Ethyl Benzene	4.234	3.693	-0.541	- 13%	High VOC Concentration in Vented Gas	Concentration of VOC in the Vented Gas [ppmv]
19	Benzene	49.893	41.354	-8.539	- 17%	High VOC Concentration in Vented Gas	Concentration of VOC in the Vented Gas [ppmv]
20	Volatile Organic Compounds (VOC)	39,727.642	30,911.005	-8,816.637	- 22%	High VOC Concentration in Vented Gas	Concentration of VOC in the Vented Gas [ppmv]
21	Hexane	617.415	440.942	-176.473	- 29%	High VOC Concentration in Vented Gas	Concentration of VOC in the Vented Gas [ppmv]
22	CO2-E (CO_2E)	18,228,399.31	8,367,509.97	-9,860,889.34	- 54%	High volume of gas flared	Pilot Feed Rate [Mscf/day]
23	Carbon Dioxide (CO_2)	15,793,642.60	5,935,334.81	-9,858,307.79	- 62%	High volume of gas flared	Pilot Feed Rate [Mscf/day]
24	Sulfur Dioxide (SO_2)	1,534.591	299.419	-1,235.172	- 80%	High Fuel Sulfur Content in Turbines	Fuel Sulfur Content [wt%]

Notes: [a] $Percentage\ Change = \frac{\text{2021 Final Emissions} - \text{2021 Draft Emissions}}{\text{2021 Draft Emissions}} \times 100\%$

8.2 2017 vs. 2021 Final Emissions Inventory

Table 147 shows data exported from the inventory analysis tab in the Data Analytics Dashboard in OCS AQS. The Data Analytics Dashboard was implemented to support and automate QA/QC of submitted data. The dashboard provides an overview of the calculated emissions in the previous and current inventories (in this case, 2017 final and 2021 final).

In summary, the amount of most emitted pollutants decreased in 2021 in comparison to 2017. For example, CO_2 and CH_4 emissions decreased moderately, resulting in an overall reduction in the CO_2-E emissions despite a minimal increase in N_2O emissions. Except for acetaldehyde, VOC and HAP emissions also decreased in the 2021 revised inventory. Likewise, criteria emissions decrease ranged between 20 and 50% in the 2021 inventory. Those discrepancies in the amounts of annual emissions are directly related to the decrease in the count of operational emitting platforms in the 2021 inventory (Section 4.5). The reduced count of operating platforms also resulted in a decrease in the fuel usage and throughput. The following section presents a summary of the total 2021 final inventory platform emissions, grouped by equipment type, to show the annual pollutant contributions (in tons).

Table 147: Platform emissions (tons/year) by inventory year with % change

#	Pollutant	2017 Final	2021 Final	Difference	%Change
1	Acetaldehyde	155.005	248.502	+ 93.497	+ 60.32 %
2	Arsenic	0.003	0.004	+ 0.002	+ 57.42 %
3	Lead	0.004	0.006	+ 0.002	+ 46.67 %
4	Beryllium	8.6565E-05	1.2442E-04	+ 3.7852E-005	+ 43.73 %
5	Chromium (VI)	0.019	0.021	+ 0.002	+ 8.01 %
6	Chromium III	0.448	0.480	+ 0.032	+ 7.10 %
7	Mercury	0.231	0.247	+ 0.016	+ 6.84 %
8	Cadmium	0.244	0.260	+ 0.016	+ 6.62 %
9	Nitrous Oxide	118.210	121.920	+ 3.710	+ 3.13 %
10	2,2,4-Trimethylpentane	9.619	9.507	- 0.112	- 1.16 %
11	Carbon Dioxide (CO_2)	6,857,359.616	5,935,334.814	- 922,024.8	- 13.45 %
12	Formaldehyde	705.165	595.353	- 109.813	- 15.57 %
13	Volatile Organic Compounds (VOC)	38,832.769	30,911.005	- 7,921	- 20.40 %
14	CO_2-E (CO_2E)	11,589,943.12	8,367,509.973	- 3,222,433	- 27.80 %
15	Nitrogen Oxides (NO_X)	49,962.027	34,660.535	- 15,301.5	- 30.63 %
16	Sulfur Dioxide (SO_2)	462.055	299.419	- 162.6	- 35.20 %
17	Hexane	765.512	440.942	- 324.5	- 42.40 %
18	Carbon Monoxide (CO)	51,872.132	28,551.228	- 23,320.9	- 44.96 %
19	Ammonia (NH_3)	8.394	4.442	- 3.952	- 47.08 %
20	Methane (CH_4)	187,894.280	95,833.721	- 92,060.56	- 48.00 %
21	Ethyl Benzene	17.910	3.693	- 14.217	- 79.38 %
22	Benzene	225.433	41.354	- 184.079	- 81.66 %
23	Xylenes (Mixed Isomers)	101.580	15.395	- 86.185	- 84.84 %
24	Toluene	226.231	24.692	- 201.539	- 89.09 %

8.3 2021 Final Emissions by Equipment Type

8.3.1 2021 Final GHG Emissions by Equipment Type

Table 148 presents the platform calculated emissions for GHG pollutants, with the highest values for each pollutant, by equipment type, in bold. Appendix B displays geographical distribution of GHG emissions for the region.

Combustion equipment (specifically turbines and NGE) and combustion flares are the highest contributors of CO_2 emissions. Those high contributions are expected since the combustion process converts hydrocarbons into energy and generates high rates of CO_2 gases as a by-product.

N_2O emissions are only emitted from flares, turbines, and boilers. The emitted amount of N_2O is relatively low compared to CO_2, but their overall impact is high since the GWP factor used to calculate CO_2-E for N_2O emissions in the 2021 draft data was 298.

Although venting excess hydrocarbons directly into the atmosphere without further processing is expected to reduce CO_2 emissions, venting also releases higher rates of CH_4 (see CH_4 emissions from fugitives and cold vents in Table 148). The GWP used to calculate CO_2-E for CH_4 in the 2021 draft data was 25. Table 148 shows that, for example, the calculated CO_2-E emissions from cold vents and NGE are comparable, but CO_2 emissions from cold vents are drastically lower than CO_2 from NGE. CO_2-E emissions for cold vents are augmented by the CH_4 contributions.

Looking broadly at CO_2-E emissions, natural gas, diesel, or dual fuel turbines are the highest CO_2-E emitter, followed by NGE and cold vents.

Table 148: 2021 final total annual platform GHG emissions (tons/year) by equipment type

Equipment Type	CO_2 (GWP = 1)	CH_4 (GWP = 25)	N_2O (GWP = 298)	CO_2-E
Amine Unit	0	0	-	0
Boiler/Heater/Burner	153,160	2.92	2.76	154,056
Cold Vent	1,038	***40,077**	0	1,002,969
Combustion Flare	462,900	2,297	7.89	522,674
Drilling Equipment	22,661	1.11	-	22,688
Engine – Diesel or Gasoline Engine	225,831	5.26	-	225,962
Engine – Natural Gas	935,394	4,436	-	1,046,301
Fugitives	-	28,273	-	706,820
Glycol Dehydrator	-	325	-	8,130
Losses from Flashing	28.6	1,231	-	30,807
Mud Degassing	1.22	131	-	3,283
Pneumatic Controller	139	6,346	-	158,800
Pneumatic Pump	265	12,139	-	303,730
Storage Tank	-	250	-	6,238
Turbine – Natural Gas, Diesel, or Dual Fuel	***4,133,918**	319	***111**	***4,175,051**
Total	5,935,335.82	95,833.29	121.65	8,367,509

Notes: * = highest emission source per pollutant (also in bold)

8.3.2 2021 Final Criteria Pollutants and Precursors Emissions by Equipment Type

Table 149 presents the draft criteria and precursor pollutant emissions from the 16 different equipment types of platform sources. Appendix B displays geographical distribution of criteria pollutant emissions for the region.

The main takeaways from Table 149 are as follows:

- CO is emitted at higher rates from the combustion equipment and combustion flares (possibly due to incomplete combustion process).
- NO_x is emitted by the NGE in substantial amounts, followed by turbine – natural gas, diesel, or dual fuel turbines.
- VOC emissions from cold vents are substantially higher than all other equipment type.

Table 149: 2021 final total annual criteria pollutants and precursor platform emissions (tons/year) by equipment type

Equipment Type	NH_3	CO	Pb	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Amine Unit	-	-	-	-	-	-	-	-
Boiler/Heater/Burner	***4.09**	107	6.92E-04	240	2.46	2.42	0.771	6.98
Cold Vent	-	-	-	-	-	-	-	***12,570**
Combustion Flare	0.348	1,194	5.43E-05	271	6.2	6.2	23.7	7,518
Drilling Equipment	-	117	-	439	7.87	7.69	0.208	11.2
Engine – Diesel or Gasoline Engine	-	1,239	-	5,259	***260**	***253**	***241**	311
Engine – Natural Gas	-	***22,862**	-	***16,323**	74.4	74.4	5	463
Fugitives	-	-	-	-	-	-	-	7,162
Loading Operation	-	-	-	-	-	-	-	0
Losses from Flashing	-	-	-	-	-	-	-	55.4
Pneumatic Controller	-	-	-	-	-	-	-	892
Pneumatic Pump	-	-	-	-	-	-	-	1,592
Storage Tank	-	-	-	-	-	-	-	252
Turbine – Natural Gas, Diesel, or Dual Fuel		3,032	0.00481	12,128	72	72	29.1	78
Total	4.44	28,551	0.01	34,660	422.9	415.7	299.78	30,911.6

Notes: * = highest emission source per pollutant (also in bold)

NOTE: In Table 148 and Table 149, "0" indicates that a value of 0 was calculated based on provided activity data, or that the process was zeroed out. A "-" indicates that the equipment type does not emit this pollutant.

NOTE: PM_{10} and $PM_{2.5}$ emissions in OCS AQS can be for filterable or primary depending on the equipment type.

9 Lease Operations QA/QC (Non- platform Sources)

This year is the initial year that operators were requested under BOEM NTL No. 2020-N03 to report lease operations (in the past, these inputs were labeled as "non-platform sources"). Lease operations include activities of drilling rigs (for example, mobile offshore drilling units), installation support vessels, and well stimulation vessels.

This section describes two separate QA/QC investigations on the lease operations data. Section 9.1 reviews the quality and accuracy of the lease operations data submitted in the 2021 draft inventory. Section 9.2 reviews the completeness of submitted lease operations by comparing them against the BOEM eWell database to report the non-submitted or missing drilling rigs activities from the 2021 inventory.

9.1 Lease Operations Emissions Trends

This section presents a review of the quality and accuracy of the lease operations data submitted during the 2021 reporting cycle.

> ***NOTE:*** The reviewed 2021 lease operations activity data and emissions serve as a baseline for further comprehensive comparisons in future reporting cycles.

9.1.1 Hours of Operation Per Period

When reporting a lease source activity to calculate emissions, operators are required to provide the dates on which the source moved on and off. OCS AQS calculates emissions based on the provided activity data, such as hours of operation per period. During the analysis of activity data, the Team observed that, in some instances, provided hours of operation per period exceeded the maximum number of hours between the moved on and moved off dates.

Consequently, the Team contacted the companies reporting those inconsistent hours of operation and requested corrective actions. Table 150 lists information regarding the sources that required corrective actions. After those operators fixed the inconsistent values, the Team verified the accuracy of the corrected values and approved the resubmitted values.

Table 150: Lease sources that require corrective action based on move on and move off dates in the 2021 draft data

Company Name	Lease	Lease Source	Process	Date Moved On	Date Moved Off	Hours of Operation per Period
Anadarko Petroleum Corporation	G35315	DRI-Crude	DIE-M03R-DO	12-May-2021	06-Jun-2021	672
Arena Offshore, LP	G00981	DRI-Crude	DIE-M03R-DO	14-Oct-2021	15-Nov-2021	816
Arena Offshore, LP	OCS-G-06093	DRI-Crude	DIE-M03R-DO	25-Nov-2021	31-Dec-2021	912
Arena Offshore, LP	OCS-G-06093	DRI-Crude	DIE-M03R-DO	31-Oct-2021	24-Nov-2021	768

9.1.2 Fuel Sulfur Content

The data request for the lease emission sources that operate with diesel engines where max HP => 600 have a fuel sulfur content parameter field. This field is required to calculate the SO_2 emissions from those sources, based on the amount of sulfur in the fuel used. The Team reviewed all provided fuel sulfur content values under all leases to investigate high values and request corrective actions if needed. As a result of this analysis, 98 sources belonging to BP Exploration & Production Inc. were found to have 1% sulfur content. This value is considered high and was suspected to be a data entry error or related to the confusion of using different units (Section 6.5.5.2). Table 151 provides details for the 98 sources under BP Exploration & Production Inc requiring corrective actions for their sulfur content values. After the requested corrective actions, all resubmitted sources now have 0.0015 wt% value instead of 1%. This value is considered adequate, and no further corrective action is required.

In addition, anomalous fuel sulfur content values were noted for 50 sources belonging to Shell Offshore Inc. Those 50 sources reported a value of 0.1% sulfur content. The Team contacted the operator and requested further information regarding those values to confirm their accuracy. The operator verified the accuracy of the submitted values and confirmed that those tankers run on high sulfur diesel fuel.

Table 151: BP Exploration & Production Inc lease sources that required fuel sulfur content corrective actions in the 2021 draft data

#	Lease	Lease Source	Process	Date Moved On in 2021	Date Moved Off in 2021	Pre-Corrective Action Fuel Sulfur Content [wt%]	Post-Corrective Action Fuel Sulfur Content [wt%]
1	G09868	CSV-PC	DIE-M03R-LO	01-Dec	13-Dec	1	0.0015
2	OCSG-G-14658	CSV-PC	DIE-M03R-LO	01-Jan	16-Jan	1	0.0015
3	OCSG-G-14658	CSV-PC-2	DIE-M03R-LO	28-Mar	13-Apr	1	0.0015
4	OCSG-G-14658	CSV-PC-3	DIE-M03R-LO	22-Apr	27-Apr	1	0.0015
5	OCSG-G-14658	CSV-PC-4	DIE-M03R-LO	23-Jan	30-Jan	1	0.0015
6	OCSG-G-14658	CSV-PC-5	DIE-M03R-LO	04-Feb	16-Feb	1	0.0015
7	OCSG-G-14658	CSV-PC-6	DIE-M03R-LO	04-Mar	11-Mar	1	0.0015
8	OCSG-G-14658	CSV-PC-7	DIE-M03R-LO	06-Aug	21-Aug	1	0.0015
9	OCSG-G-14658	CSV-PC-8	DIE-M03R-LO	06-Jan	26-Jan	1	0.0015
10	OCSG-G-14658	CSV-PC-9	DIE-M03R-LO	08-Feb	28-Feb	1	0.0015
11	OCSG-G-14658	CSV-PC-10	DIE-M03R-LO	01-Mar	06-Mar	1	0.0015
12	OCSG-G-14658	CSV-PC-11	DIE-M03R-LO	01-Jan	10-Jan	1	0.0015
13	OCSG-G-14658	CSV-PC-12	DIE-M03R-LO	16-Jul	20-Jul	1	0.0015
14	OCSG-G-14658	CSV-PC-13	DIE-M03R-LO	17-Jan	20-Jan	1	0.0015
15	OCSG-G-14658	CSV-PC-14	DIE-M03R-LO	28-Apr	30-Apr	1	0.0015
16	OCSG-G-15607	CSV-PC	DIE-M03R-LO	24-May	31-May	1	0.0015
17	OCSG-G-15607	CSV-PC-2	DIE-M03R-LO	01-Jan	06-Jan	1	0.0015
18	OCSG-G-15607	CSV-PC-3	DIE-M03R-LO	21-Feb	28-Feb	1	0.0015
19	OCSG-G-15607	CSV-PC-4	DIE-M03R-LO	01-Mar	03-Mar	1	0.0015
20	OCSG-G-15607	CSV-PC-5	DIE-M03R-LO	17-Sep	22-Sep	1	0.0015
21	G15610	CSV-PC	DIE-M03R-LO	05-May	09-May	1	0.0015
22	G15610	CSV-PC-2	DIE-M03R-LO	25-Jun	27-Jun	1	0.0015
23	G15610	CSV-PC-3	DIE-M03R-LO	23-Sep	27-Sep	1	0.0015
24	G30300	CSV-PC	DIE-M03R-LO	12-Aug	27-Aug	1	0.0015
25	G30300	CSV-PC-2	DIE-M03R-LO	01-Sep	10-Sep	1	0.0015
26	G30300	CSV-PC-3	DIE-M03R-LO	28-Oct	19-Nov	1	0.0015

#	Lease	Lease Source	Process	Date Moved On in 2021	Date Moved Off in 2021	Pre-Corrective Action Fuel Sulfur Content [wt%]	Post-Corrective Action Fuel Sulfur Content [wt%]
27	G30300	CSV-PC-4	DIE-M03R-LO	21-Sep	24-Nov	1	0.0015
28	G30300	CSV-PC-5	DIE-M03R-LO	30-Nov	27-Dec	1	0.0015
29	G30300	CSV-PC-6	DIE-M03R-LO	01-Dec	31-Dec	1	0.0015
30	G30300	CSV-PC-7	DIE-M03R-LO	08-Jan	14-Jan	1	0.0015
31	G30300	CSV-PC-8	DIE-M03R-LO	20-Oct	09-Nov	1	0.0015
32	OCSG-G-19966	CSV-PC	DIE-M03R-LO	07-Jan	08-Jan	1	0.0015
33	OCSG-G-19966	CSV-PC-2	DIE-M03R-LO	20-Jun	21-Jun	1	0.0015
34	OCSG-G-19966	CSV-PC-3	DIE-M03R-LO	27-Oct	27-Oct	1	0.0015
35	OCSG-G-19966	CSV-PC-4	DIE-M03R-LO	28-Oct	30-Oct	1	0.0015
36	OCSG-G-19966	CSV-PC-5	DIE-M03R-LO	21-Nov	22-Nov	1	0.0015
37	OCSG-G-19966	CSV-PC-6	DIE-M03R-LO	18-Nov	30-Nov	1	0.0015
38	OCSG-G-19966	CSV-PC-7	DIE-M03R-LO	01-Dec	03-Dec	1	0.0015
39	OCSG-G-19966	CSV-PC-8	DIE-M03R-LO	07-Nov	21-Nov	1	0.0015
40	OCSG-G-09821	CSV-PC	DIE-M03R-LO	07-Jan	13-Jan	1	0.0015
41	OCSG-G-09821	CSV-PC-2	DIE-M03R-LO	01-Feb	18-Feb	1	0.0015
42	OCSG-G-09821	CSV-PC-3	DIE-M03R-LO	04-Mar	19-Mar	1	0.0015
43	OCSG-G-09821	CSV-PC-4	DIE-M03R-LO	26-Mar	31-Mar	1	0.0015
44	OCSG-G-09821	CSV-PC-5	DIE-M03R-LO	14-Apr	13-May	1	0.0015
45	OCSG-G-09821	CSV-PC-6	DIE-M03R-LO	24-Jun	29-Jun	1	0.0015
46	OCSG-G-09821	CSV-PC-7	DIE-M03R-LO	01-Apr	09-Apr	1	0.0015
47	OCSG-G-09821	CSV-PC-8	DIE-M03R-LO	01-May	13-May	1	0.0015
48	OCSG-G-09821	CSV-PC-9	DIE-M03R-LO	14-Jun	24-Jun	1	0.0015
49	OCSG-G-09821	CSV-PC-10	DIE-M03R-LO	19-May	23-May	1	0.0015
50	OCSG-G-09821	CSV-PC-11	DIE-M03R-LO	01-Jun	09-Jun	1	0.0015
51	OCSG-G-09821	CSV-PC-12	DIE-M03R-LO	24-May	28-May	1	0.0015
52	OCSG-G-09821	CSV-PC-13	DIE-M03R-LO	02-Jun	14-Jun	1	0.0015
53	OCSG-G-09821	CSV-PC-14	DIE-M03R-LO	18-Oct	24-Oct	1	0.0015
54	OCSG-G-09821	CSV-PC-15	DIE-M03R-LO	21-Oct	22-Oct	1	0.0015
55	OCSG-G-09821	CSV-PC-16	DIE-M03R-LO	07-Dec	16-Dec	1	0.0015
56	OCSG-G-09821	CSV-PC-17	DIE-M03R-LO	09-Dec	10-Dec	1	0.0015
57	OCSG-G-09821	CSV-PC-18	DIE-M03R-LO	19-Oct	29-Oct	1	0.0015
58	OCSG-G-09821	CSV-PC-19	DIE-M03R-LO	01-Dec	15-Dec	1	0.0015
59	OSCG-G-09981	CSV-PC	DIE-M03R-LO	12-Nov	13-Nov	1	0.0015
60	OSCG-G-09981	CSV-PC-2	DIE-M03R-LO	01-Jan	28-Feb	1	0.0015
61	OCSG-G-15604	CSV-PC	DIE-M03R-LO	21-May	23-May	1	0.0015
62	OCSG-G-15604	CSV-PC-2	DIE-M03R-LO	11-Nov	11-Nov	1	0.0015
63	OCSG-G-15604	CSV-PC-3	DIE-M03R-LO	04-Dec	04-Dec	1	0.0015
64	OCSG-G-15604	CSV-PC-4	DIE-M03R-LO	28-Sep	29-Sep	1	0.0015
65	OCSG-G-09867	CSV-PC	DIE-M03R-LO	03-Jun	03-Jun	1	0.0015

#	Lease	Lease Source	Process	Date Moved On in 2021	Date Moved Off in 2021	Pre-Corrective Action Fuel Sulfur Content [wt%]	Post-Corrective Action Fuel Sulfur Content [wt%]
66	OCSG-G-09867	CSV-PC-2	DIE-M03R-LO	15-Jun	15-Jun	1	0.0015
67	OCSG-G-09867	CSV-PC-3	DIE-M03R-LO	24-Jun	24-Jun	1	0.0015
68	OCSG-G-09867	CSV-PC-4	DIE-M03R-LO	17-Jul	18-Jul	1	0.0015
69	OCSG-G-09867	CSV-PC-5	DIE-M03R-LO	27-Jul	31-Jul	1	0.0015
70	OCSG-G-09866	CSV-PC	DIE-M03R-LO	31-Oct	10-Nov	1	0.0015
71	OCSG-G-09866	CSV-PC-2	DIE-M03R-LO	01-Aug	03-Aug	1	0.0015
72	OCSG-G-09866	CSV-PC-3	DIE-M03R-LO	25-Oct	25-Oct	1	0.0015
73	OCSG-G-23624	CSV-PC	DIE-M03R-LO	10-Jun	09-Jul	1	0.0015
74	OCSG-G-23624	CSV-PC-2	DIE-M03R-LO	09-Jul	26-Jul	1	0.0015
75	OCSG-G-23624	CSV-PC-3	DIE-M03R-LO	01-Aug	27-Aug	1	0.0015
76	OCSG-G-23624	CSV-PC-4	DIE-M03R-LO	04-Sep	07-Sep	1	0.0015
77	OCSG-G-23624	CSV-PC-5	DIE-M03R-LO	30-Sep	30-Sep	1	0.0015
78	OCSG-G-23624	CSV-PC-6	DIE-M03R-LO	06-Aug	23-Aug	1	0.0015
79	OCSG-G-23624	CSV-PC-7	DIE-M03R-LO	19-Dec	20-Dec	1	0.0015
80	OCSG-G-08823	CSV-PC	DIE-M03R-LO	01-Oct	02-Oct	1	0.0015
81	OCSG-G-35823	CSV-PC	DIE-M03R-LO	04-Nov	06-Nov	1	0.0015
82	OCSG-G-35823	CSV-PC-2	DIE-M03R-LO	12-Dec	14-Dec	1	0.0015
83	OCSG-G-09962	CSV-PC	DIE-M03R-LO	13-Mar	05-Apr	1	0.0015
84	OCSG-G-33855	CSV-PC	DIE-M03R-LO	01-Jan	25-Jan	1	0.0015
85	OCSG-G-33855	CSV-PC-2	DIE-M03R-LO	11-Jul	18-Jul	1	0.0015
86	OCSG-G-23579	CSV-PC	DIE-M03R-LO	27-Jun	27-Jun	1	0.0015
87	OCSG-G-28101	CSV-PC	DIE-M03R-LO	01-May	07-May	1	0.0015
88	OCSG-G-15609	CSV-PC	DIE-M03R-LO	01-May	18-May	1	0.0015
89	OCSG-G-15609	CSV-PC-2	DIE-M03R-LO	05-Jul	15-Jul	1	0.0015
90	OCSG-G-14658	CSV-WS	DIE-M03R-LO	27-Nov	30-Dec	1	0.0015
91	OCSG-G-15607	CSV-WS	DIE-M03R-LO	08-Jan	10-Feb	1	0.0015
92	OCSG-G-15607	CSV-WS-2	DIE-M03R-LO	20-Feb	04-Mar	1	0.0015
93	OCSG-G-15607	CSV-WS-3	DIE-M03R-LO	12-Mar	12-Apr	1	0.0015
94	OCSG-G-19966	CSV-WS	DIE-M03R-LO	04-May	04-Jun	1	0.0015
95	OCSG-G-07944	CSV-WS	DIE-M03R-LO	05-Jul	17-Jul	1	0.0015
96	OCSG-G-09867	CSV-WS	DIE-M03R-LO	01-Jan	09-Jan	1	0.0015
97	OCSG-G-09866	CSV-WS	DIE-M03R-LO	10-Jan	31-Jan	1	0.0015
98	OCSG-G-08823	CSV-WS	DIE-M03R-LO	18-Jul	25-Jul	1	0.0015

9.1.3 Total Vessel Power

Lease emission sources that depend on vessel power to calculate emissions have a total vessel power data request field in OCS AQS. Determining an acceptable value of a total vessel power is not straightforward because the consumed power depends, in large part, on the operations that a vessel is performing. Moreover, the absence of the 2017 final data makes it difficult to locate or track data anomalies in the 2021 submitted total vessel power data.

The Team attempted to compare all 2021 draft vessel power rating data using a box-and-whisker plot to identify anomalous values and investigate whether they are valid or resulted from inaccurate data entry (Figure 54). Vessel power data ranged between 0 and 48,666 kW, with a median of 24,360.9 kW and only one outlying value of 87,518 kW. Further investigation of this value revealed that three sources under BP Exploration & Production Inc. had an unexpectedly high vessel power value (Table 152). When contacted, the operators confirmed the entry was mistyped and corrected it to 51,700 kW. Figure 55 shows the post-corrective action box-and-whisker plot. The correction adjusted the median value, and all provided values are now considered acceptable.

Table 152: BP Exploration & Production Inc lease sources requiring vessel power corrective actions in the 2021 draft data

Lease	Lease Source	Process	Date Moved On	Date Moved Off	Pre-Corrective Action Total Vessel Power [kW]	Post-Corrective Action Total Vessel Power [kW]
OCSG-G-15607	DRI-SP-4N	C1C2-DRILL-LO-F	01-Jan-2021	17-Mar-2021	87,518	51,700
OCSG-G-09982	DRI-SP-4-2	C1C2-DRILL-LO-F	11-Apr-2021	26-May-2021	87,518	51,700
OCSG-G-15608	DRI-SP-4N	C1C2-DRILL-LO-F	18-Mar-2021	10-Apr-2021	87,518	51,700

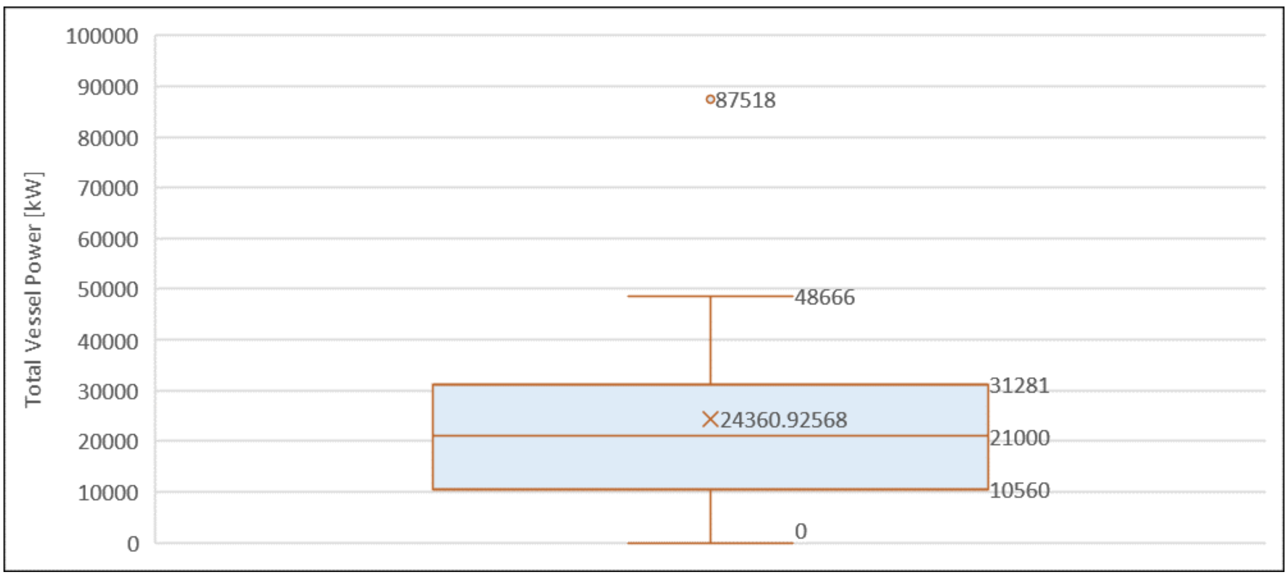


Figure 54: Pre-corrective action total vessel power in the lease operations 2021 draft inventory

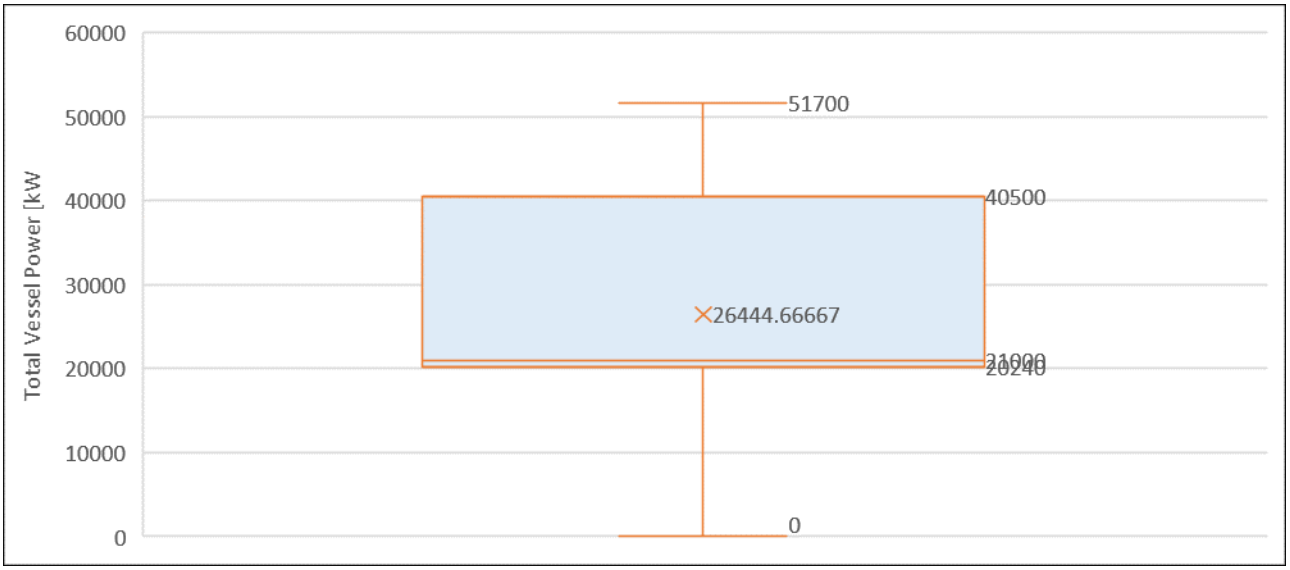


Figure 55: Post-corrective action total vessel power in the lease operations 2021 final inventory

9.2 QA/QC on Completeness of Lease Operations Data – OCS AQS vs. BSEE eWell

The 2021 emissions inventory effort was the first reporting cycle that directly required reporting of non-platform lease operations—which still met the definition of a facility—including drilling operating while connected to the seabed. The objective of this analysis was to account for all reportable lease operation emissions by comparing permitted drilling operation activities registered in the BSEE eWell database with the emissions data reported by operators in OCS AQS to identify discrepancies, errors, or omissions. The BSEE eWell database serves as the permitted record for all drilling activities in the GOM, and the Team queried the database to extract all drilling rig activity, including Drilling (D) or Exploration (E) activities, for the 2021 effort. The extracted eWell data was then compared with operator reported drilling rig emissions from OCS AQS.

The data comparison revealed three types of discrepancies:

- Drilling rig emissions were reported in OCS AQS, but no corresponding permitted activities were found in eWell.
- Permitted drilling activity was reported in eWell, but no corresponding records were reported in OCS AQS.
- Drilling rig activity records were found in both eWell and OCS AQS, but there were discrepancies between move on and move off dates.

To resolve the observed discrepancies, the Team prepared reconciliation reports and emailed operators with instructions to review and comment on each activity.

The comments in the reconciliation report either affirmed that the activity was reported in OCS AQS or, if it was not included, the comment indicated why the activity was not subject to reporting under the NTL and, therefore, not required to be reported in OCS AQS for the 2021 effort.

Table 153 provides a summary of this information and identifies the number of reports delivered and whether corrective action was completed.

Table 153: Summary of corrective action status and reports delivered per operating companies in the lease operations 2021 draft data

#	Company Name	Company Number	Reports Delivered	Corrective Action	Comment
1	Anadarko Petroleum Corporation	00981	19	Yes	Operator corrected submittal
2	ANKOR Energy LLC	03059	8	No	-
3	Arena Offshore, LP	02628	33	No	-
4	Beacon Growthco Operating Company, L.L.C.	03567	1	Yes	Operator corrected submittal
5	BOE Exploration & Production LLC	03572	2	No	-
6	BP Exploration & Production Inc.	02481	16	Yes	Operator corrected submittal
7	Byron Energy Inc.	02961	2	No	-
8	Cantium, LLC	03481	14	Yes	Operator corrected submittal
9	Chevron U.S.A. Inc.	00078	10	No	-
10	Contango Operators, Inc.	02503	1	No	-
11	Cox Operating, L.L.C.	03151	22	No	-
12	Energy XXI GOM, LLC	02375	1	No	-
13	Eni US Operating Co. Inc.	02782	6	No	-
14	EnVen Energy Ventures, LLC	03026	6	No	-
15	EPL Oil & Gas, LLC	02266	1	No	-
16	Equinor Gulf of Mexico LLC	02748	1	No	-
17	GOM Shelf LLC	02451	9	No	-
18	Helis Oil & Gas Company, L.L.C.	01978	2	No	-
19	Hess Corporation	00059	4	No	-
20	Kosmos Energy Gulf of Mexico Operations, LLC	03362	3	No	-
21	LLOG Exploration Offshore, L.L.C.	02058	2	No	-
22	MC Offshore Petroleum, LLC	02957	1	No	-
23	Murphy Exploration & Production Company - USA	02647	7	Yes	Operator corrected submittal
24	Peregrine Oil & Gas II, LLC	02967	1	No	-
25	Renaissance Offshore, LLC	03209	6	No	-
26	Ridgelake Energy, Inc.	02066	1	No	-
27	Sanare Energy Partners, LLC	03520	3	No	-
28	Shell Gulf of Mexico Inc.	02117	2	Yes	Operator did not correct submittal
29	Shell Offshore Inc.	00689	28	Yes	Operator did not correct submittal
30	Talos Energy Offshore LLC	03247	8	No	-
31	Talos ERT LLC	02899	10	No	-
32	Talos Oil and Gas LLC	03269	1	No	-
33	Talos Petroleum LLC	01834	7	No	-
34	Talos Third Coast LLC	03619	5	No	-
35	W & T Energy VI, LLC	03148	1	No	-
36	W & T Offshore, Inc.	01284	14	No	-
37	Walter Oil & Gas Corporation	00730	11	Yes	Operator corrected submittal

Based on feedback from the operators, responses can be categorized as follows:

- Operators provided justification as to why drilling activities recorded in eWell did not meet the definition of a facility and therefore are not required to be reported in OCS AQS. In Table 153, this is represented by a "No" under the Corrective Action column. A list of these justifications is summarized below.
- Operators determined that there were errors or omissions and requested access to their submitted OCS AQS inventory to make the necessary edits or addition. In Table 153, this is represented by a "Yes" under the Corrective Action column. Shell Gulf of Mexico Inc. and Shell Offshore Inc. both had corrective actions that **were not** resolved.

The justifications provided by the operators that did not result in a corrective action included the following:

- Temporarily abandoned or primarily abandoned: no drilling or drill rig connected to the seabed, nor a construction/installation of facilities/pipelines occurred (not subject to reporting).
- No drilling or drill rig connected to the seabed, nor a construction/installation of facilities/pipelines occurred (not subject to reporting).
- Vessels were not attached to the seabed during this period; moved off lease due to loop currents.
- No drilling or drill rig connected to the seabed, nor a construction/installation of facilities/pipelines occurred (not subject to reporting).
- Activities such as wireline and/or coil tubing were performed onboard the platform.
- The activity was already reported, and the eWell dates for "RIGMOVEON" and "RIGMOVEOFF" are not indicative of when a source connects to the seafloor and will not always align with "moved on" and "moved off" dates. The "moved on" and "moved off" dates were based on when the rig connected to (e.g., latched) and disconnected from (e.g., unlatched) the well or other subsea equipment at the seafloor.

Table 154 lists the companies that did not reach out to the Team to set up OCS AQS accounts for missing leases. The operator's name and the associated number of reports were extracted and processed from the BSEE eWell database. The number of reports represents the number of leases that belong to that operator.

Table 154: Companies with missing leases that did not contact the Team for the 2021 effort

#	Company Name	Company Number	No. of Reports
1	Apache Corporation	00105	1
2	Beacon West Energy Group, LLC	03539	2
3	DCOR, L.L.C.	02531	3
4	Deepwater Abandonment Alternatives, Inc.	03521	1
5	EC Offshore Properties, Inc.	03147	1
6	FREEPORT MCMORAN ENERGY LLC	02313	1
7	FREEPORT MCMORAN OIL & GAS LLC	03280	3
8	Hoactzin Partners, L.P.	02801	3
9	Marubeni Oil & Gas (USA) LLC	02806	1
10	McMoRan Oil & Gas LLC	02312	5
11	Northstar Interests, L.C.	01945	1
12	PetroQuest Energy, L.L.C.	02222	1
13	QuarterNorth Energy LLC	03672	5

#	Company Name	Company Number	No. of Reports
14	Sojitz Energy Venture, Inc.	02655	1
15	Tengasco, Inc.	03008	1
16	Texaco Exploration and Production Inc.	00771	1
17	Union Oil Company of California	00003	3

Table 155 summarizes the operating companies that were contacted by the Team but did not reply.

Table 155: Non-responsive operators with accounts in OCS AQS

#	Company Name	Company Number	No. of Reports
1	BHP BILLITON PETROLEUM	02010	3
2	Rooster Petroleum, LLC	02871	1
3	BANDON OIL AND GAS LP	02894	1
4	FIELDWOOD ENERGY LLC	03295	40
5	FIELDWOOD ENERGY OFFSHORE LLC	03035	19
6	High Point Gas Gathering, L.L.C.	03255	1

After analyzing and integrating all the responses from the operators, Table 156 summarizes the number of leases and lease sources before and after corrective actions, and Table 157 summarizes emissions.

Table 156: Lease operations summary (pre- and post-corrective action) with % change

#	Category	Pre-Corrective Action	Post-Corrective Action	% Change
1	Lease	143	174	+ 21.7 %
2	Lease Source	395	456	+ 15.4 %

Table 157: Pre- and post-corrective action lease operations emissions (tons/year) with % change

#	Pollutant	Pre- Corrective Action (tons/year)	Post- Corrective Action (tons/year)	% Change
1	Acetaldehyde	0.0179	0.0336	+ 87.71 %
2	Formaldehyde	0.056	0.1007	+ 79.82 %
3	Xylenes (Mixed Isomers)	0.1369	0.2366	+ 72.83 %
4	Toluene	0.1993	0.3444	+ 72.81 %
5	Benzene	0.5503	0.9504	+ 72.71 %
6	PAH, total	0.1503	0.2593	+ 72.52 %
7	CH_4	13.945	17.132	+ 22.85 %
8	VOC	272.668	287.003	+ 5.26 %
9	CO	5,173.166	5,109.682	- 1.23 %
10	NOx	21,538.596	20,906.905	- 2.93 %
11	CO_2	1,457,379.439	1,396,247.274	- 4.20 %
12	CO_2-E	1,476,831.872	1,413,697.462	- 4.2 %
13	PM_{10}	482.323	451.573	- 6.38 %
14	$PM_{2.5}$	465.42	431.601	- 7.27 %
15	Lead	0.062	0.0553	- 10.81 %
16	NH_3	6.204	5.528	- 10.90 %
17	N_2O	64.107	57.12	- 10.90 %
18	SO_2	443.344	18.984	- 95.72 %

After conducting the QA/QC system analysis on the completeness of lease operations data, the Team makes the following recommendations:

- Shell Gulf of Mexico Inc.: Remove any leases in OCS AQS related to decommissioning because these activities are not captured in the definition of a facility.
- Shell Offshore Inc.: Remove any leases in OCS AQS related to decommissioning because these activities are not captured in the definition of a facility.
- Operating companies listed in the "Companies with Missing Leases that Did Not Contact the Team for the 2021 Effort" and "Non-responsive Operators with Accounts in OCS AQS" tables: Reach out to the Team for assistance in accessing OCS AQS and complete 2021 submittals.

9.3 Comparison to 2017 Emissions Inventory (Lease Operations)

To identify the trends and conduct further QA/QC, the Team compared the 2017 and 2021 final inventories (emissions inventory after incorporating the corrective actions in Sections 9.1 and 9.2) for lease operations (non-platform) emissions. It should be noted that there are important differences between the 2017 and 2021 final emission inventories, making comparison more challenging. For example, *Year 2017 Emission Inventory Study* presented emissions for other non-platform operations such as helicopters, commercial marine vessels, recreational vessels, and military vessels, among others (Wilson et al. 2019). The 2021 inventory only included emissions from platform and lease operations that are regulated by BOEM based on the definition of a facility as defined by 30 CFR 550.302 (Section 2.3). Table 158 summarizes the non-platform equipment included in the inventory years.

Table 158: Non-platform source types by inventory year

#	Non-platform Source Type	2017 Final	2021 Final
1	Drilling rigs	Yes	Yes
2	Helicopters	Yes	No
3	Pipelaying (Referenced as Platform Construction/Removal) vessels in OCS AQS)	Yes	Yes
4	Support Vessels – Including Well Stimulation Vessel	Yes	Yes
5	Survey vessels	Yes	No

Another significant difference is that 2017 emissions were calculated by BOEM using available data, including vessel activity data from the Automatic Identification System (AIS) and activity data collected by BSEE's Engineering and Operations Division/Operation and Analysis Branch for non-self-propelled drilling rigs (Mathews 2018). However, the 2021 inventory did not utilize this approach and, for the first time, the operators were required to self-report their emissions for the 2021 emissions inventory effort using the new OCS AQS system. With these differences in mind, the following comparisons were made to identify emissions trends between 2017 and 2021 for drilling rigs and support vessels.

> ***NOTE:*** In the 2021 draft inventory, support vessel sources comprised platform construction/removal (PC) activities, whereas in the 2017 final inventory, crew freighting activities to and off the platform were accounted for under the support vessel sources.

9.3.1 Criteria and Precursor Emissions

Table 159 below compares the 2017 and 2021 drilling rigs and support vessels aggregated annual criteria and precursor emissions. It shows that all 2021 non-platform criteria and precursors emission decreased by percentages ranging from 22% to 97%.

The Team broke down the emissions presented in Table 159 by source type (drilling rigs and support vessels) to conduct a deeper investigation on the observed discrepancies (Table 160 and Table 161). Although annual criteria and precursors non-platform emissions decreased in 2021 (Table 159), all criteria and precursors drilling emissions, except for SO_2, increased significantly in the 2021 inventory (Table 160). On the other hand, Table 161 shows an approximately consistent decrease in the criteria pollutants and precursors emissions from support vessels.

Table 159: Comparison of the annual criteria pollutants and precursors drilling rig and support vessel emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Final	% Change
CO	6,541	5,109.68	- 22%
NO_x	28,069	20,906.90	- 26%
PM_{10}	913	451.56	- 51%
$PM_{2.5}$	872	431.60	- 51%
SO_2	736	19.00	- 97%
VOC	716	287.00	- 60%
NH_3	9	5.53	- 39%
Pb	0.1271	0.06	- 57%

Table 160: Comparison of annual criteria pollutants and precursors drilling rig emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Final	% Change
CO	1,320	4,597.11	+ 248%
NO_x	6,418	18,974.13	+ 196%
PM_{10}	148	416.1	+ 181%
$PM_{2.5}$	141	401.76	+ 185%
SO_2	142	12.00	- 92%
VOC	213	237.75	+ 12%
NH_3	3	5.53	+ 84%
Pb	2.31E-02	5.53E-02	+ 139%

Table 161: Comparison of the annual criteria pollutants and precursors support vessel emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Final	% Change
CO	5,221	513	- 90%
NO_x	21,651	1,933	- 91%
PM_{10}	765	35	- 95%
$PM_{2.5}$	731	30	- 96%
SO_2	594	7	-99%
VOC	503	49	-90%
NH_3	6	0	-100%
Pb	0	0	-100%

To further investigate the reasons for the increase in the 2021 drilling emissions and the decrease in the 2021 support vessels emissions, the Team compared the count of the drilling rigs and support vessels reported in the *Year 2017 Emission Inventory Study* against the count in the 2021 final inventory in OCS

AQS (Wilson et al. 2019). The count of drilling rigs increased by 68.27% in the 2021 final inventory, while the support vessels count decreased by 74.61% (Table 162). Therefore, the increase of the 2021 criteria and precursors drilling emissions, except for SO_2, directly resulted from the increase in the number of reported drilling rigs in 2021. Similarly, the decrease in the 2021 criteria and precursors emissions from support vessels was because of the 74.61% decrease in the count of those vessels in 2021. The drop in the count of reported supporting vessels in the 2021 draft was expected since, unlike the 2017 final inventory, the 2021 draft inventory did not account for crew freighting activities to and off the platform under support vessel sources because this was not under the 2021 definition for facility.

> ***NOTE:*** The decrease in SO_2 drilling emissions could have resulted from the operators revising their incorrectly entered high values of sulfur content (Section 9.1.2). Since the 2017 drilling activity data was not provided, the Team was not able to compare the 2021 drilling rigs' fuel sulfur content values against the 2017 values. In addition, the decrease in SO_2 emissions also could have resulted from using only ultra-low sulfur fuels in 2021.

Table 162: Comparison of the count of drilling rigs and support vessels by inventory year with % change

#	Non-platform Source Type	2017 Final	2021 Final	% Change
1	Drilling rigs	104	175	+ 68.27%
2	Support Vessels – Including Well Stimulation Vessel	1,107	281	- 74.61%

> ***NOTE:*** In the 2021 draft inventory, support vessel sources comprised the platform construction/removal (PC) activities, whereas in the 2017 final inventory, crew freighting activities to and off the platform were accounted for under the support vessel sources.

9.3.2 GHG Emissions

Table 163 compares the 2017 and 2021 aggregated annual GHG emissions for drilling rigs and support vessels. It shows that all 2021 non-platform GHG emissions increased by percentages ranging from 39% to 328%.

The Team broke down the emissions presented in Table 163 by source type (drilling rigs and support vessels) to investigate the observed dependencies between the 2017 and 2021 inventory years. Therefore, Table 164 and Table 165 compare the GHG emissions by drilling rigs and support vessels, respectively.

Although the annual GHG non-platform emissions increased in 2021 (Table 163), GHG support vessels emissions decreased significantly in the 2021 inventory, except for CH_4 (Table 165). On the other hand, Table 164 shows an excessive increase in GHG emissions for drilling rigs. Data presented in Table 162 can explain that the increase in GHG drilling emissions directly resulted from the increase in the number of reported drilling rigs in 2021. Similarly, the decrease in the 2021 GHG support vessel emissions, except for CH_4 (Table 165), was because of the 74.61% decrease in the count of those vessels in 2021.

Table 163: Comparison of drilling rigs and support vessel GHG emission (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Final	% Change
CO_2	778,874	1,395,880.054	+ 79%
CH_4	4	17.13	+ 328%
N_2O	41	57.12	+ 39%
CO_2-E	791,150	1,413,153.41	+ 79%

Table 164: Comparison of drilling rig GHG emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Final	% Change
CO_2	508,797.00	1,296,440.29	+ 155%
CH_4	3.00	12.34	+ 311%
N_2O	26.00	57.12	+ 120%
CO_2-E	516,469.0	1,313,607.01	+ 154%

Table 165: Comparison of GHG support vessel emissions (tons/year) by inventory year with % change

Pollutant	2017 Final	2021 Final	% Change
CO_2	270,077.00	99,439.76	- 63%
CH_4	1.00	4.79	+ 379%
N_2O	15.00	0.0	- 100%
CO_2-E	274,681.00	99,546.40	- 64%

9.3.3 Lease Operations (Non-Platform) Emissions Inventory Changes

Table 166 provides a list of non-platform source types that reported 2021 emissions.

Table 166: Description of source types that reported 2021 lease operation emissions

Source ID	Source Type	Source Description
CSV-PC	Platform Construction/Removal (PC)	Installation Operations
DRI-Crude	Drilling (DR)	Drilling Rig for Crude Oil Exploration/Production Wells
DRI-NG	Drilling (DR)	Drilling Rig, Natural Gas Exploration and Production Wells
CSV-WS	Well Stimulation Vessel (WS)	Well Stimulation
DRI-SP-4N	Drilling (DR)	Self Propelled Drill Rig - Foreign Flagged
DRI-SP-DOM	Drilling (DR)	Self Propelled Drill Rig - US Flagged (Domestic)

OCS AQS provided emission calculators for the following lease operation equipment types:

- Diesel Engines Where Max HP => 600
- Diesel Engines Where Max HP is less than 600
- Crude Oil Production Well Drilling - Diesel Engine
- Natural Gas Production Well Drilling - Diesel Engine
- Drilling from C1/C2 Vessels (Foreign flagged)
- Drilling from C1/C2 Vessels (U.S. flagged)

Based on review of the 2021 non-lease activities and equipment that reported emissions, it was noted that several equipment types for which the emissions were previously calculated in the 2017 inventory were not reported in 2021:

- Prime engines
- Mud pumps
- Draw works
- Emergency power

As this was the first year that operators had to self-report their emissions, operators may not have known that emissions from these equipment types should have been reported. To better define which equipment types must report emissions for future emission inventories, OCS AQS will be modified to specifically ask operators to report emissions for these source types. Updates to OCS AQS will include the ability for users to select these equipment types and enter the necessary activity data to calculate emissions based on the equations presented in the *Year 2017 Emissions Inventory Study*. In addition, it may be possible in the future to integrate BOEM's eWell database into OCS AQS, and known drilling rig activity data would be prepopulated in the operators' inventories. This way, operators would have a list of known permitted drilling rig activities and simply need to enter refined information, such as actual move on and move off dates, as well as other activity data used to calculate emissions.

10 Recommendations and Future Implementation

Based on the completion of QA/QC tasks and a detailed review of the 2021 draft emissions inventory, the Team implemented the following recommendations to improve OCS AQS and future inventory efforts:

- Additional baseline QA/QC: The Team identified certain errors that were repeatedly observed in the 2021 draft inventory. These include, for example, exceeding the maximum number of days and hours in each month, which OCS AQS can check automatically based on the user input. In future reporting cycles, OCS AQS will require the hours or days of operation per month for all equipment types. Automatic QA checks will alert users when the number of operating hours exceed the maximum number of hours within a month, considering the number of actual days in any given month. In addition, copying operational hours and days from month to month will be prohibited; these values will need to be entered manually.
- Automated system QA/QC ranges will be reviewed and adjusted based on 2021 final data to further reduce instances of unrealistic or erroneous activity data.
- OCS AQS now uses a new anomaly detector tool to help users perform checks and analyses before submitting their data. This tool allows the user to set percentage boundaries from the 12-month average and detects any non-zero values that fall outside this defined range. The tool will highlight anomalies and help users identify inconsistencies or mistyped values in activity data. This tool will ensure greater accuracy of the submitted data in future reporting cycles.
- New data entry hints in the data and control request fields in the Activity and Emissions Manager provide better clarity regarding the requested data. The hints also will emphasize the measurement unit of the requested field to avoid confusion like the one that caused an overestimation of SO_2 calculated emissions.
- A new throughput descriptive statistics tool will help operators perform checks before submitting throughput data. This tool will list the selected equipment's mean, maximum, minimum, and total throughput.
- OCS AQS will require the submission of sales gas composition for all facilities to avoid any calculation issues.

These recommendations **will need to be made** to improve OCS AQS and future inventory efforts:

- Comparison of volume vented and flared with the Office of Natural Resources Revenue (ONRR) Oil and Gas Operations Report (OGOR) values is under consideration as the Team continues to receive feedback from BOEM and operators.
- Drilling rig QA/QC: As this was the initial year operators were required to provide lease operations data, there may have been some misalignment of expectations between BOEM and operators, resulting in data gaps (Section 9.2). The Team will support various actions, in consultation with BOEM, to improve the data quality, including Frequently Asked Question updates and additional feature implementation in OCS AQS.
- To improve lease operation emissions, update OCS AQS to specifically ask operators to report emissions for prime engines, mud pumps, draw works, and emergency power equipment types.
- Integrate eWell into OCS AQS to provide operators with a prepopulated inventory of drilling activities.

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Appendix A – OPD Area Abbreviation Key

OPD Area Abbreviation	OPD Area Name
BM	Bay Marchand
BA	Brazos
BS	Breton Sound
CA	Chandeleur
DM	Federal Waters
EB	East Breaks
EC	East Cameron
EI	Eugene Island
EW	Ewing Bank
GA	Galveston
GB	Garden Banks
GI	Grand Isle
GC	Green Canyon
HI	High Island
MP	Main Pass
MI	Matagorda Island
AC	Alaminos Canyon
MC	Mississippi Canyon
MO	Mobile
MU	Mustang Island
PN	North Padre Island
SA	Sabine Pass (Louisiana)
SS	Ship Shoal
SM	South Marsh Island
SP	South Pass
PL	South Pelto
ST	South Timbalier
VR	Vermilion
VK	Viosca Knoll
WR	Walker Ridge
WC	West Cameron
WD	West Delta
KC	Keathley Canyon
PE	Pensacola
PS	South Padre Island
SX	Sabine Pass (Texas)
SE	Sigsbee Escarpment
LL	Lloyd Ridge
FP	Florida Plain
DD	Destin Dome
CC	Corpus Christi
AM	Amery Terrace
AT	Atwater Valley
LS	Lund South

OPD Area Abbreviation	OPD Area Name
PI	Port Isabel
LU	Lund
DC	De Soto Canyon
HE	Henderson
DT	Dry Tortugas
AP	Apalachicola
BA_S	Brazos, South Addition
CA_E	Chandeleur, East Addition
CE	Campeche Escarpment
CH	Charlotte Harbor
EC_S	East Cameron, South Addition
EI_S	Eugene Island, South Addition
EL	The Elbow
FM	Florida Middle Ground
GA_S	Galveston, South Addition
GI_S	Grand Isle, South Addition
GV	Gainesville
HH	Howell Hook
HI_ES	High Island, East Addition, South Extension
HI_S	High Island, South Addition
HI_E	High Island, East Addition
KW	Key West
MA	Miami
MP_SE	Main Pass, South and East Addition
MU_E	Mustang Island, East Addition
NO	New Orleans
PB	St. Petersburg
PN_E	North Padre Island, East Addition
PR	Pulley Ridge
PS_E	South Padre Island, East Addition
RK	Rankin
SM_S	South Marsh Island, South Addition
SM_N	South Marsh Island, North Addition
SP_SE	South Pass, South and East Addition
SS_S	Ship Shoal, South Addition
ST_S	South Timbalier, South Addition
TP	Tarpon Springs
TV	Tortugas Valley
VN	Vernon Basin
VR_S	Vermilion, South Addition
WC_S	West Cameron, South Addition
WC_W	West Cameron, West Addition
WD_S	West Delta, South Addition
CS	Chukchi Sea
BF	Beaufort Sea
HB	Hope Basin

A map of OPD areas in the GOM is displayed in Figure A - 1.

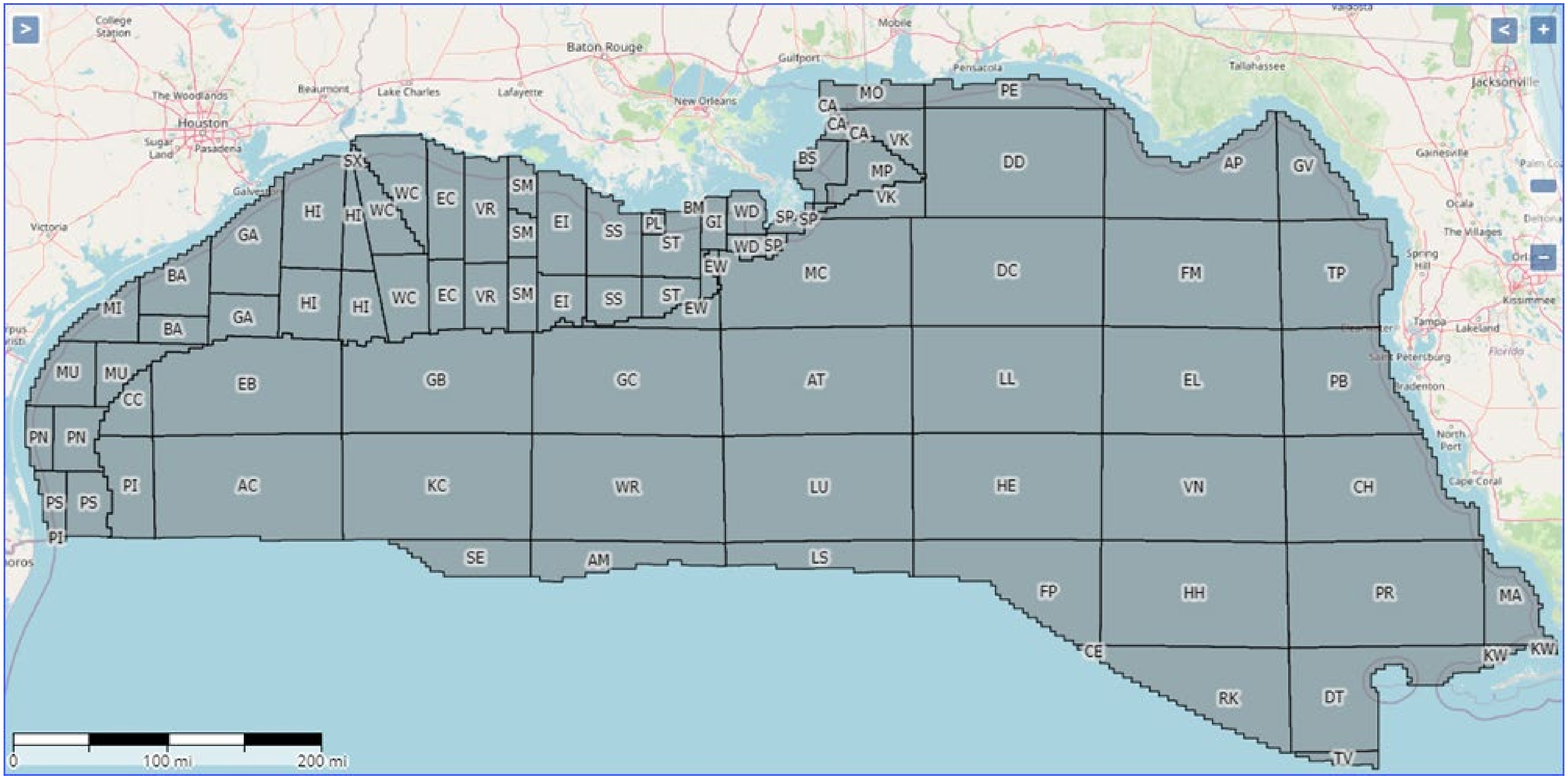

Figure A - 1: OPD areas in the GOM

Appendix B – 2021 Final Platform Gridded Emissions

This section presents the platform gridded emissions as generated by OCS AQS based on the emissions data in the 2021 final inventory (for lease operations gridded emissions, see Appendix C).

Figure B - 1 shows the distribution of the platform structures in the GOM. The image shows the entire region, and it is evident that platforms are concentrated in areas south of Louisiana.

> ***NOTE:*** If multiple platforms are near each other, their markers will be aggregated under a single one with a number indicating the number of structures that marker represents.

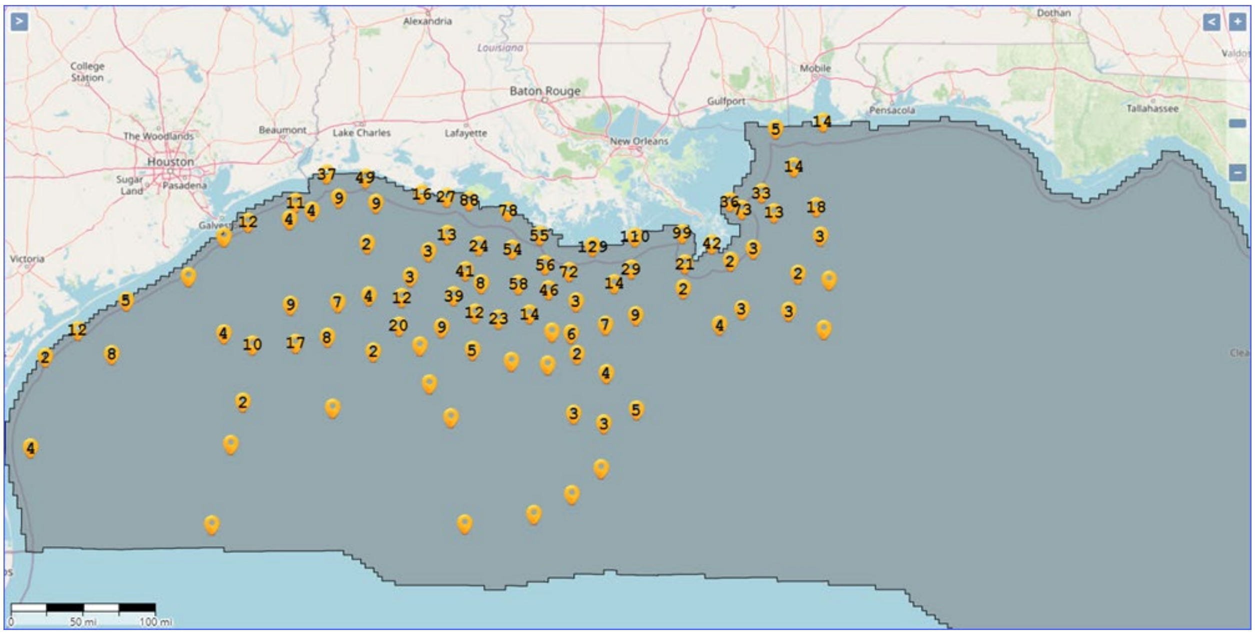

Figure B - 1: Distribution of platforms in the GOM in 2021

The settings used to generate the gridded emissions in this section are as follows (some of the information below is available in the color legend in each figure):

- Emissions: Platform
- Grid Type: OCS Blocks
- Emission Units: Tons
- Period: Annual (January to December)
- Method: Facility (combined facility emissions are centered on the platform coordinates)
- # of Levels: 10
- Equipment Type: All

The following figures display the 2021 final platform gridded emissions for the GHG pollutants:

- Figure B - *2*: 2021 final platform CO_2 annual emissions (tons) in the GOM region
- Figure B - *3*: 2021 final platform CH_4 annual emissions (tons) in the GOM region
- Figure B – *4*: 2021 final platform N_2O annual emissions (tons) in the GOM region
- Figure B - *5*: 2021 final platform CO_2-E annual emissions (tons) in the GOM region

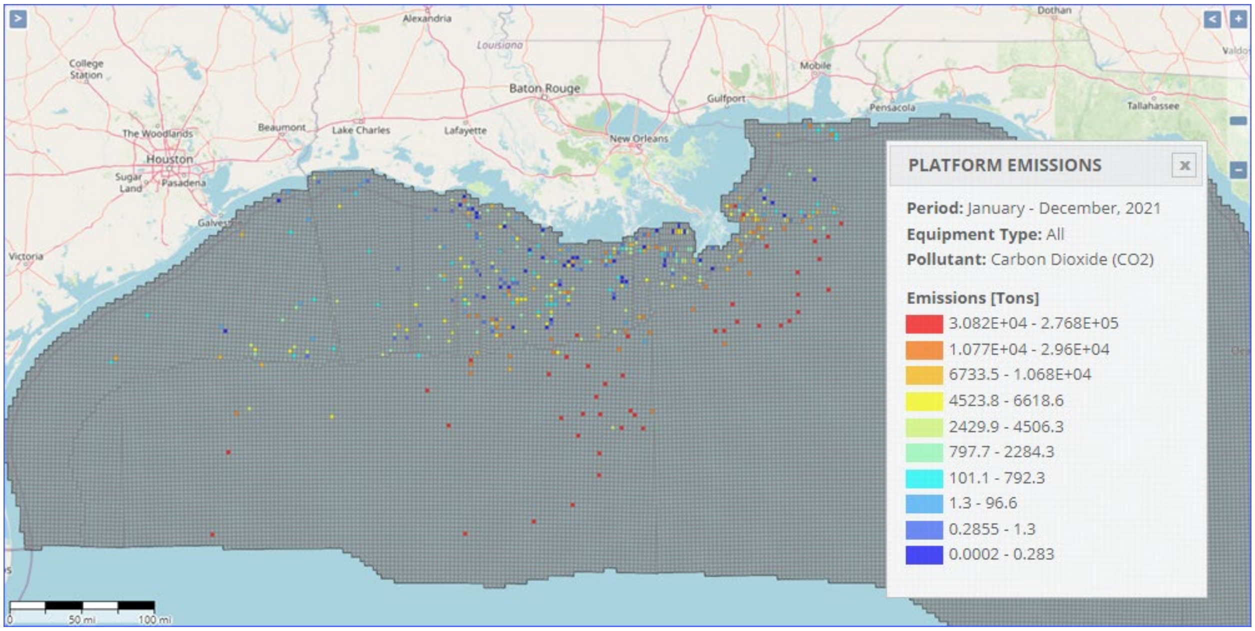

Figure B - 2: 2021 final platform CO_2 annual emissions (tons) in the GOM region

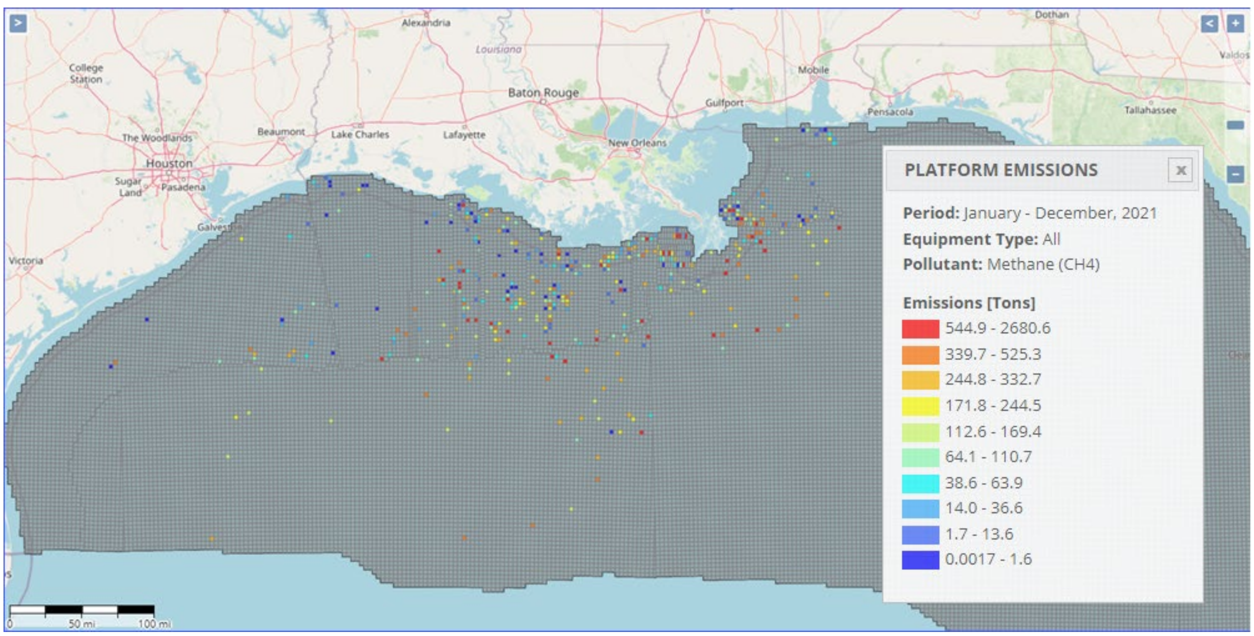

Figure B - 3: 2021 final platform CH_4 annual emissions (tons) in the GOM region

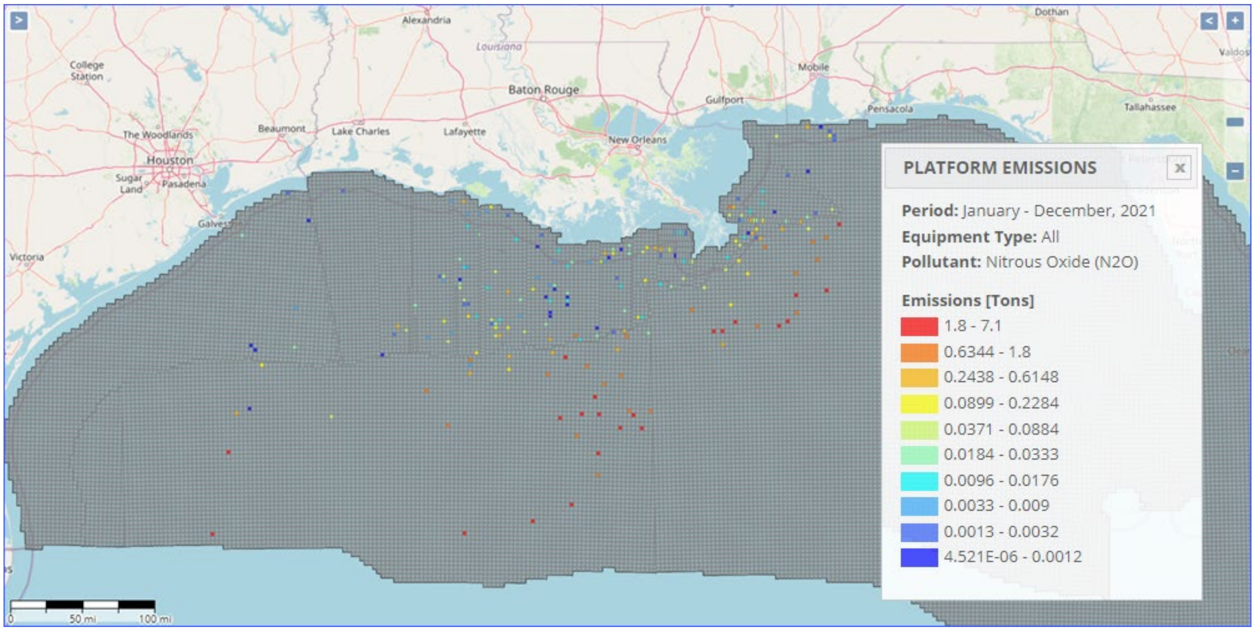

Figure B – 4: 2021 final platform N_2O annual emissions (tons) in the GOM region

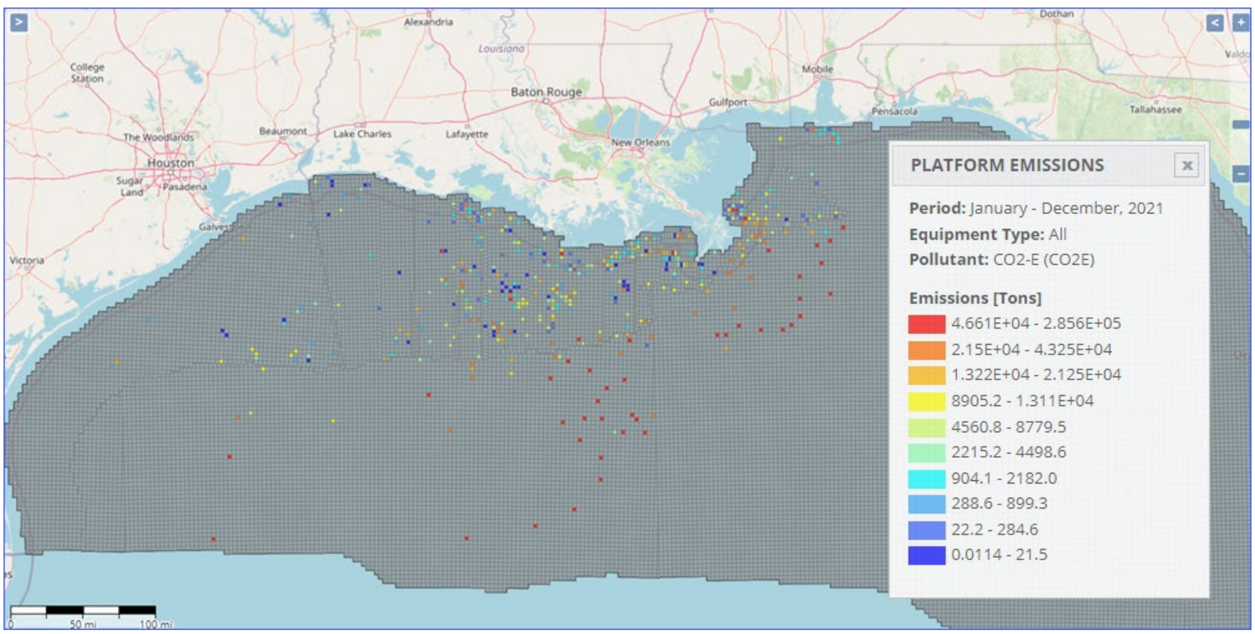

Figure B - 5: 2021 final platform CO_2-E annual emissions (tons) in the GOM region

The following figures display the 2021 final platform gridded emissions for criteria pollutants:

- Figure B - *6*: 2021 final platform NH_3 annual emissions (tons) in the GOM region
- Figure B - *7*: 2021 final platform CO annual emissions (tons) in the GOM region
- Figure B - *8*: 2021 final platform Pb annual emissions (tons) in the GOM region
- Figure B - *9*: 2021 final platform NOx annual emissions (tons) in the GOM region
- Figure B - *10*: 2021 final platform PM_{10} annual emissions (tons) in the GOM region
- Figure B - *11*: 2021 final platform $PM_{2.5}$ annual emissions (tons) in the GOM region

- Figure B - *12*: 2021 final platform SO_2 annual emissions (tons) in the GOM region
- Figure B – *13*: 2021 final platform VOC annual emissions (tons) in the GOM region

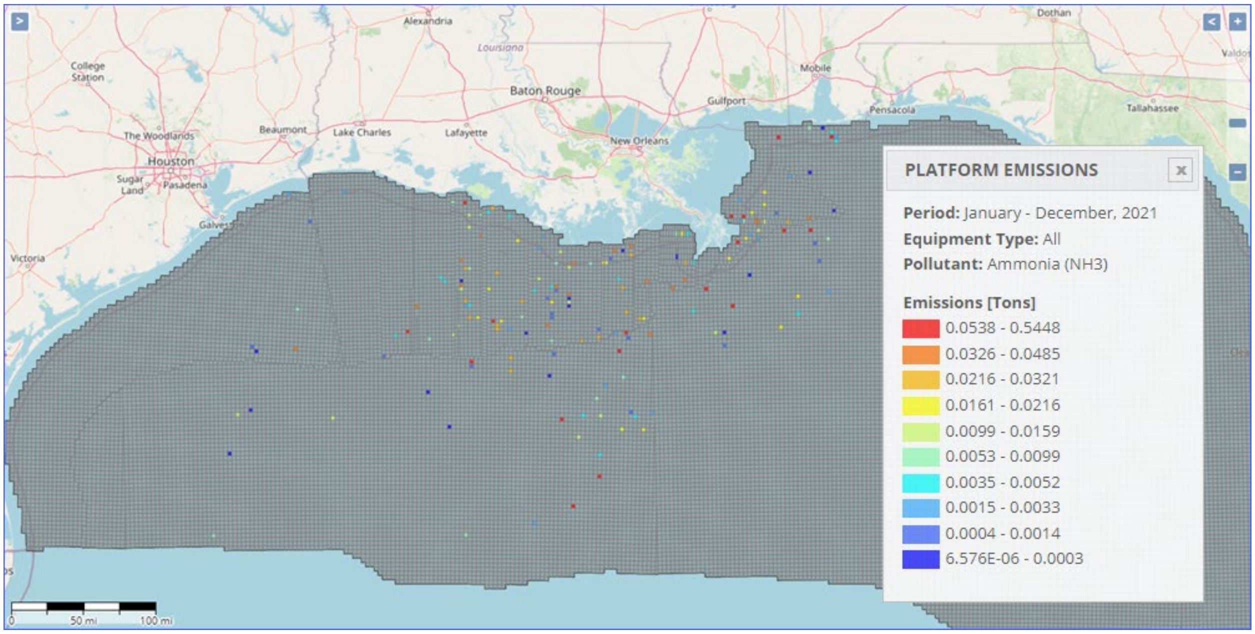

Figure B - 6: 2021 final platform NH_3 annual emissions (tons) in the GOM region

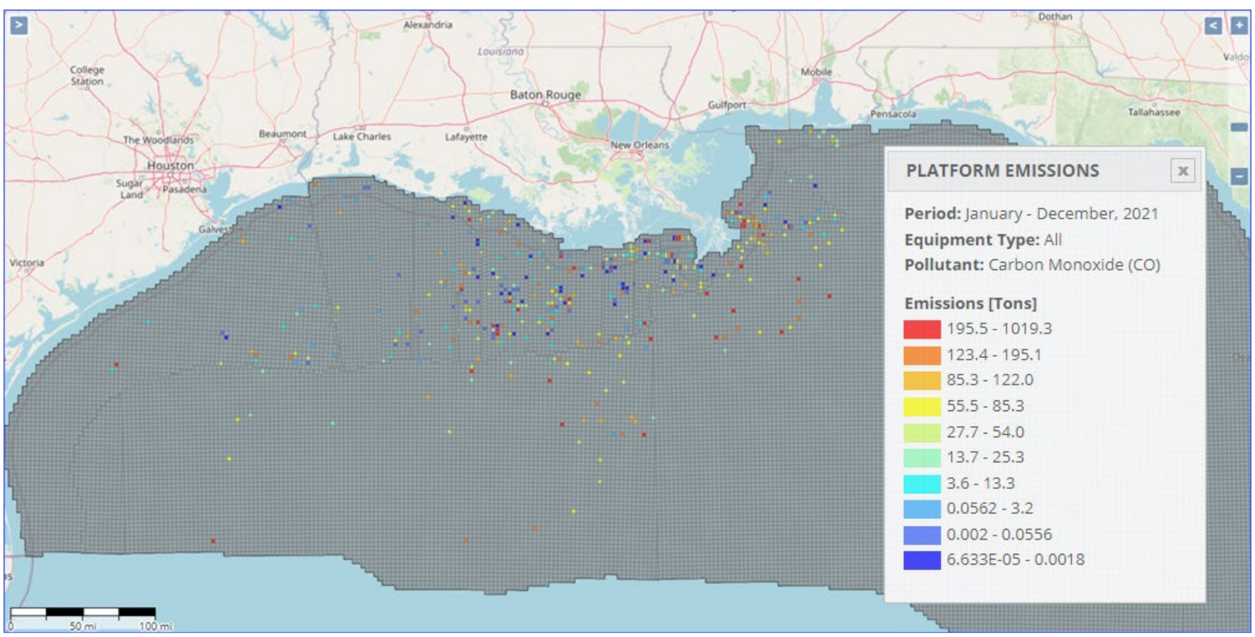

Figure B - 7: 2021 final platform CO annual emissions (tons) in the GOM region

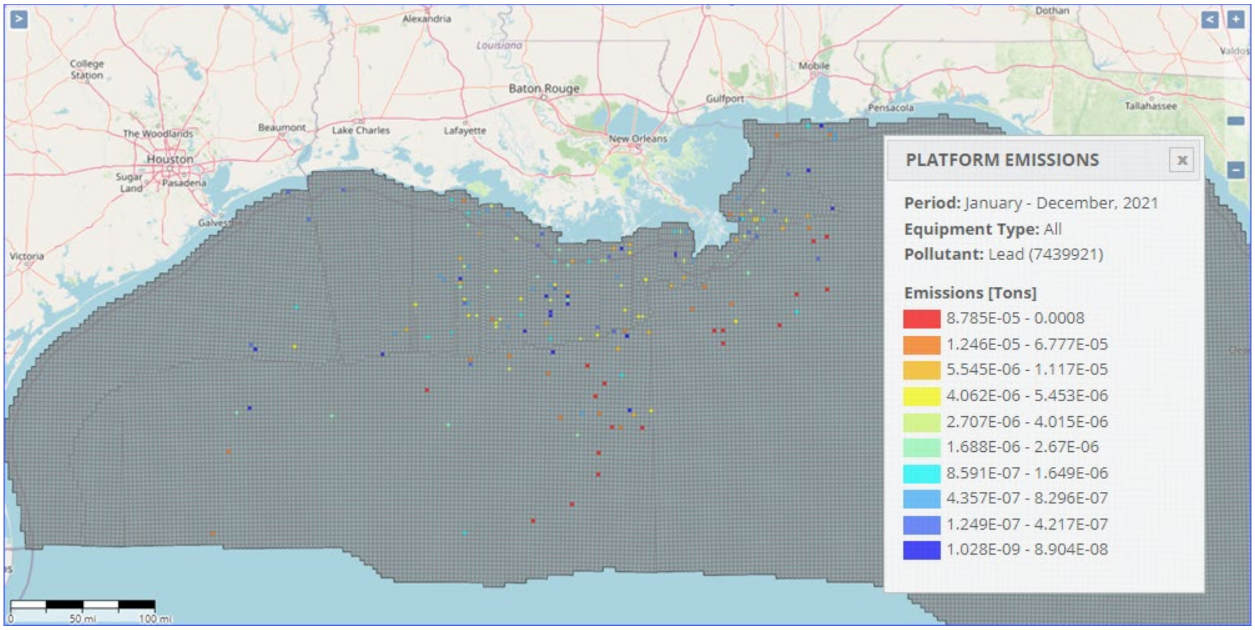

Figure B - 8: 2021 final platform Pb annual emissions (tons) in the GOM region

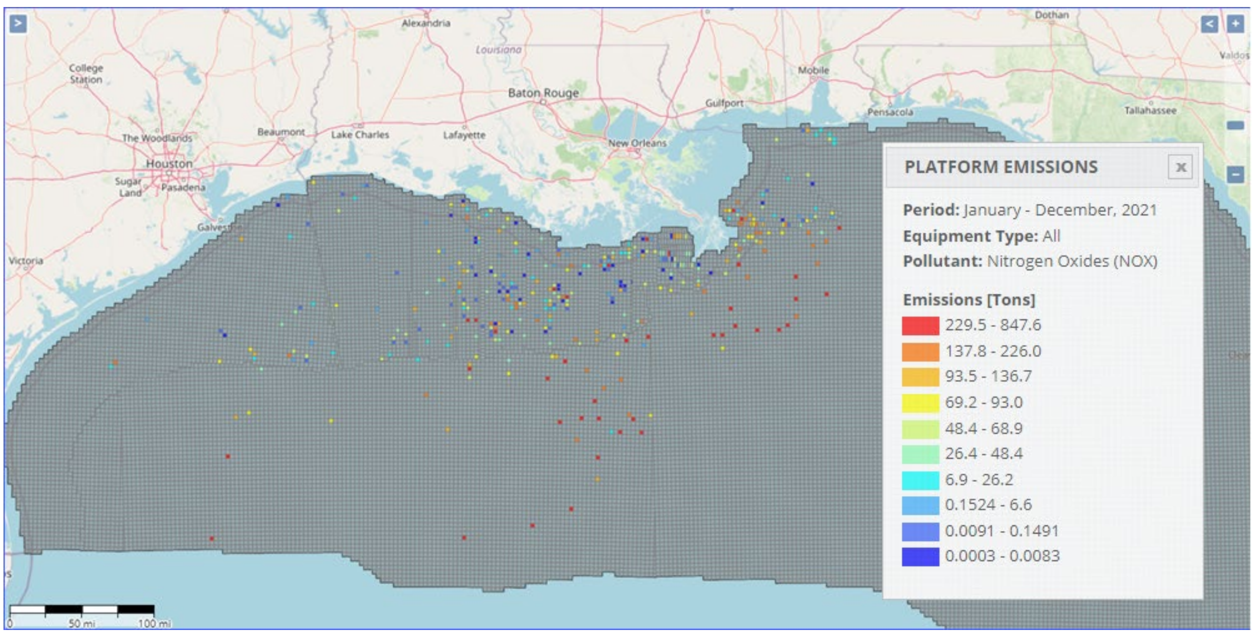

Figure B - 9: 2021 final platform NO_x annual emissions (tons) in the GOM region

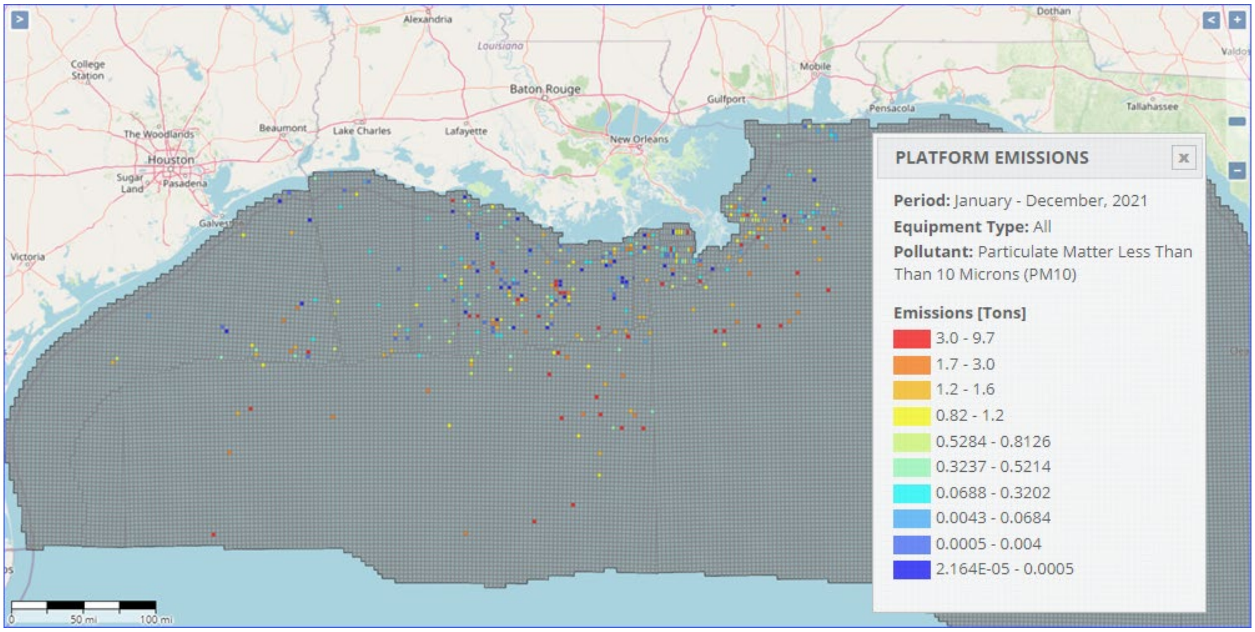

Figure B - 10: 2021 final platform PM_{10} annual emissions (tons) in the GOM region

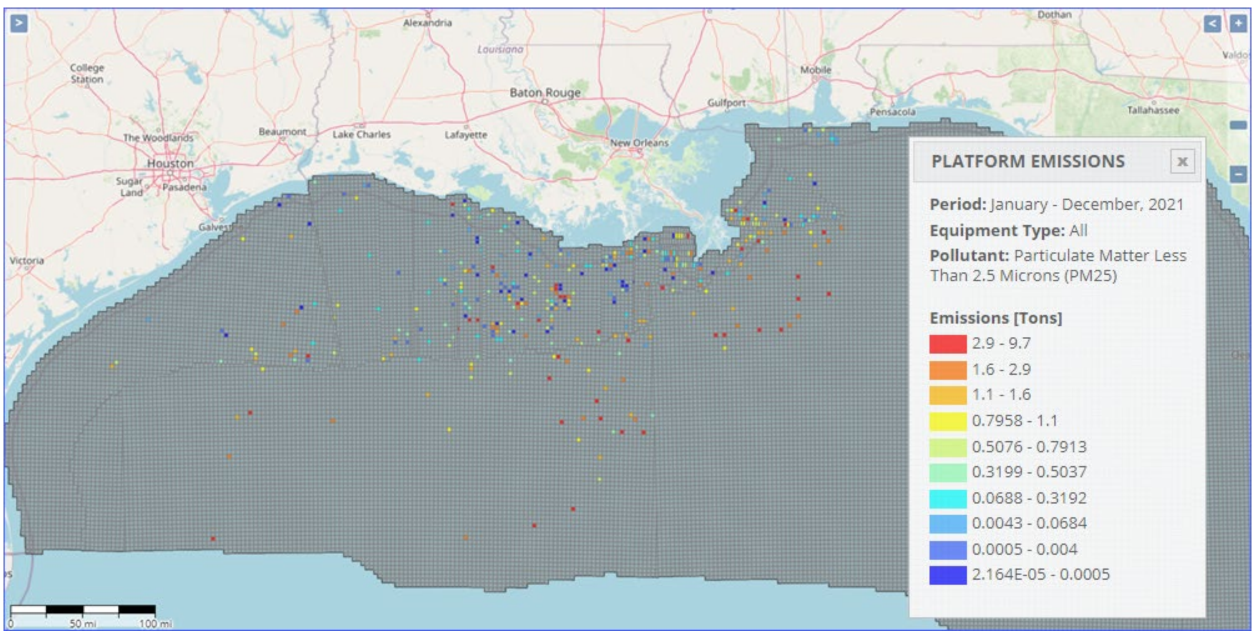

Figure B - 11: 2021 final platform $PM_{2.5}$ annual emissions (tons) in the GOM region

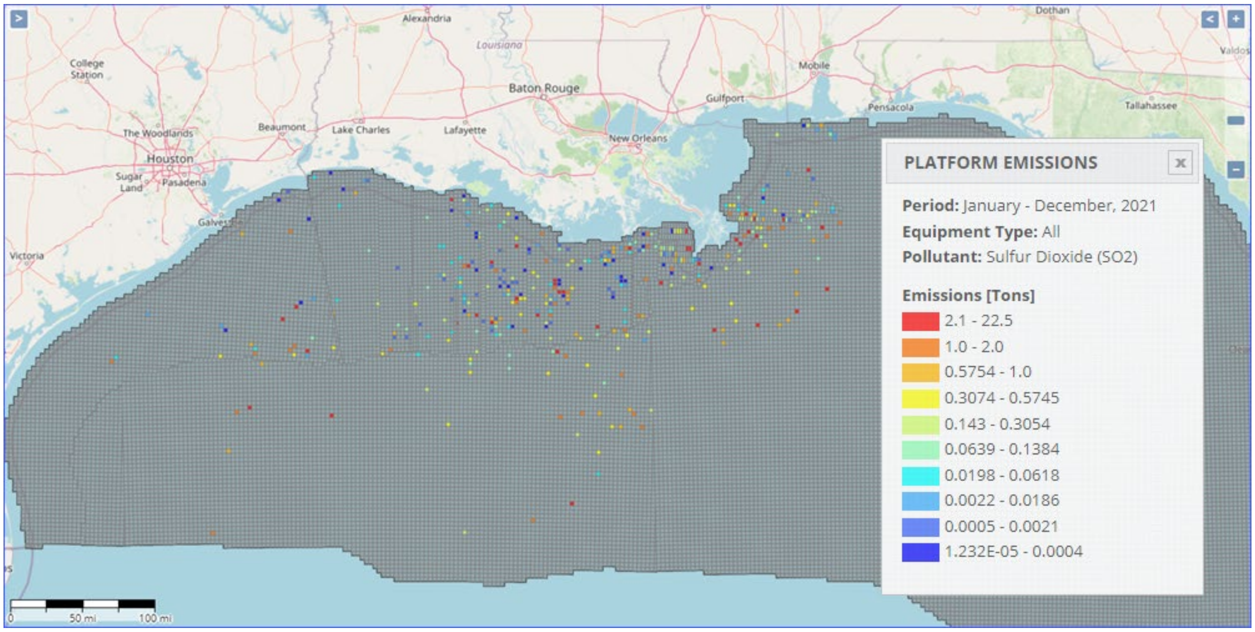

Figure B - 12: 2021 final platform SO_2 annual emissions (tons) in the GOM region

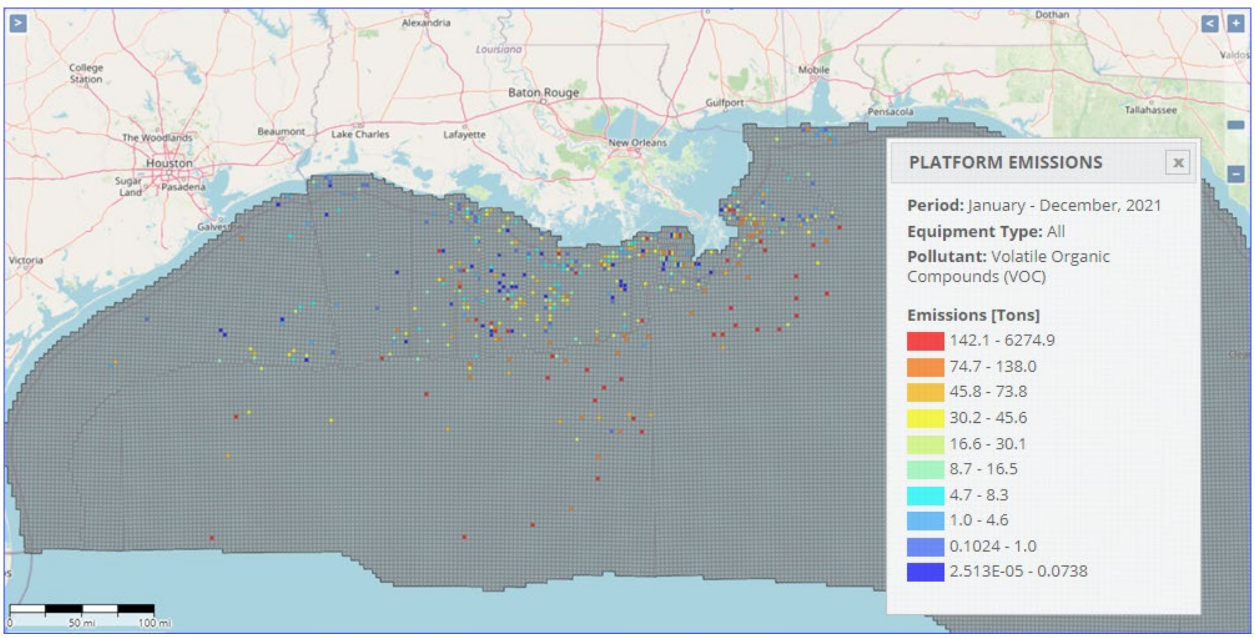

Figure B – 13: 2021 final platform VOC annual emissions (tons) in the GOM region

Appendix C – 2021 Final Lease Operations Gridded Emissions

This section presents the gridded emissions as generated by OCS AQS based on the lease operations emissions data in the 2021 final inventory (for platform gridded emissions, see Appendix B).

Figure C - 1 shows the distribution of the lease operations in the GOM. The image shows the entire region, and it is evident that lease operations are concentrated south of Louisiana.

> **NOTE:** If multiple lease operations are near each other, their markers will be aggregated under a single one with a number indicating the number of lease operations that marker represents.

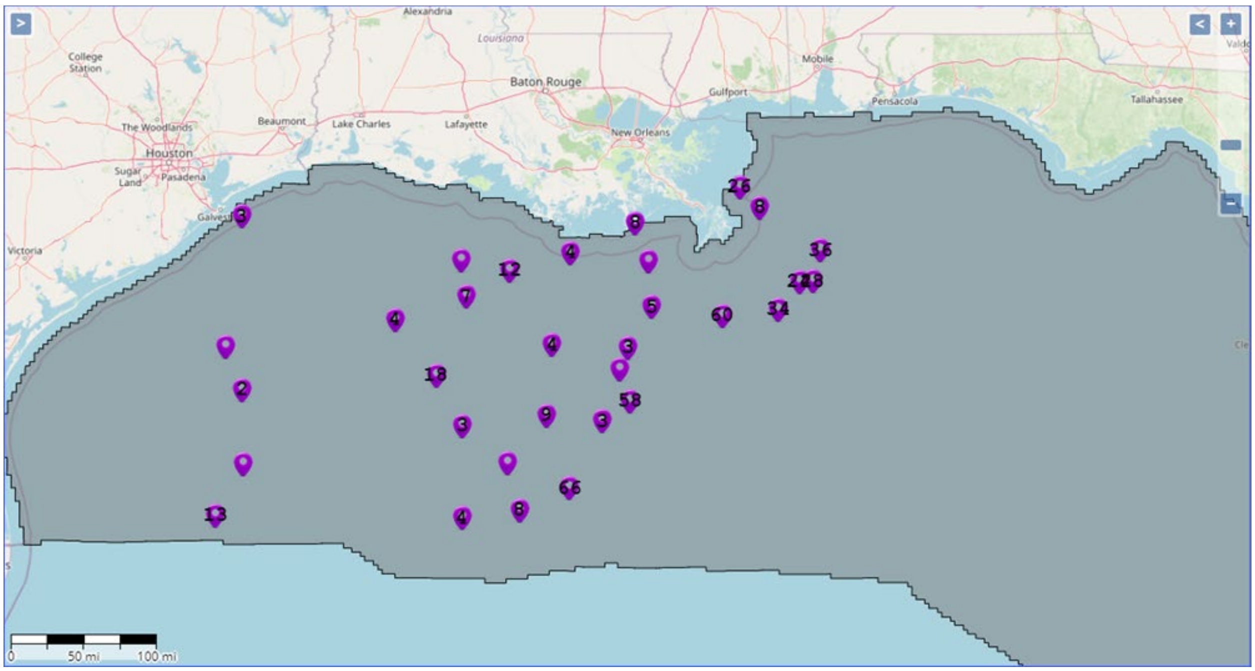

Figure C - 1: Distribution of lease operations in the GOM

The settings used to generate the gridded emissions in this section are as follows (some of the information below is available in the color legend in each figure):

- Emissions: Lease Operations
- Grid Type: OCS Blocks
- Emission Units: Tons
- Period: Annual (January to December)
- # of Levels: 10

The following figures display the 2021 final lease operations gridded emissions for the GHG pollutants:

- Figure C - 2: 2021 final lease operations CO_2 annual emissions in the GOM Region
- Figure C - 3: 2021 final lease operations CH_4 annual emissions in the GOM Region
- Figure C - 4: 2021 final lease operations N_2O annual emissions in the GOM Region
- Figure C - 5: 2021 final lease operations CO_2-E annual emissions in the GOM Region

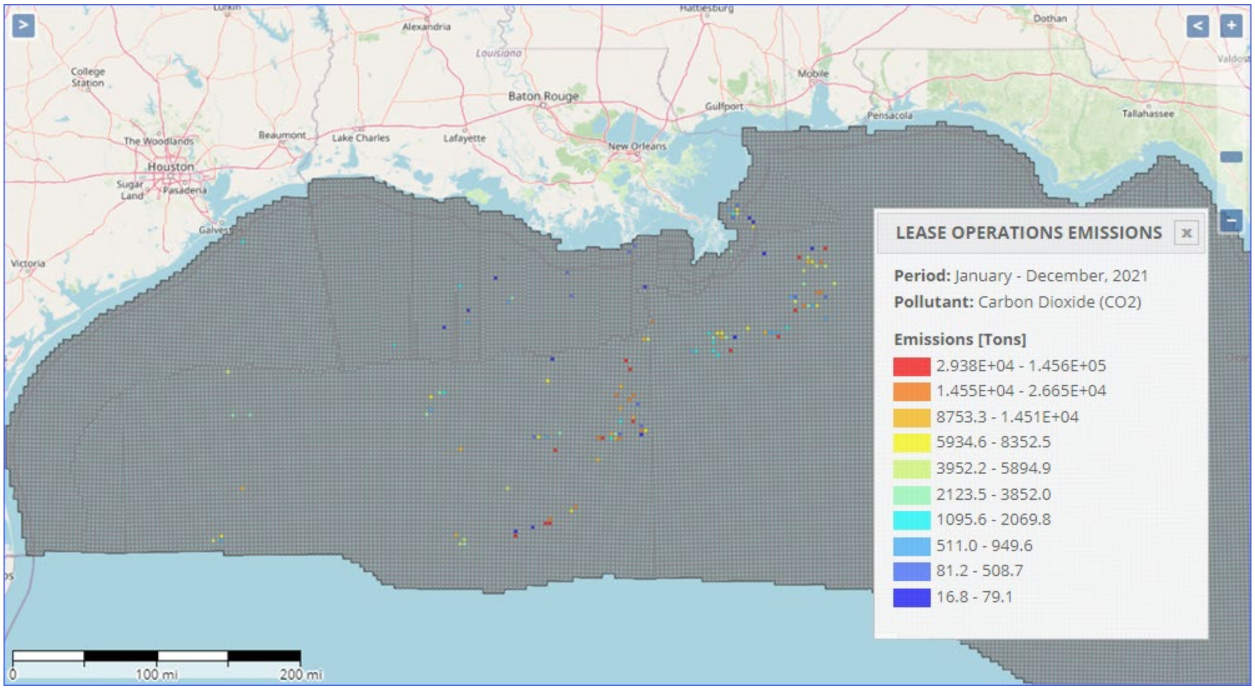

Figure C - 2: 2021 final lease operations CO_2 annual emissions in the GOM Region

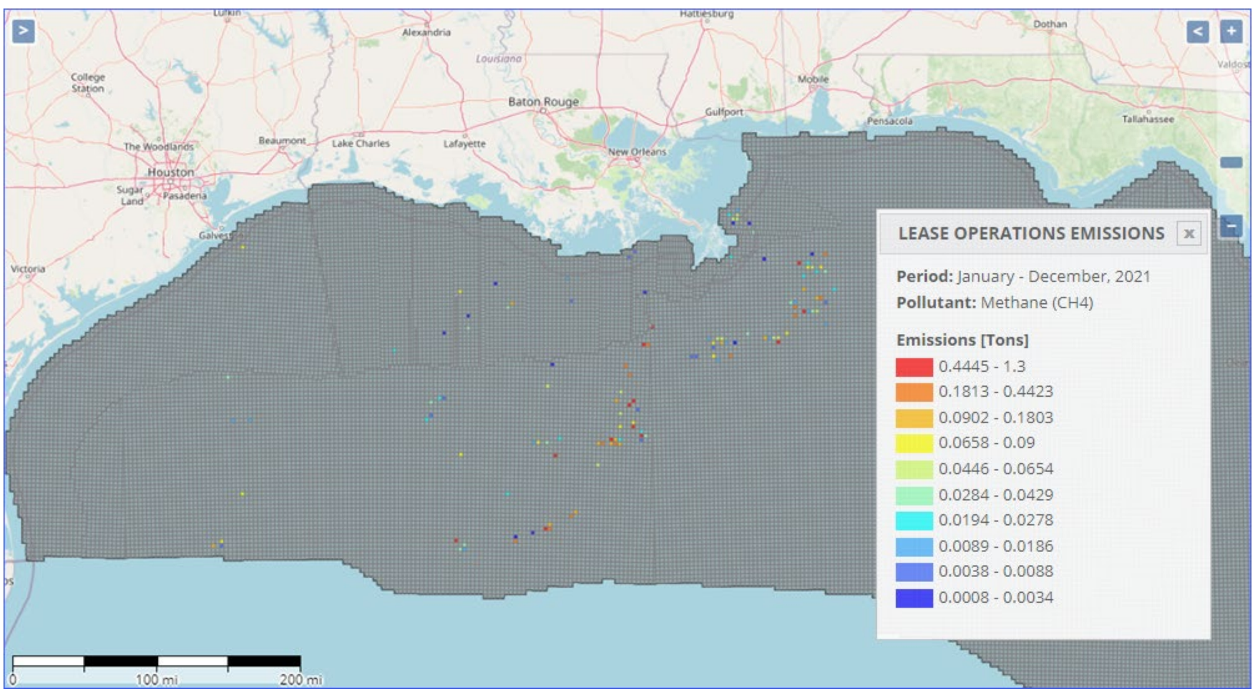

Figure C - 3: 2021 final lease operations CH_4 annual emissions in the GOM Region

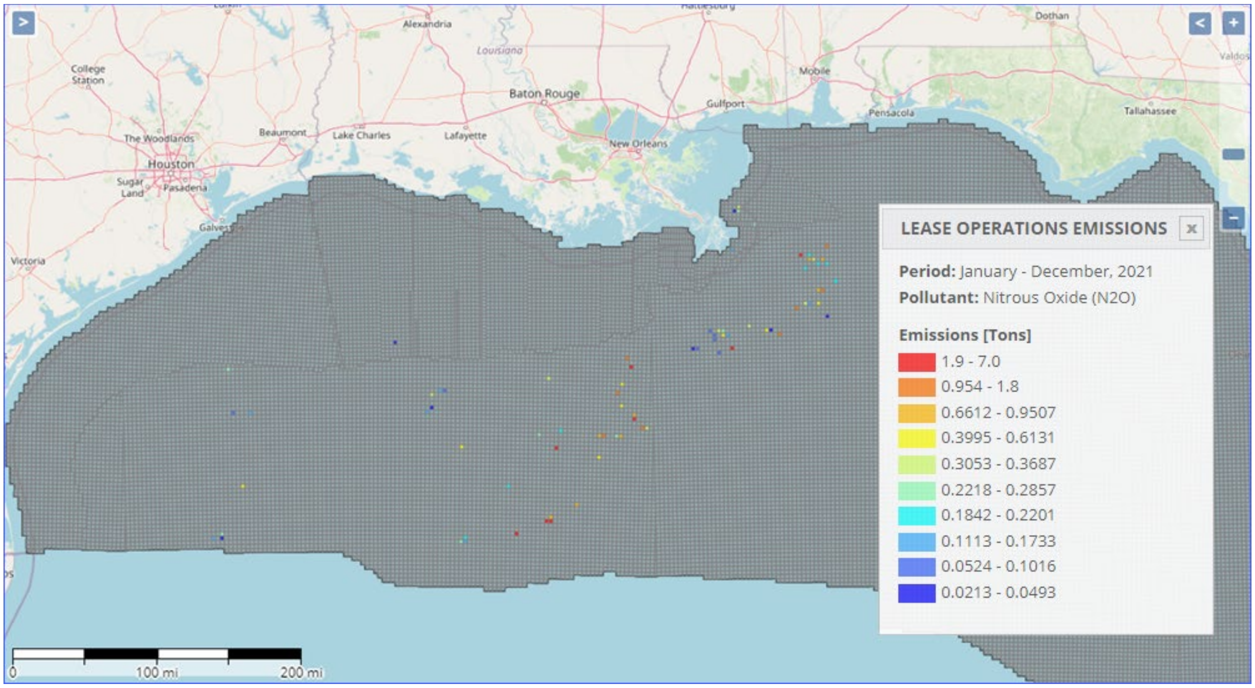

Figure C - 4: 2021 final lease operations N_2O annual emissions in the GOM Region

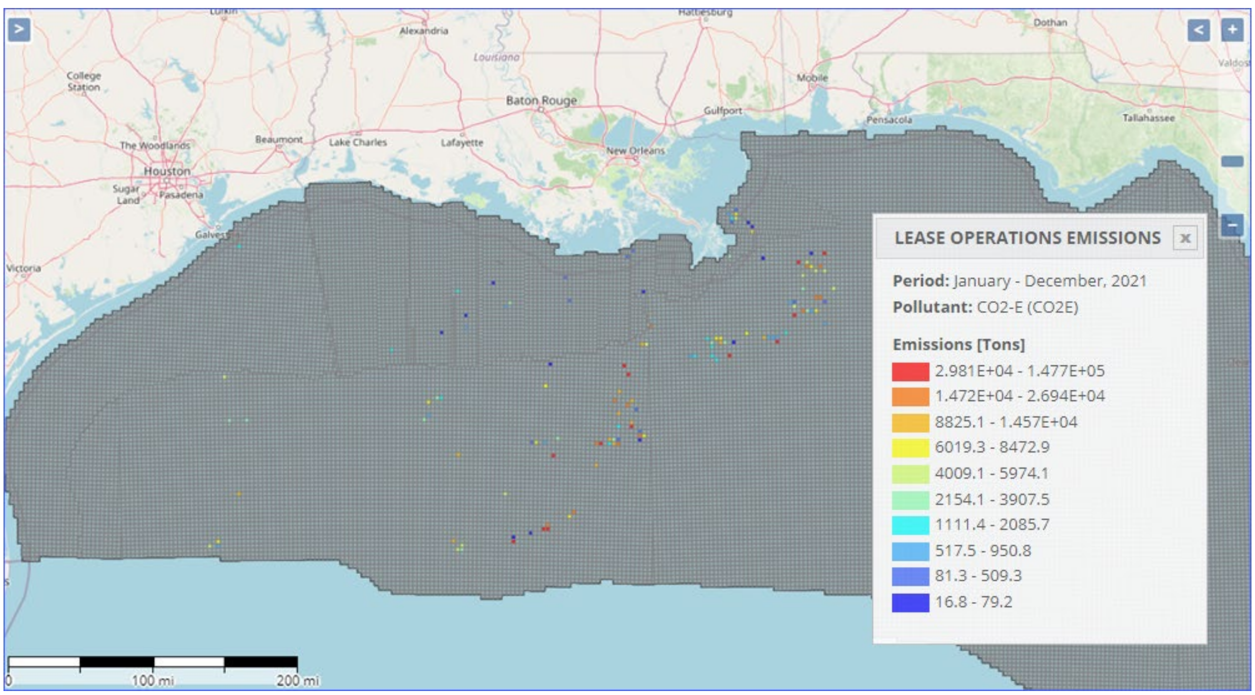

Figure C - 5: 2021 final lease operations CO_2-E annual emissions in the GOM Region

The following figures display the gridded emissions for critical pollutants:

- Figure C - 6: 2021 final lease operations NH_3 annual emissions in the GOM Region
- Figure C - 7: 2021 final lease operations CO annual emissions in the GOM Region
- Figure C - 8: 2021 final lease operations Pb annual emissions in the GOM Region

- Figure C - 9: 2021 final lease operations NOx annual emissions in the GOM Region
- Figure C - 10: 2021 final lease operations PM_{10} annual emissions in the GOM Region
- Figure C - 11: 2021 final lease operations $PM_{2.5}$ annual emissions in the GOM Region
- Figure C - 12: 2021 final lease operations SO_2 annual emissions in the GOM Region
- Figure C - 13: 2021 final lease operations VOC annual emissions in the GOM Region

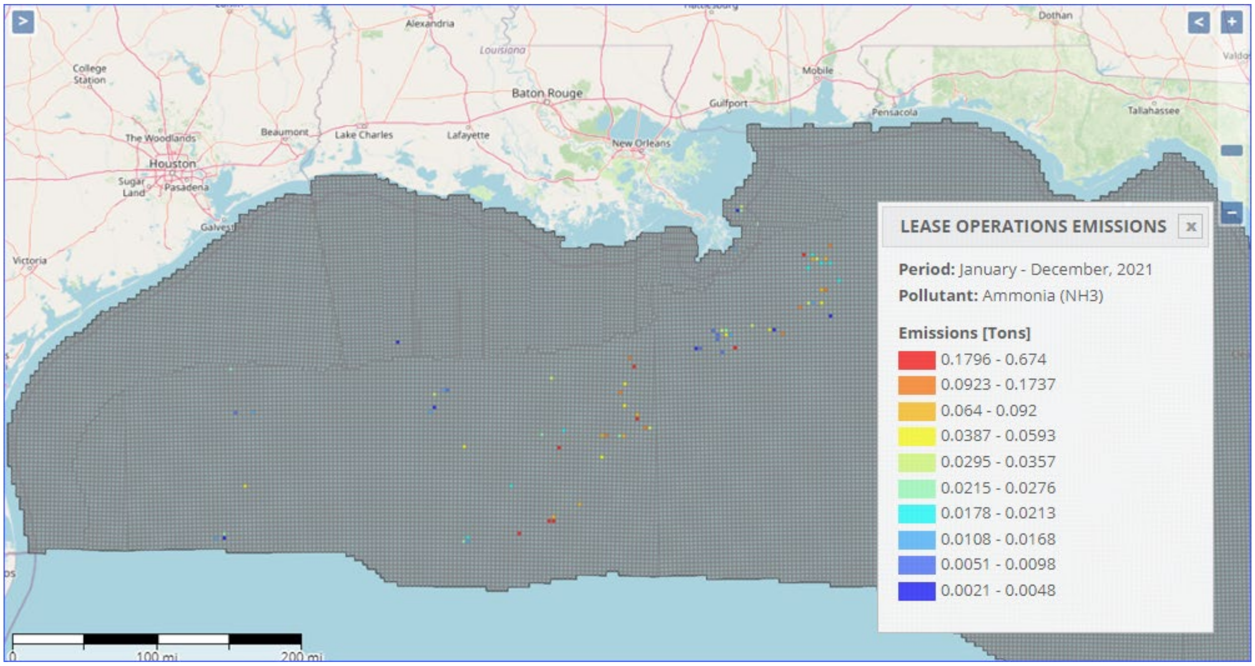

Figure C - 6: 2021 final lease operations NH_3 annual emissions in the GOM Region

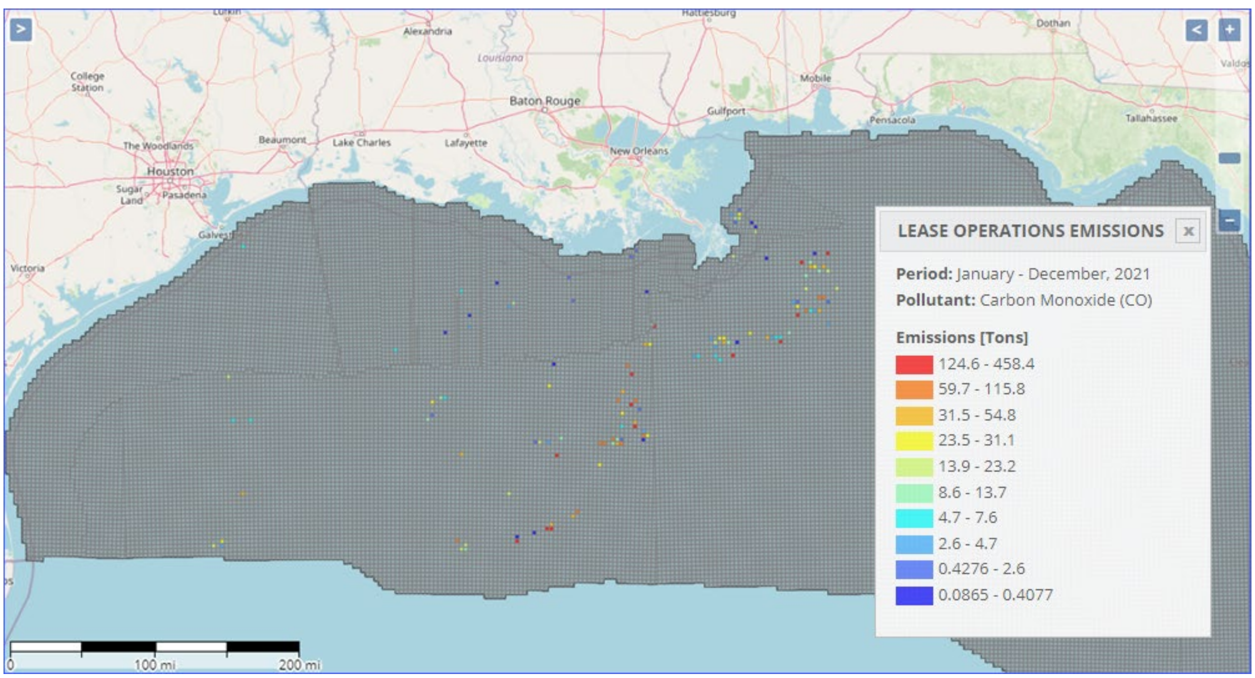

Figure C - 7: 2021 final lease operations CO annual emissions in the GOM Region

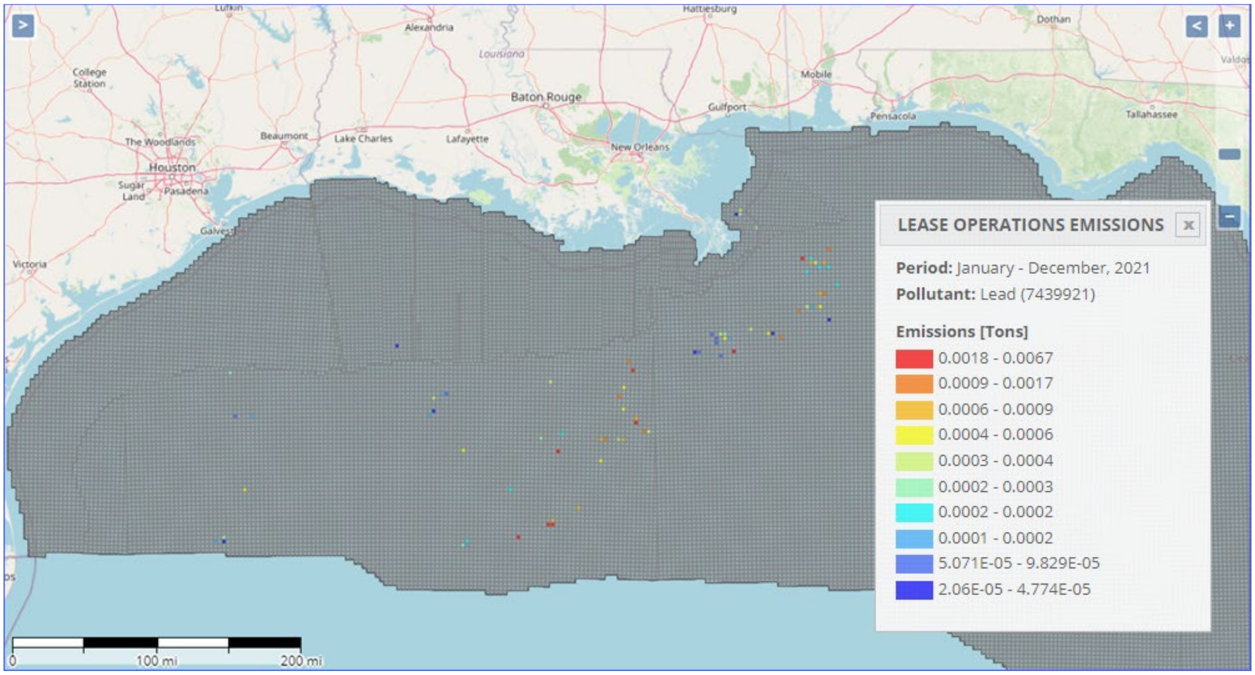

Figure C - 8: 2021 final lease operations Pb annual emissions in the GOM Region

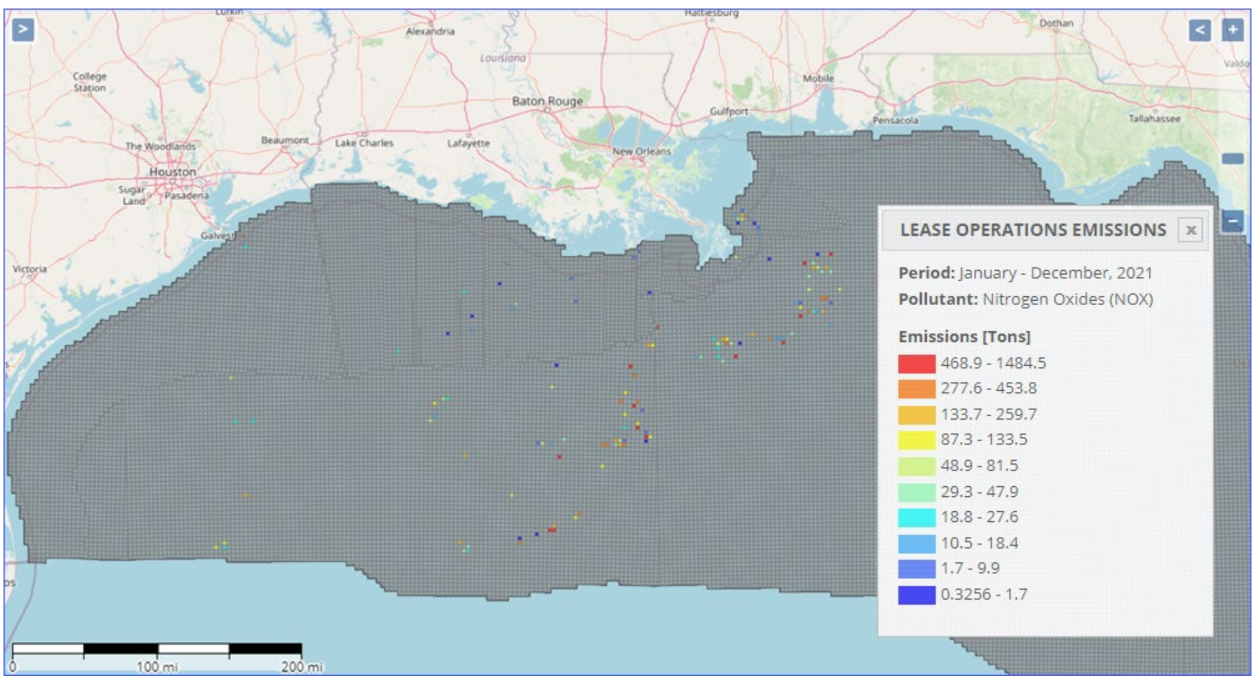

Figure C - 9: 2021 final lease operations NOx annual emissions in the GOM Region

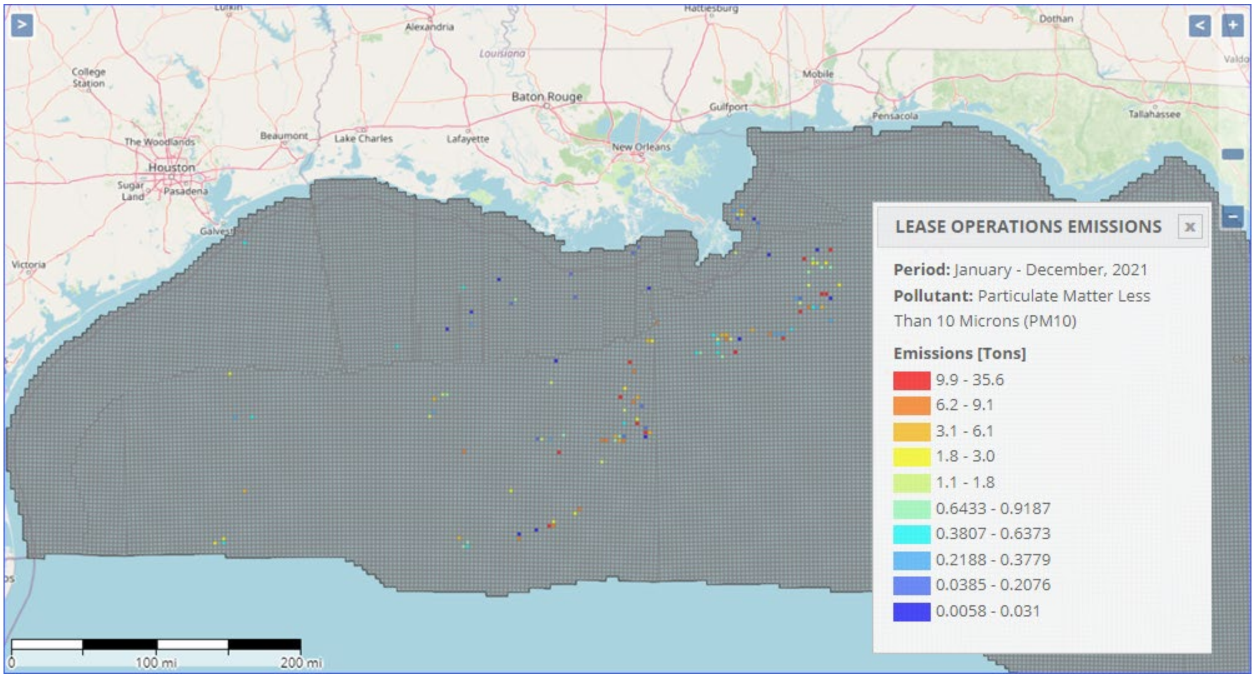

Figure C - 10: 2021 final lease operations PM_{10} annual emissions in the GOM Region

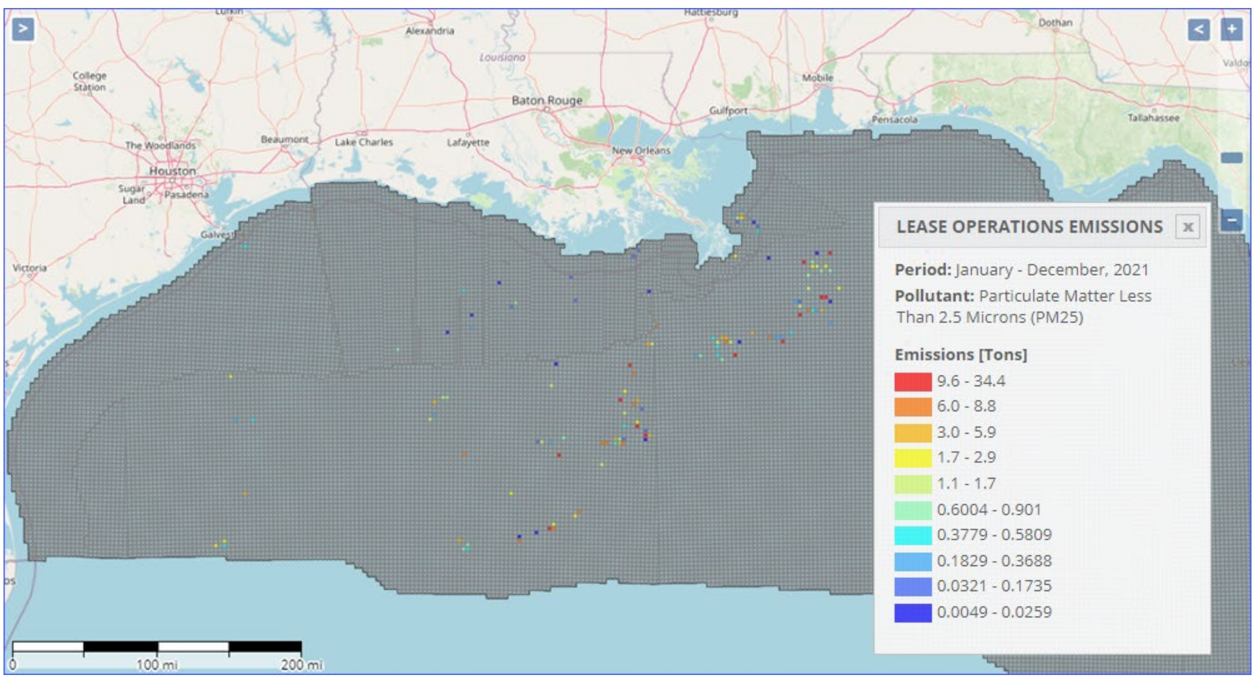

Figure C - 11: 2021 final lease operations $PM_{2.5}$ annual emissions in the GOM Region

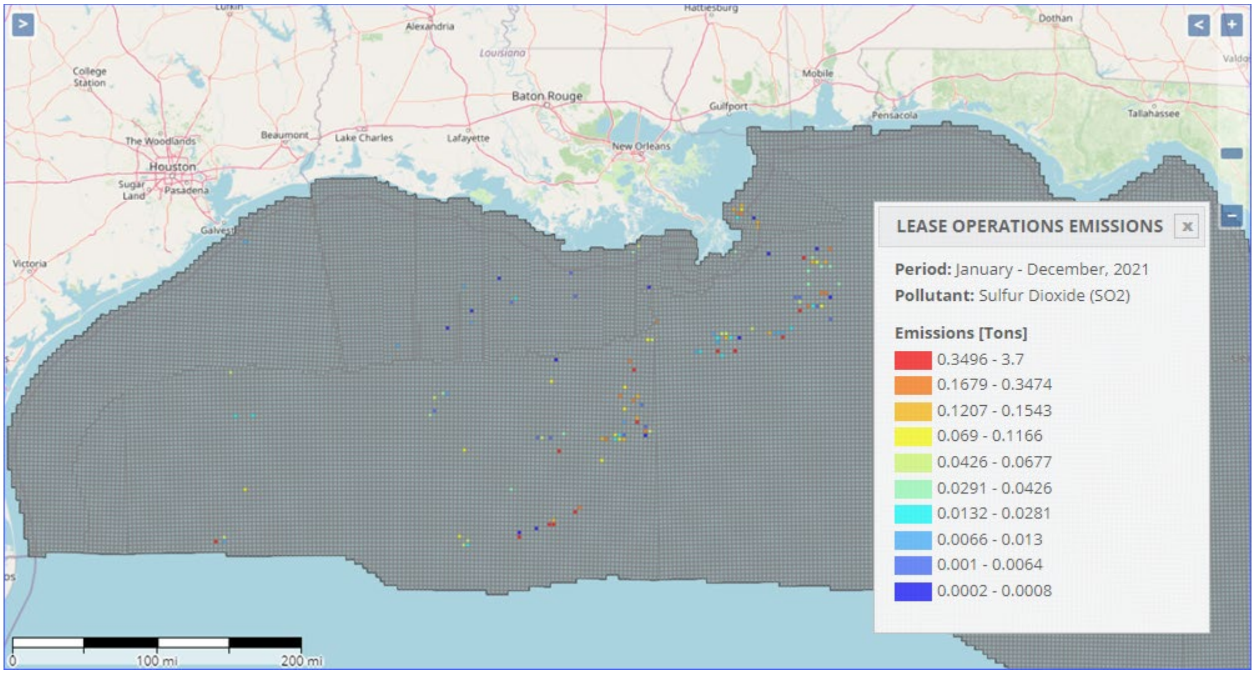

Figure C - 12: 2021 final lease operations SO_2 annual emissions in the GOM Region

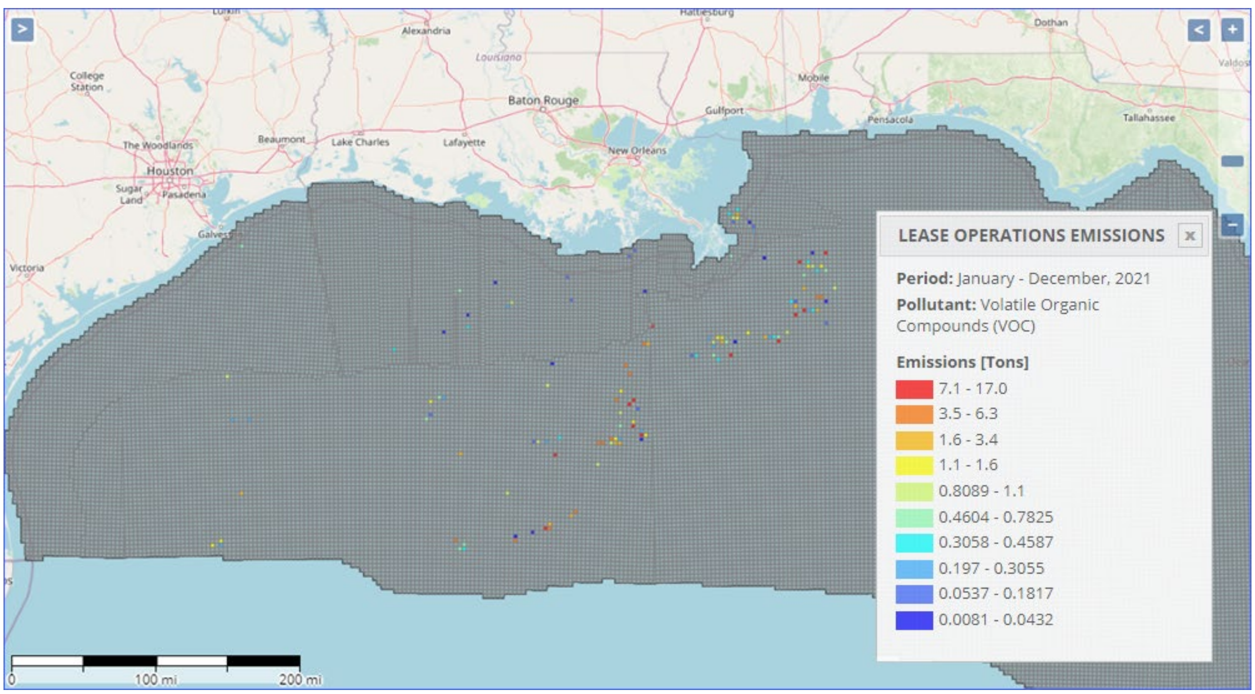

Figure C - 13: 2021 final lease operations VOC annual emissions in the GOM Region

Appendix D – Emission Factor Review

The emission review process for OCS AQS involved meticulously comparing the EFs used in the OCS AQS software with the AP-42 document (USEPA 1995) and other references. Any discrepancies or inaccuracies were carefully documented in the review notes column in the below tables. The Team's goal was to ensure that OCS AQS was using accurate and up-to-date EFs, which would, in turn, help to ensure that the estimated emissions were as precise as possible.

In addition, where available, the EF ratings are included as it is important to consider when determining the basis of the EF values and any uncertainty involved in their calculation. AP-42 EFs are given a general rating factor from A through E, with A being the best and E being the worst (USEPA 1995). The rating factor provides an indication of the reliability of the EF value. The rating is subjective and assigned based on the estimated reliability of the tests used to develop the factor and on both the amount of data available and the representative characteristics of the studies. The assigned EF rating is largely a reflection of the professional judgment of AP-42 authors and reviewers concerning the reliability of any estimates derived with these factors.

In general, EFs based on multiple observations, or on more widely accepted test procedures, are assigned higher rankings. Conversely, a factor based on a single observation of questionable quality, or one extrapolated from another factor for a similar process, would generally be rated much lower. Because EFs are based on source tests, modeling, mass balance, or other information, factor ratings can vary greatly. Some factors have been through more rigorous quality assurance than others.

Please note that the AP-42 EFs and ratings are primarily based on onshore equipment data. As a result, they may not accurately represent offshore equipment, resulting in an unknown level of uncertainty. AP-42 EF quality ratings are described as follows:

A — Excellent	Factor is developed from A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.
B — Above average	Factor is developed from A- or B-rated test data from a "reasonable number" of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with an A rating, the source category population is sufficiently specific to minimize variability.
C — Average	Factor is developed from A-, B-, and/or C-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
D — Below average	Factor is developed from A-, B- and/or C-rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.
E — Poor	Factor is developed from C- and D-rated test data, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry.

D.1 Boilers, Heaters, and Burners

Table D - 1: Units powered by diesel (BOI-M01R Ver.4)

Pollutant	EF Value	Units	EF Rating	Review Notes
Ammonia (NH_3)	0.8	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Arsenic (7440382)	0.0013	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0002	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Beryllium (7440417)	2.78E-05	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	0.0004	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	22,300	lb/1,000 gal	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	5	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium (VI) (18540299)	0.0002	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium III (16065831)	0.0006	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Ethyl Benzene (100414)	6.36E-05	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.033	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Lead (7439921)	0.0012	lb/1000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015))
Mercury (7439976)	0.0001	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	0.052	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	24	lb/1,000 gal	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrous Oxide (N_2O)	0.26	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	1	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.25	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	142 x *S*	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Toluene (108883)	0.0062	lb/1,000 gal	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.2	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.0001	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 2: Units powered by diesel (BOI-M02R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Ammonia (NH_3)	0.8	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Arsenic (7440382)	0.0013	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0002	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Beryllium (7440417)	2.78E-05	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	0.0004	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	24,400	lb/1,000 gal	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	5	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium (VI) (18540299)	0.0002	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium III (16065831)	0.0006	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Ethyl Benzene (100414)	6.36E-05	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.033	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Lead (7439921)	0.0015	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Mercury (7439976)	0.0001	lb/1,000 gal	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	1	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NOX)	47	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrous Oxide (N_2O)	0.53	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Sulfur Dioxide (SO_2)	157 x *S*	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0062	lb/1,000 gal	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.28	lb/1,000 gal	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.0001	lb/1,000 gal	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 3: Units powered by natural gas, process gas, or waste gas (BOI-M03R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Ammonia (NH_3)	3.2	lb/MMscf	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Arsenic (7440382)	0.0002	lb/MMscf	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0021	lb/MMscf	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Beryllium (7440417)	0.000012	lb/MMscf	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	0.0011	lb/MMscf	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	120,000	lb/MMscf	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	84	lb/MMscf	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium (VI) (18540299)	0.000056	lb/MMscf	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium III (16065831)	0.0013	lb/MMscf	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.075	lb/MMscf	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Hexane (110543)	1.8	lb/MMscf	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Lead (7439921)	0.0005	lb/MMscf	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Mercury (7439976)	0.0003	lb/MMscf	D	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	2.3	lb/MMscf	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	190	lb/MMscf	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Nitrous Oxide (N_2O)	2.2	lb/MMscf	E	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	1.9	lb/MMscf	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	1.9	lb/MMscf	B	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.6	lb/MMscf	A	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0034	lb/MMscf	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	5.5	lb/MMscf	C	Reference verified: AP-42, Sections 1.3 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

D.2 Diesel and Gasoline Engines

Table D - 4: Gasoline engines (DIE-M01R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Carbon Dioxide (CO_2)	154	lb/MMBtu	B	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.99	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	1.63	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.1	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.1	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.084	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	3.03	lb/MMBtu		Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 5: Diesel engines with max HP < 600 (DIE-M02R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	0.0008	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0009	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	164	lb/MMBtu	B	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Carbon Monoxide (CO)	0.95	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.0012	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	4.41	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	0.0002	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.31	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.31	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.29	lb/MMBtu	D	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0004	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.36	lb/MMBtu		Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.0003	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 6: Diesel engines with max HP ≥ 600 (DIE-M03R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	2.52E-05	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0008	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	165	lb/MMBtu	B	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.85	lb/MMBtu	C	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	7.89E-05	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	0.008	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	3.2	lb/MMBtu	B	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	0.0002	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0573	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.0479	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	1.01 x *S*	lb/MMBtu	B	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0003	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.08	lb/MMBtu		Discrepancy found as compared with AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.0002	lb/MMBtu	E	Reference verified: AP-42, Sections 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

D.3 Drilling Equipment

Table D - 7: Units powered by gasoline (DRI-M01R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Carbon Dioxide (CO_2)	154	lb/MMBtu	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.99	lb/MMBtu	D	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	1.63	lb/MMBtu	D	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.1	lb/MMBtu	D	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.1	lb/MMBtu	D	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.084	lb/MMBtu	D	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	3.03	lb/MMBtu		Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 8: Units powered by diesel (DRI-M02R Ver.4)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	2.52E-05	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0008	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	165	lb/MMBtu	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.85	lb/MMBtu	C	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	7.89E-05	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	0.0081	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	3.2	lb/MMBtu	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	0.0002	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0573	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.056	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	1.01 x S	lb/MMBtu	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0003	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.0819	lb/MMBtu		Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.0002	lb/MMBtu	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 9: Units powered by natural gas (DRI-M03R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	5.86	lb/MMscf	C	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	1.06	lb/MMscf	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	112,200	lb/MMscf	A	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	2,127.3	lb/MMscf	C	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Ethyl Benzene (100414)	0.03	lb/MMscf	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	38.54	lb/MMscf	A	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	755	lb/MMscf	C	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	2,467.5	lb/MMscf	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	0.09	lb/MMscf	D	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	4.9	lb/MMscf	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	4.9	lb/MMscf	E	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.6	lb/MMscf	A	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.51	lb/MMscf	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	75.3	lb/MMscf	C	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.2	lb/MMscf	B	Reference verified: AP-42, Sections 3.2, 3.3 and 3.4 (USEPA 1995) and WebFIRE (USEPA 2015)

D.4 Combustion Flares

Table D - 10: Combustion flares (FLA-M01 Ver.3)

Pollutant	EF Value	Units	Review Notes
2,2,4-Trimethylpentane (540841)	0.0021	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Acetaldehyde (75070)	0.0552	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	Review Notes
Benzene (71432)	0.0016	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	117.65	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.31	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Ethyl Benzene (100414)	0.00009	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.083	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Hexane (110543)	0.0075	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_x)	0.068	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrous Oxide (N_2O)	0.002	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0014	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	-	lb/lb-mol	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.0004	lb/MMBtu	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 11: Flare pilots (FLA-M02 Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Ammonia (NH_3)	3.2	lb/MMscf	C	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Arsenic (7440382)	0.0002	lb/MMscf	E	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.0021	lb/MMscf	B	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Beryllium (7440417)	0.000012	lb/MMscf	E	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	0.0011	lb/MMscf	D	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Dioxide (CO_2)	120,000	lb/MMscf	A	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	84	lb/MMscf	B	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium (VI) (18540299)	0.000056	lb/MMscf	D	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Chromium III (16065831)	0.0013	lb/MMscf	D	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.075	lb/MMscf	B	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Hexane (110543)	1.8	lb/MMscf	E	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Lead (Pb)	0.0005	lb/MMscf	D	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Mercury (7439976)	0.0003	lb/MMscf	D	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	2.3	lb/MMscf	B	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	100	lb/MMscf	D	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrous Oxide (N_2O)	2.2	lb/MMscf	E	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	1.9	lb/MMscf	B	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	1.9	lb/MMscf	B	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.6	lb/MMscf	A	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0034	lb/MMscf	C	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	5.5	lb/MMscf	C	Reference verified: AP-42, Sections 13.5 and 1.4 (USEPA 1995) and WebFIRE (USEPA 2015)

D.5 Fugitive Sources

Table D - 12: Total hydrocarbon Efs (lb/component-day) by component, for each process stream

Component	Gas (FUG-M01 Ver.2)	Liquid Natural Gas (FUG-M02 Ver.2)	Heavy Oil (<20 API Gravity) (FUG-M03 Ver.2)	Light Oil (≥20 API Gravity) (FUG-M04 Ver.2)	Water and Oil (FUG-M05 Ver.2)	Water, Oil, and Gas (FUG-M06 Ver.2)
Connector	0.011	0.011	4E-04	0.011	5.8E-03	0.011
Flange	0.021	5.8E-03	2.1E-05	5.8E-03	1.5E-04	0.021
Line	0.11	0.074	0.074	0.074	0.013	0.11
Other†	0.47	0.4	1.7E-03	0.4	0.74	0.74
Pump Seals	0.13	0.69	0.69	0.69	1.3E-03	0.13
Valve	0.24	0.13	4.4E-04	0.13	5.2E-03	0.24

† Other Includes compressor seals, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, and vents.

D.6 NGE

Table D - 13: Natural gas engines, 2-stroke, lean burn (NGE-M01R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
2,2,4-Trimethylpentane (540841)	0.0008	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Acetaldehyde (75070)	0.0078	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Benzene (71432)	0.0019	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Carbon Dioxide (CO_2)	110	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Carbon Monoxide (CO)	0.353	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Ethyl Benzene (100414)	0.0001	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Formaldehyde (50000)	0.0552	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Hexane (110543)	0.0004	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Methane (CH_4)	1.45	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Nitrogen Oxides (NO_X)	1.94	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
PAH, total	0.0001	lb/MMBtu	D	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0384	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.0384	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Sulfur Dioxide (SO_2)	0.0006	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Toluene (108883)	0.001	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Volatile Organic Compounds (VOC)	0.12	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Xylenes (Mixed Isomers) (1330207)	0.0003	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)

Table D - 14: Natural gas engines, 4-stroke, lean burn (NGE-M02R Ver.4)

Pollutant	EF Value	Units	EF Rating	Review Notes
2,2,4-Trimethylpentane (540841)	0.0003	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Acetaldehyde (75070)	0.0084	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Benzene (71432)	0.0004	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Carbon Dioxide (CO_2)	110	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Carbon Monoxide (CO)	0.557	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Ethyl Benzene (100414)	3.97E-05	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Formaldehyde (50000)	0.0528	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Hexane (110543)	0.0011	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Methane (CH_4)	1.25	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Nitrogen Oxides (NO_X)	0.847	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
PAH, total	2.69E-05	lb/MMBtu	D	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Particulate Matter Less Than 10 Microns (PM_{10})	7.71E-05	lb/MMBtu	D	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	7.71E-05	lb/MMBtu	D	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Sulfur Dioxide (SO_2)	0.0006	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Toluene (108883)	0.0004	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Volatile Organic Compounds (VOC)	0.118	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Xylenes (Mixed Isomers) (1330207)	0.0002	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)

Table D - 15: Natural gas engines, 4-stroke, rich burn (NGE-M03R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	0.0028	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)

Pollutant	EF Value	Units	EF Rating	Review Notes
Benzene (71432)	0.0016	lb/MMBtu	B	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Carbon Dioxide (CO_2)	110	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Carbon Monoxide (CO)	3.51	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Ethyl Benzene (100414)	2.48E-05	lb/MMBtu	E	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Formaldehyde (50000)	0.0205	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Methane (CH_4)	0.23	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Nitrogen Oxides (NO_X)	2.27	lb/MMBtu	C	Reference verified: AP-42, Section 3.2 (USEPA 1995)
PAH, total	0.0001	lb/MMBtu	D	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0095	lb/MMBtu	E	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.0095	lb/MMBtu	E	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Sulfur Dioxide (SO_2)	0.0006	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Toluene (108883)	0.0006	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)
Volatile Organic Compounds (VOC)	0.03	lb/MMBtu	C	Discrepancy found as compared with: AP-42, Section 3.2 (USEPA 1995)
Xylenes (Mixed Isomers) (1330207)	0.0002	lb/MMBtu	A	Reference verified: AP-42, Section 3.2 (USEPA 1995)

Table D - 16: Natural gas engines, clean burn (NGE-M04R Ver.3)

Pollutant	EF Value	Units	Review Notes
2,2,4-Trimethylpentane (540841)	0.0001	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Acetaldehyde (75070)	0.0035	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Benzene (71432)	0.0006	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Carbon Dioxide (CO_2)	110	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Carbon Monoxide (CO)	0.88	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)

Pollutant	EF Value	Units	Review Notes
Ethyl Benzene (100414)	4.19E-05	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Formaldehyde (50000)	0.0495	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Hexane (110543)	0.0006	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Methane (CH_4)	1.25	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Nitrogen Oxides (NO_X)	0.59	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Particulate Matter Less Than 10 Microns (PM_{10})	7.71E-05	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	7.71E-05	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Sulfur Dioxide (SO_2)	0.0006	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Toluene (108883)	0.0005	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Volatile Organic Compounds (VOC)	0.12	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)
Xylenes (Mixed Isomers) (1330207)	0.0002	lb/MMBtu	Reference verified: Section 4.2.11 Natural Gas Engines - Year 2017 Emissions Inventory Study (Wilson et al. 2019)

D.7 Dual-Fuel Turbines

Table D - 17: Natural gas dual-fuel turbines with known fuel gas sulfur content (NGT-M01R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	0.00004	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.000012	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	6.93E-06	lb/MMBtu	U	Extracted from WebFIRE (USEPA 2015) SCC code is 20200201
Carbon Dioxide (CO_2)	110	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.082	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium (VI) (18540299)	5.32E-07	lb/MMBtu	U	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium III (16065831)	1.28E-05	lb/MMBtu	U	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Ethyl Benzene (100414)	0.000032	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.0007	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Mercury (7439976)	6.63E-06	lb/MMBtu	U	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	0.0086	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	0.32	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrous Oxide (N_2O)	0.003	lb/MMBtu	E	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	2.2E-06	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0019	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.0019	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.94 × S	lb/MMBtu	B	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0001	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.0021	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.000064	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 18: Natural gas dual-fuel turbines with unknown fuel gas sulfur content (NGT-M02R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Acetaldehyde (75070)	0.00004	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.000012	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	6.93E-06	lb/MMBtu	U	Extracted from WebFIRE (USEPA 2015) SCC code is 20200201
Carbon Dioxide (CO_2)	110	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.082	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Chromium (VI) (18540299)	5.32E-07	lb/MMBtu	U	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium III (16065831)	1.28E-05	lb/MMBtu	U	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Ethyl Benzene (100414)	0.000032	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.0007	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Mercury (7439976)	6.63E-06	lb/MMBtu	U	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Methane (CH_4)	0.0086	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	0.32	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrous Oxide (N_2O)	0.003	lb/MMBtu	E	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	2.2E-06	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0019	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.0019	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	0.0035	lb/MMBtu	B	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Toluene (108883)	0.0001	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.0021	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Xylenes (Mixed Isomers) (1330207)	0.000064	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)

Table D - 19: Dual-fuel turbines using diesel fuel (NGT-M03R Ver.3)

Pollutant	EF Value	Units	EF Rating	Review Notes
Arsenic (7440382)	0.000011	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Benzene (71432)	0.000055	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Beryllium (7440417)	3.1E-07	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Cadmium (7440439)	4.8E-06	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)

Pollutant	EF Value	Units	EF Rating	Review Notes
Carbon Dioxide (CO_2)	157	lb/MMBtu	A	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Carbon Monoxide (CO)	0.0033	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium (VI) (18540299)	1.98E-06	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Chromium III (16065831)	9.02E-06	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Formaldehyde (50000)	0.0003	lb/MMBtu	B	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Lead (Pb)	0.000014	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Mercury (7439976)	1.2E-06	lb/MMBtu	D	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Nitrogen Oxides (NO_X)	0.88	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
PAH, total	0.00004	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 10 Microns (PM_{10})	0.0043	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Particulate Matter Less Than 2.5 Microns ($PM_{2.5}$)	0.0043	lb/MMBtu	C	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Sulfur Dioxide (SO_2)	1.01 × S	lb/MMBtu	B	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)
Volatile Organic Compounds (VOC)	0.0004	lb/MMBtu	E	Reference verified: AP-42 Section 3.1 (USEPA 1995) and WebFIRE (USEPA 2015)

Appendix E – Glycol Dehydrators Zero Emissions Details

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10091-1 B	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10135-1 A	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10140-2 CF	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10144-1 C	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10175-1 A	GR-SC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10178-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10212-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10223-1 A	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10225-3 C-PRD	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
10290-1 A	GV-01 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1035-1 A Holstein	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10597-1 B	D-SC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1088-1 A (Matterhorn (SE))	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	No	No	Yes	Yes	Yes	No
113-1 A (Virgo)	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1147-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1224-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	No	No	Yes	Yes	Yes	Yes
1288-1 A - Gunnison	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1323-1 A - Marco Polo	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1665-1 A - Constitution	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1808-1 K	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1812-1 B	GRSCC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1917-1 C	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008-1 A-Perdido	GLY100 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20104-3 L-CMP-VALVE	GV-01 Glycol Dehydrator Unit GLY	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20207-1 CC	GLYUNIT1 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Shut-in/Out of Service (September - December)	No	No	No	No	No	No	No	No	Yes	Yes	Yes	Yes
20226-1 D	GR-SC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20330-2 C-PRD	GD1 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20390-2 BB	NBC1100 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20630-2 A-GEN	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Shut-in/Out of Service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20632-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20687-1 B	GLY-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20706-1 A	MAF-1000 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20717-2 E	GV-01 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
20724-3 A-CMP	GR-SC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Shut-in/Out of Service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20806-1 F	GD1 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20885-4 CMP1	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21098-1 H	GC-01 Glycol Dehydrator Unit GLY	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21108-2 P	GV-01 Glycol Dehydrator Unit GLY	-	No	No	No	No	No	No	No	No	Yes	Yes	Yes	Yes
21273-3 F	GLY-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	No	No	Yes	No	No	No
21284-3 J	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21444-1 C	STILLCOL Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21515-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21566-1 A	GLY-01 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21664-2 E	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21725-1 A	BBC0200 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21786-8 D	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
21830-2 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21831-2 E-COMP	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	No	No	Yes	Yes	No	No
21895-1 A (Gemini)	MAF1020 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21895-1 A (Gemini)	MAF1044 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21903-1 D	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
21988-4 B	GLY-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2201-1 D	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22019-1 B	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22123-1 A	DEHY Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22178-1 A-Cognac	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22355-1 A	GR-SC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22380-1 A	GLYHEYD Glycol Dehydrator Unit GLY	-	No	No	No	No	No	No	No	No	Yes	Yes	Yes	No
22380-1 A	GLYHEYD-2 Glycol Dehydrator Unit GLY	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
22490-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	Yes	No	No	No	No	No
22674-2 A-PROD	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	No	No	Yes	No	No	No
22695-1 G	GV-01 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22771-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
22859-1 A	GV-01 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23005-1 A	GLYCOL Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23167-1 A	STILLCOL Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23173-1 A	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23289-1 C	DEHY Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23454-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23474-2 A - AP	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23494-1 C	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
23497-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned in reporting year (January - October)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
235-1 Marlin TLP	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23529-1 JA	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23813-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23839-1 A	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23839-2 B	GLYSC Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2385-1 B-Olympus	GLY001 Glycol Dehydrator Unit GLY	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23868-1 A	GDU001 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23883-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
23894-2 AP	Dehy Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
240-1 B	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24080-1 A-Auger TLP	GLY100 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
24080-1 A-Auger TLP	GLY500 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24129-1 A (LOBSTER)	GV-01 Glycol Dehydrator Unit GLY	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24130-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24130-1 A	GV-02 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	No	No	No	No	No	No	No	No	No	No	Yes	Yes
24194-1 A	GLYSC Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24199-1 A-Mars TLP	GLY100 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
24229-1 A-Ram Powell	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2503-1 A-Turritella	GLY700 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2532-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2532-1 A	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Ownership transfer	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2570-1 C	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2576-1 A - Lucius	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Facility ID Name	Equipment	Reason	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2644-1 B	GLYV Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Other (January - June)	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No
27062-1 A	MAF-2600 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
28002-1 B	GLYSC Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
420-1 A-Brutus TLP	MAF-610 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
463-1 B	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Decommissioned/Sold/ Removed prior to reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
50010-2 B-AUX	GC-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
70004-1 A-Ursa TLP	GLY100 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
70020-1 A-Morpeth	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Removed in reporting year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
745-1 A	GLY-1 Glycol Dehydrator Unit GLY	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
821-1 A - Nansen	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Out of service	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
876-1 A - Horn Mountain	GV-01 Glycol Dehydrators: Ethylene Glycol GLY Glycol Dehydrator Unit	Amine/Glycol emissions not vented locally	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

U.S. Department of the Interior (DOI)

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Bureau of Ocean Energy Management (BOEM)

BOEM's mission is to manage development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.

BOEM Environmental Studies Program

The mission of the Environmental Studies Program is to provide the information needed to predict, assess, and manage impacts from offshore energy and marine mineral exploration, development, and production activities on human, marine, and coastal environments. The proposal, selection, research, review, collaboration, production, and dissemination of each of BOEM's Environmental Studies follows the DOI Code of Scientific and Scholarly Conduct, in support of a culture of scientific and professional integrity, as set out in the DOI Departmental Manual (305 DM 3).