Criteria Air Pollutant and Greenhouse Gas Emission Factors Compiled by Eastern Research Group for Incorporation in GREET

Systems Assessment Group

Energy Systems Division

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We adopted all the criteria air pollutant (CAP, including VOC, CO, NO_x, PM_{10}, $PM_{2.5}$, and SO_x) and greenhouse gas (GHG, including CH_4 and N_2O) emission factors that were compiled and documented in the following technical memorandum by Eastern Research Group (ERG) with some exceptions and clarifications that we outline herein.

1. The black carbon emissions factors estimated by ERG were not adopted for incorporation in GREET1_2014. Instead, we have estimated and adopted black carbon emission factors that are detailed in (Cai and Wang, 2014a, 2014b).
2. For utility boilers and other combustion technologies adopted by the power sector, including coal-fired integrated gasification combined cycle plants, natural gas simple cycle turbines, natural gas combined cycle turbines, and oil-fired turbines, the ERG CAP and GHG emission factors were based on what we estimated based on the 2007 performance data for electric generating units (Cai et al., 2012). In GREET1_2014, the updated CAP and GHG emission factors based on the 2010 performance data for electric generating units (Cai et al., 2013) were adopted.
3. For coal-fired industrial boilers, the ERG CAP and GHG emission factors for coal-fired boilers with a heat input of 100 to 250 mmBtu/hr are adopted for coal-fired industrial boilers in GREET1_2014. In particular, the ERG PM_{10} and $PM_{2.5}$ emission factors for bituminous and subbituminous coal-fired industrial boilers are aggregated on a basis of 50% versus 40% relative ratio (Cai et al., 2012) to represent the integrated PM_{10} and $PM_{2.5}$ emission factors for coal-fired industrial boilers, assuming that the boilers fed with other types of coal, e.g. lignite, synthetic coal, and waste coal that accounted for about 10% of the coal mix have the same PM_{10} and $PM_{2.5}$ emission factors as the integrated ones.
4. ERG inadvertently switched the N_2O emission factors for uncontrolled and low-nitrogen combustion natural gas-fired boilers with a heat input of no less than 100 mmBtu/hr. We therefore corrected the N_2O emission factor to 0.75 g/mmBtu according to the AP-42 compilation of air pollutant emission factors (U.S. Environmental Protection Agency, 1995).
5. The ERG CAP and GHG emission factors for residual oil-fired boilers with a heat input of 100 to 250 mmBtu/hr and less than 10 mmBtu/hr, respectively, were adopted for residual oil-fired industrial boilers and commercial boilers, respectively, in GREET1_2014.

6. The ERG CAP and GHG emission factors, except for SO_x, for diesel-fired stationary reciprocating engines were adopted for residual oil-fired stationary reciprocating engines in GREET1_2014.
7. The PM_{10} and $PM_{2.5}$ emission factors ERG reported for diesel-fired industrial boilers with a heat input of 100 to 250 mmBtu/hr were inadvertently based on those for commercial boilers. We corrected these emission factors to equal those suggested by the AP-42 compilation of air pollutant emission factors (U.S. Environmental Protection Agency, 1995).
8. The ERG CAP and GHG emission factors for petroleum coke-fired industrial boilers were based on what we estimated for petroleum coke-fired utility boilers using EPA's 2007 performance data for electric generating units (Cai et al., 2012). In GREET1_2014, the updated CAP and GHG emission factors for petroleum coke-fired utility boilers based on the 2010 performance data for electric generating units (Cai et al., 2013) were adopted for petroleum coke-fired industrial boilers in GREET1_2014.
9. For biogas-fired stationary reciprocating engines, the emission factor ERG developed for CH_4 emissions was based on the 2006 IPCC guidelines (Table 2.3) (Intergovernmental Panel on Climate Change, 2006). Emission factors in Table 2.3 are specific only to fuel type and not combustion technology. Rather than use this non-specific emission factor, GREET1_2014 uses the emission factors Mintz et al. (2010) developed for landfill gas-fired engines.

Reference

Cai, H., Wang, M., Elgowainy, A., and Han, J. (2012). Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units. https://greet.es.anl.gov/publication-updated-elec-emissions.

Cai, H., Wang, M., Elgowainy, A., and Han, J. (2013). Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010. https://greet.es.anl.gov/publication-electricity-13.

Cai, H., and Wang, M. (2014a). Estimation of Emission Factors of Particulate Black Carbon and Organic Carbon from Stationary, Modile, and Non-point Sources in the United States for Incorporation into GREET. https://greet.es.anl.gov/publication-black-carbon-greet.

Cai, H., and Wang, M.Q. (2014b). Consideration of Black Carbon and Primary Organic Carbon Emissions in Life-Cycle Analysis of Greenhouse Gas Emissions of Vehicle Systems and Fuels. Environ. Sci. Technol. DOI: 10.1021/es503852u.

Intergovernmental Panel on Climate Change (2006). 2006 IPCC Guidelines for National GHG Inventories, Volume II, Chapter 2 - Stationary Combustion. http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf.

Mintz, M., Han, J., Wang, M., and Saricks, C. (2010). Well-to-Wheels Analysis of Landfill Gas-Based Pathways and Their Addition to the GREET Model. http://www.transportation.anl.gov/pdfs/TA/632.PDF.

U.S. Environmental Protection Agency (1995). AP-42 Compilation of Air Pollutant Emission Factors, Volume 1: Stationary and Point Emission Sources. http://www.epa.gov/ttnchie1/ap42.

ERG Technical Memorandum on Emission Factors

1. Emission Factors for Boilers

1.1 Summary

The primary goal of this project is to develop emission factors that are compatible with the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. This memorandum is a deliverable under ERG contract 3F-31281 with Argonne National Laboratory. Specifically, the stationary source factors provided in this memorandum meet the requirements of Task 10.

ERG developed emission factors for boilers (utility, industrial, commercial, and institutional sectors). This memorandum describes the sources of information and the approach used to develop these factors.

To determine baseline emission factors for 2013, ERG reviewed EPA's AP-42 compilation of emission factors, default greenhouse gas emission factors provided for the Greenhouse Gas Reporting Program (GHGRP), state initiatives to promote low sulfur fuel oil usage, and regulatory support documents for each of the rules noted in Section 2.0, below. In addition, for EGU boilers, ERG reviewed a 2012 Emission Factor Review document from Argonne. Where applicable, emission factors were also derived from emissions data in the Boiler MACT database. In determining 2013 baseline and projected emission factors for 2020 and 2030, regulatory emission limits and boiler population data were incorporated where practicable to calculate weighted average emission factors.

The accompanying Appendix A (GREET Boilers AppA- Gas and Liquid.xlsx) summarizes the emission factors, raw data, and references for boilers burning gas or liquid fuels (natural gas, liquefied petroleum gas (LPG), distillate liquid, and residual oil). Appendix B (GREET Boilers AppA- Solid Fuels.xlsx) summarizes this information for boilers burning solid fuels (bituminous and sub-bituminous coal, petroleum coke, wet biomass, and bagasse). Due to the large number of references used to develop these emission factors, they are noted within the appendices rather than within this memorandum.

1.2 Regulations Affecting Boilers

Several different rules regulate emissions of criteria pollutants and hazardous air pollutants (HAP) in boilers. The applicability and specific emission limit in each regulation is generally a function of boiler size (million British thermal units per hour of heat input (mmBtu/hr) or megawatts (MW) of electricity output), boiler fuel type, boiler combustor design, function of the boiler (i.e., electric generating unit (EGU) or non-EGU), as well as what type of facility at which the boiler is located (i.e., an area or major source of HAP. A major source of HAP is defined as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit (considering controls) 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP.

The following regulations were considered in the development of baseline and projected emission factors.

Table 2-1 Regulations Affecting Emissions from Boilers

Rule	Affected Boiler Population	Pollutants With Numeric Emission Limits*
New Source Performance Standards for Electric Utility Steam Generating Units constructed after September 18, 1978 (40 CFR Part 60, Subpart Da)	New EGU boilers (>250 mmBtu/hr)	PM (filterable-PM-fil), SO_2, NOx
New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units constructed after June 19, 1984 (40 CFR Part 60, Subpart Db)	New Industrial-Commercial-Institutional (ICI) boilers (>100-250 mmBtu/hr EGU boilers; non-EGUs >250; and Biomass EGUs >100 mmBtu/hr)	PM-fil, SO_2, NOx
New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units constructed after June 9, 1989 (40 CFR Part 60, Subpart Dc)	New ICI boilers (10 to 100 mmBtu/hr)	PM-fil, SO_2
National Emission Standards for Major Sources: Industrial/Commercial/Institutional Boilers and Process Heaters (40 CFR Part 63, Subpart DDDDD)	New and existing ICI boilers at area sources of HAP and biomass EGU boilers (all sizes)	PM-fil, Hg, HCl, CO, non-Hg metallic HAP
National Emission Standards for Area Sources: Industrial/Commercial/Institutional Boilers (40 CFR Part 63, Subpart JJJJJJ)	New and existing boilers at area sources of HAP and biomass EGU boilers (all sizes)	PM-fil, Hg, CO
National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63, Subpart UUUUU)	New and Existing EGU boilers (>250 mmBtu/hr)	PM-fil, Hg, non-Hg metallic HAP, SO2, HCl

*Emission limits or fuel standards are established for these pollutants. However, the control devices installed to comply with these regulations have the co-benefit of reducing other pollutants (e.g., lower sulfur fuels reduce emissions of PM2.5).

Table 2-1 includes only regulations that have been promulgated. Note that there is a planned rule affecting new EGU boilers and integrated gasification combined cycle (IGCC) turbines under development “Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units” (See Rule Docket EPA-HQ-OAR-2006-0790). This rule was not included in the emission factor analysis because it is not finalized.

Regulatory limits applied to emission factor calculations are presented in the “NSPS Limits” tabs of Appendices A and B as well as the individual fuel- and design-specific tabs in which the calculations are made, where applicable.

In addition to these specific regulations, for fuel oil-fired boilers ERG considered state regulations in several Northeastern states (NY, MA, ME, VT, NJ) that have finalized requirements for the use of low sulfur and ultra low sulfur fuel oil. These factors were considered in developing the emission factors because the majority of fuel oil consumption in boilers occurs in the Northeastern states.

2.3 Emission Factors

Final baseline and future emission factors for each fuel type and boiler size category are presented in the “Summary” tabs of Appendix A (liquid and gas fuels) and Appendix B (solid fuels). Detailed calculations, assumptions, and references can be found in the corresponding individual calculation tabs. The general methodology for developing these factors is described in sections 3.1 and 3.2 below.

2.3.1 Baseline Year (2013)

Although the emission limits for some of the rules in Table 2-1 are unique to certain combustor designs and AP-42 presents emission factors for boilers for numerous combustor designs, this analysis was limited to most prominent combustor designs for each fuel type in order to simplify the analysis and focus on the boiler applications for which a majority of each fuel type is expected to be combusted.

In many cases, available emission factor data were broken down by control type and/or combustor design. For instance, large non-EGU natural gas fired units were grouped based on the presence of low NO_x control (LNC) and whether they were tangentially fired or wall-fired. Similarly, non-EGU distillate oil, residual oil, and coal fired boilers >10 mmBtu/hr were also separated based on LNC. Among solid fuel boilers, the type of PM control and the presence of an acid gas control also affected emission factors. Available factors for coal-fired boilers were also broken down by combustion design (spreader-stoker, pulverized coal dry bottom, and fluidized bed). In all of these cases, available population and/or control device distribution data were used to weight the average fuel-specific emission factors provided for each pollutant.

Most emission factor data were provided in units of pound (lb) of emissions per volume of fuel for gas or liquid fuels and in units of lb of emissions per ton of fuel for solid fuels. GREET1_2013 lower heating values (LHVs) were used to convert these emission factors to a lb/mmBtu basis. For EGU boilers, emission factor data were often provided as output-based standards. The standards for the NSPS (40 CFR Part 60 Subpart Da) provided both net and gross factors and the net factors (lb/MWh net) were used in this analysis, consistent with the basis of the factors in the base year data from the Argonne report. The NESHAP (40 CFR 63 Subpart UUUUU) provided the standards in a gross output basis only. These gross factors were converted to a net basis using a factor of 0.92 gross to net based on the ratio of gross and net basis emission limits in the NSPS rule.

Some of the emission factor data were provided in terms of concentration of pollutant in the exhaust gas. These data were converted to a lb/mmBtu basis using F-

Factors to relate the Btu content of the fuel to the exhaust gas. Table 2-2 shows the F-Factors used for each fuel type. These F-Factors are on a higher heating value (HHV) basis, so GREET1_2013 LHV and HHV values were used to convert the factors to a LHV basis.

With the exception of the biomass factors, all factors were standardized to units of lb/mmBtu (LHV) basis. Biomass factors were standardized to a lb/mmBtu (HHV) basis and the average moisture content of each fuel type was also provided in each biomass calculation tab of Appendix B, since the moisture content of biomass can have a large impact on the resulting emission factors.

Table 2-2 F_d Factor for Fuel Types from EPA Method 19.

Fuel Category	F_d-Factor (dscf of exhaust/mmBtu)
Bagasse	9335[a]
Coal (Bituminous)	9780
Natural Gas	8710
Heavy Liquid	9190
Light Liquid	9190
Wet Biomass	9600

a. The F-factor for Bagasse was provided based on data from the Florida Sugar Cane League and not EPA Method 19.

For coal units, when possible, emission factors were separated by coal rank. This was the case for all pollutants for coal EGUs. For ICI boilers, separate factors were only available for CO_2, black carbon, and PM. Factors were not distinguished between bituminous and sub-bituminous for the remaining pollutants at ICI boilers.

2.3.2 Emission Factors – Projected Years (2020 and 2030)

The EIA Annual Energy Outlook 2011 was used to project which fuel types were expected in the electric power, industrial, and commercial sectors. These projections were then incorporated into the relative distribution of new and existing units in each category in order to come up with a single weighted emission factor for each pollutant/boiler combination based on the limits set forth in each applicable regulation. In cases where a numerical emission limit was less stringent than the baseline emission factor, the baseline was used instead.

It is worth mentioning that the NESHAP regulations for both EGU and ICI boilers provide a limit for total filterable PM as opposed to size-specific PM limits or limits on total filterable and condensable PM emissions. AP-42 provides cumulative particle size distributions for various combinations of control device, fuel type, and boiler combustor design. We applied these distributions to the total filterable PM emission limits in order to estimate the projected emission factors for filterable PM less than 10 and 2.5 micrometers, respectively. It is also noted that the NESHAP rules provide for an alternative non-Hg metallic HAP emission limit instead of the filterable PM emission limit. Some units may opt to comply with these limits instead of installing PM controls if the metallic content of their fuels meet the limits set forth in each applicable regulation without requiring additional controls to be installed.

Several regulations limit fuel oil sulfur content in the Northeast. While the resulting effect on SO_2 emission factors can be estimated, we note that the lower sulfur content will have a co-benefit on reducing particulate emissions, especially fine particulate. However these reductions were not quantified in this analysis, given the lack of available data.

For bagasse units, it was noted that CO_2 emissions would increase when using a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used. However, we do not have data to quantify this increase, so the CO2 emisison factor based on no control has been used for the baseline as well as future projections.

2.4 Data Gaps

Emission factors for crude oil firing in boilers were not available for the pollutants of interest under this task. After reviewing several databases for recent boiler regulations, no boilers firing crude oil were identified and no factors were available in EPA AP-42 documents. If crude oil factors are necessary for the model, it is noted that emissions from crude oil are expected to vary depending on the unique emission profile of each crude oil. In the absence of any other data, the factors developed for residual fuel oil combustion are the best surrogate to use for crude oil.

Emission factors for liquefied petroleum gas (LPG) combustion were not developed for large (>100 mmBtu/hr) industrial or utility boilers. The EIA Annual Energy Outlook does not project any LPG consumption in the electricity sector. Further, EIA shows flat growth in the commercial sector and some growth in the industrial sector, which given the economics of LPG combustion, are likely for smaller boilers or other combustion equipment in these sectors.

Emission factors for switchgrass, miscanthus, corn stover, lignin, and char were not available for the pollutants of interest under this task. Instead, general biomass emission factors were developed for wet biomass (primarily forest residue) and bagasse. Only very limited test data were available these specific types of biomass species and these tests were based test burn trials. The trials were often conducted while co-firing a certain species with other fuel types so it is difficult to isolate the emissions for an individual biomass species.

2.5 Boiler Efficiencies

For ICI boilers not generating electricity, boiler efficiency data for solid and liquid ICI boilers were collected from several sources as part of the recent boiler national emission standards for HAP rulemaking (78 FR 7138, January 31, 2013). No data was collected on natural gas, petroleum coke, crude oil or LPG units. The data collected are summarized in Table 5-1 for reference:

Table 5-1 Efficiency Data by Boiler Type

Boiler Type	Efficiency Data[a]		
	Min Boiler Efficiency (%)	Max Boiler Efficiency (%)	Mean Boiler Efficiency (%)
All Solid Fuels	45.5	84.9	72.3
Bagasse	53.6	64.9	57.8
Biomass - Dutch Oven	53.4	60.5	58.2
Biomass - Fluidized Bed	62.9	67.0	65.0
Biomass - Fuel Cell	45.5	67.2	56.4
Biomass - Suspension Burner	78.4	78.4	78.4
Biomass - Wet/stoker	60.0	81.2	69.5
Biomass - Dry/stoker	*No output data found. Use wet biomass stoker.*		
Coal – FB	68.1	83.6	78.6
Coal – PC	60.9	84.7	77.9
Coal – Stoker	58.7	84.9	75.9
All Liquids	60.9	73.3	67.1
Liquid – Heavy	73.3	73.3	73.3
Liquid – Light	60.9	60.9	60.9

a. The above efficiencies were calculated using this equation:
Boiler Efficiency = (Steam Btu Out – Feedwater Btu In)/Fuel Btu In

For utility boilers, efficiency data for each boiler type was compiled in the 2012 Argonne Emission Factor document, which was used as the baseline efficiency.

2.6 References

Primary references are listed below, but due to the large number of referenced used in the development of these emission factors, this list is not comprehensive. All references used for calculations and supporting information are included in Appendices Boiler-A and Boiler-B.

USDOE/Argonne Laboratory. Argonne Laboratory Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and their Probability Distribution Functions for Electric Generating Units. May 2012. ANL/ESD/12-2

Maine Department of Environmental Protection. Report of the Advisory Committee on Reducing Air Emissions Sources' Reliance on Fuel Oil. January 2012. http://www.maine.gov/tools/whatsnew/attach.php?id=357825&an=1

U.S. Energy Information Administration. Annual Energy Outlook 2011. Appendix A. Table A2: Energy Consumption by Sector and Source. April 2011. http://www.eia.gov/forecasts/archive/aeo11/

U.S. Energy Information Administration. Today in Energy. Sulfur content of heating oil to be reduced in northeastern states. April 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=5890

U.S. EPA Office of Air Quality Planning and Standards, AP-42 Compilation of Air Pollutant Emission Factors, Volume 1: Stationary and Point Emission Sources. January 1995. http://www.epa.gov/ttnchie1/ap42/.

U.S. EPA, Report to Congress on Black Carbon. March 2012. http://epa.gov/blackcarbon/

Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under ICR No. 2286.01 & ICR No. 2286.03 (Version 8). (EPA-HQ-OAR-2002-0058-3830)

2. Emission Factors for Stationary Internal Combustion Engines

2.1 Summary

The primary goal of this project is to develop emission factors compatible with the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. This memorandum is a deliverable under contract 3F-31281 with Argonne National Laboratory. Specifically, stationary internal combustion engine emission factors provided in this memorandum meet the requirements of Task 10.

ERG developed emission factors for 2013 as well as projections of 2020 and 2030. This memorandum details the sources and approach used to develop these factors for three separate fuel types: diesel, gasoline, natural gas, and biogas.

To determine baseline emission factors for 2013, ERG reviewed EPA's AP-42 compilation of emission factors, EPA's WebFIRE Emission Factor online database, default greenhouse gas emission factors provided for the Greenhouse Gas Reporting Program (GHGRP), EPA's 2012 Report to Congress, documents from EPA's Climate Leaders progam, Intergovernmental Panel on Climate Change guidance documents, and regulatory documents associated with the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) (40 CFR 63, subpart ZZZZ, docket EPA-HQ-OAR-2008-0708), the Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (40 CFR 60, Subpart JJJJ, docket EPA-HQ-OAR-2005-0030), and the Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (40 CFR 60, Subpart IIII, docket EPA-HQ-OAR-2010-0295). In determining

2013 baseline and projected emission factors for 2020 and 2030, regulatory emission limits and engine population data were incorporated where practicable to calculate weighted average emission factors.

The accompanying appendices (GREET Stationary EnginesEFs _123113.xlsx) summarize the emission factors, raw data, and references for stationary internal combustion engines burning diesel, gasoline, biogas, and natural gas. Due to the large number of references used to develop these emission factors, they are noted within the appendices rather than within this memorandum.

2.2 Diesel Emission Factors

Large stationary diesel engines are primarily used in oil and gas exploration, but they may also be used in electricity generation applications or smaller applications such as industrial generators, pumps, or material handling equipment.

Baseline Emission Factors

EPA's AP-42 chapters on diesel-fueled engines provide the most complete set of emission factors for the pollutants of interest. Specifically, factors are provided for CO_2, CO, NO_x, SO_x, PM_{10}, $PM_{2.5}$, condensable PM, and VOCs. These factors are broken down into separate factors for large (>600 hp) and small (≤600 hp) CI engines. The AP-42 factors were based on a heating value of 137,030 Btu/gal for diesel, so ERG converted the factors to a lower heating value (LHV) basis, assuming a LHV of 128,450 Btu/gal for diesel. Population data suggest that about 90 percent of stationary CI engines are less than 600 hp, so ERG has used this distribution to weight the available emission factors. For NO_x, factors were provided for both uncontrolled units and for large units using ignition timing retard (ITR) for NO_x control. However, the population of large stationary diesel sources using this control is unknown, and other sources suggest that ITR is no longer the primary method of control. Therefore, ERG has conservatively not incorporated the controlled emission factor into the final baseline NO_x emission factor.

CO, NO_x, SO_x, PM_{10}, and $PM_{2.5}$ factors were further adjusted based on applicable standards in the RICE NESHAP and the NSPS for stationary CI engines. Due to the complex nature of these rules, we have not included a table of limits in this memorandum, but a summary table of the applicable standards can be found in Appendix Engine-A. Where necessary, the standards were converted from units of g/kWh to lb/mmBtu assuming a break-specific fuel consumption of 7000 Btu/hp-hr and a ratio of 1.34 hp to 1 kW. Available unit size distribution and population data were used to estimate the percent of units affected for various size categories, and the resulting distribution was used in conjunction with the corresponding emission limits to determine a weighted factor. We estimated a 5 percent growth/replacement rate, assuming 5 percent of the population would be replaced every ten years. The AP-42 emission factors were weighted by multiplying the factor by the percent of units not subject to the regulations, whereas the remaining population was assumed to be meeting the regulatory emission limit. In the case of CO, the regulatory emission limits for smaller units were greater than the AP-42 emission factor. Therefore, when ERG applied the regulatory emission limits as appropriate for the population distribution, the 2013 baseline emission factor calculated was greater than the CO emission factor presented in AP-42. For SO_x, it was assumed that affected units would burn ultra-low sulfur diesel (15 ppm S), so we calculated SO_x emissions from affected units using this concentration (the unaffected units were assumed to have a fuel sulfur concentration of 500 ppm). An additional step was also taken for PM_{10} and $PM_{2.5}$ because the NSPS does not have specific limits for these only for filterable PM. Ratios were calculated based on AP-42 emission factors for PM of varying particle sizes, and these were applied to the standards to determine corresponding limits for PM_{10} and $PM_{2.5}$.

The 2012 EPA Report to Congress on Black Carbon reports that for stationary diesel sources, black carbon composes 77 percent of emitted $PM_{2.5}$. ERG therefore calculated the black carbon emission factor for CI engines as 77 percent of sum of the emission factors determined for filterable $PM_{2.5}$ and condensable PM.

Emission factors for N_2O and CH_4 are based on default values which were consistently provided in multiple sources (GHGRP, Climate Leaders, IPCC) for stationary combustion sources combusting petroleum-based fuels. These values are based on net calorific values according to IPCC guidance documents, so no additional conversions were necessary to produce LHV-based emission factors for these pollutants.

Future Emission Factors

As noted above, ERG reviewed standards for stationary CI engines and identified emission limits for CO, NO_x, PM, as well as fuel requirements that would affect SO_x emissions. Based on available population data, we assumed a 5 percent annual growth/replacement rate. We developed a matrix of affected population fractions for 2013, 2020, and 2030 and for each size category associated with the standards. The resulting distributions were applied to the baseline emission factors and the emission limits to determine the weighted emission factors for each year.

Due to the NESHAP and NSPS emission limits, the CO, NO_x, SO_x, PM_{10}, $PM_{2.5}$, and black carbon emission factors become progressively lower into the future, as a higher percentage of operating engines become subject to the limits and as the applicable limits become more stringent. For other pollutants, we have applied the 2013 emission factors to 2020 and 2030 as there are currently no standards in place to directly regulate their emissions. The table below presents the emission factors by year. Where applicable, the range of emission factors identified for different sized engines is shown in brackets. Appendix Engine-A contains the specific line-item calculations, assumptions and references used in this analysis.

Diesel-Fueled Stationary RICE Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	175 [175 - 176]	175	175
CH_4	0.0093	0.0093	0.0093
N_2O	0.0013	0.0013	0.0013
Black Carbon	0.092	0.032	0.0032
CO	1.4 [0.06 - 2.68]	1.2	0.99
VOC	0.0045 [0.0039 - 0.0045]	0.0045	0.0045
NO_x	4.6	0.59	0.14
SO_x	0.24 [0.054 - 0.309]	0.0016	0.0016
PM_{10}-filterable	0.11 [0.0038 - 0.331]	0.041	0.0043
$PM_{2.5}$-filterable	0.11 [0.0036 - 0.331]	0.041	0.0041
Condensable PM	0.0082	0.0082	0.0082

2.3 Gasoline Emission Factors

Gasoline is used in spark ignition internal combustion engines rated up to roughly 250 to 300 HP. These engines are primarily mobile and portable engines.

Baseline Emission Factors

EPA's AP-42 chapter on small diesel-fueled engine and gasoline engines provided emission factors for CO_2, SO_x, PM_{10}, and $PM_{2.5}$. This chapter referred only to gasoline engines less than or equal to 250 horsepower. One regulatory support document (EPA-HQ-OAR-2005-0030-0191) implied engines range up to 300 HP; however, we have assume most gasoline-fired stationary combustion engines are less than or equal to 250 and that these values are representative of this range. Available factors were based on a heating value of 130,000 Btu/gal for gasoline, so ERG converted the factors to a lower heating value (LHV) basis, assuming a LHV of 112,194 Btu/gal for gasoline.

Although AP-42's chapter also provided factors for CO, NO_x, a memorandum supporting Spark Ignition Internal Combustion Engines NSPS development (EPA-HQ-OAR-2005-0030-0053) provided more up-to-date emission factors for these pollutants for units greater than 25 HP. Assuming most, if not all, stationary gasoline-fired internal combustion engines are greater than 25 HP, we adopted these emission factors.

The CO factor was further adjusted to incorporate the NSPS for spark ignition engines, under which units are subject to the exhaust emission limits of 40 CFR Parts 1048 and 1054. Units must meet the standards for CO as well as for the combined total hydrocarbons plus NO_x. A summary of applicable limits are provided in the table below.

Stationary Spark Ignition Internal Combustion Engines
(40 CFR 60 JJJJ) Emission Limits for Gasoline-fired Engines

Pollutant	40 CFR 1054 (<40 HP and <1L)	40 CFR 1048 (>25 HP)	Units
CO	610	4.4	g/kWh
HC + NO_x	10 (greater than 255 cc displacement) 8 (less than or equal to 255 cc displacement)	2.7	g/kWh

For comparison against the baseline emission factors, the standard for each pollutant or combination of pollutants was converted from g/kWh to lb/mmBtu assuming a brake-specific fuel consumption of 7,000 Btu/hp-hr and a ratio of 608 g/kWh to 1 lb/hp-hr. For CO, the Part 1054 CO emission limit for small engines was significantly higher than the baseline emission factor. Therefore, the Part 1054 emission limit was not used to calculate the 2013 baseline emission factor for CO. The Part 1048 standards in place for units greater than 25 HP, however, are less than baseline emission factors, and are assumed to affect new stationary gasoline engines since 2008. Based on population data provided in regulatory support documentation, it was assumed that about 5 percent of units would be added or replaced per year, meaning that about 30 percent of all units as of 2013 would be new. Furthermore, available data indicated that about 50 percent of gasoline-fired stationary combustion engines are greater than 50 HP and would certainly be subject to the Part 1048 standard. For simplicity, ERG applied this distribution to the baseline emission factor and the Part 1048 CO emission limit to determine a weighted 2013 emission factor.

Due to the difficulty of disaggregating the NO_x and VOC components of the NSPS emission limits, ERG retained the baseline NO_x and VOC values with no further adjustment.

Emission factors for N_2O and CH_4 are based on default values which were consistently provided in multiple sources (GHGRP, Climate Leaders, IPCC) for stationary combustion sources combusting petroleum-based fuels. These values are based on net calorific values according to IPCC guidance documents, so no additional conversions were necessary to produce LHV-based emission factors for these pollutants.

The 2012 EPA Report to Congress on Black Carbon reports that for stationary gasoline sources, black carbon composes 10 percent of emitted $PM_{2.5}$. ERG therefore calculated the black carbon emission factor for gasoline engines as 10 percent of the sum of emission factors determined for filterable $PM_{2.5}$ and condensable PM. In this case, no emission factor data were identified for condensable PM.

Other sources were reviewed to identify emission factors for VOC because AP-42's chapter provided factors only for total organic compounds (TOC). The factor provided in EPA's WebFIRE Emission Factor database was assumed to be the most accurate of factors identified. The factor, reported in pounds per 1000 gallons, was converted to lb/mmBtu using a lower heating value of 112,194 Btu/gal for gasoline.

For condensable PM, as noted above, no emission factor data were identified.

Future Emission Factors

ERG reviewed standards for stationary, gasoline-fired internal combustion engines and identified emission limits for CO, as well as limits for combined emissions of hydrocarbons and NO_x and non-methane hydrocarbons and NO_x. As discussed above, for comparison against the baseline emission factors, the standards for each pollutant or combination of pollutants was converted from g/kWh to lb/mmBtu assuming a brake-specific fuel consumption of 7,000 Btu/hp-hr and a ratio of 608 g/kWh to 1 lb/hp-hr. The resulting lb/mmBtu-based standards were all greater than the corresponding baseline emission factors accept for the CO emission limit for units greater than 25 HP.

Based on the growth/replacement rate and unit size distribution noted above, we estimate that about 33 percent of units in 2020 and 50 percent of units in 2030 would be subject to the Part 1048 CO limit. As described above, these distributions were applied to the baseline emission factor and the Part 1048 CO limit to determine the weighted emission factor for each year.

Due to the NSPS emission limits, the CO emission factor becomes progressively lower into the future, as a higher percentage of operating engines become subject to the limit. As noted previously, NOx and VOC were kept at the baseline levels because the associated emission limit cannot easily be broken down into separate limits. For other pollutants, we have applied the 2013 emission factors to 2020 and 2030 as there are currently no standards in place to directly regulate their emissions. The table below presents the emission factors by year. Appendix Engine-B contains the specific line-item calculations, assumptions and references used in this analysis.

Gasoline-Fueled Stationary RICE Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	178	178	178
CH_4	0.0066	0.0066	0.0066
N_2O	0.0013	0.0013	0.0013
Black Carbon	0.012	0.012	0.012
CO	3.4 [1.03 - 3.76]	2.9	2.4
VOC	1.3	1.3	1.3
NO_x	0.22	0.22	0.22
SO_x	0.097	0.097	0.097
PM_{10}-filterable	0.12	0.12	0.12

$PM_{2.5}$-filterable	0.12	0.12	0.12
Condensable PM	Not available	Not available	Not available

2.4 Biogas Emission Factors

Biogas primarily comprises methane and carbon dioxide and may contain small amounts of moisture and hydrogen sulfide (H_2S). The composition of biogas depends on the type of biogas; anaerobic digester gas typically has a higher methane content (around 55 to 65 percent) than landfill gas (typically around 40-50 percent). Emission factors for biogas were not disaggregated by biogas type, however, because all factors identified were either identical for both landfill and digester gas or the type of biogas was not specified. ERG assumed a LHV of 475 Btu/scf for biogas.

Baseline Emission Factors

Emission factors for VOC, PM_{10}, and $PM_{2.5}$ were based on data provided in an environmental assessment by the South Coast Air Quality Management District in support of their emission standards for gaseous- and liquid-fueled internal combustion engines. All PM_{10} was assumed to be fine, so the PM_{10} emission factor is also used for $PM_{2.5}$. The assessment appeared to use a lower heating value as their basis, so no further adjustments were made to the baseline factors.

The 2012 EPA Report to Congress on Black Carbon reports that for stationary natural-gas combustion, black carbon composes 40 percent of emitted $PM_{2.5}$. There were no separate factors provided for biogas, therefore ERG calculated the black carbon emission factor for biogas engines as 40 percent of the sum of emission factors determined for filterable $PM_{2.5}$ and condensable PM.

Emission factors for CO_2, CH_4, and N_2O are based on default values found in the 2006 IPCC Guidelines for National GHG Inventories. Factors for these pollutants were also identified in default tables for the EPA GHG Reporting Program and in a report from EPA's Climate Leaders progam; however, the converted values were inconsistent with IPCC values, and the heating values used as the basis for the factors was not clear. IPCC presented factors on a net calorific value (LHV) basis, so ERG has selected these emission factors for CO_2, CH_4, and N_2O.

Emission factors for CO and NO_x were based directly on data provided in AP-42 background documentation for landfill emission factor development. To determine an emission factor for SO_x, ERG first assumed all sulfur in the biogas would be converted to SO_2. The AP-42 background documentation uses a default sulfur content of 33 ppm for landfill gas, which we applied to all biogas for the purpose of this task. An emission factor was calculated using this default sulfur content, the molecular weights of sulfur and SO_2, and an assumed lower heating value of 475 Btu/scf for biogas.

For condensable PM, ERG searched EPA's WebFIRE database of emission factors. Data for internal combustion engines were unavailable, so ERG used landfill gas-fired turbine data as a surrogate emission factor.

Future Emission Factors

Data indicate that biogas-fueled ICE units are performing at levels that meet or exceed the NSPS emission limits for landfill and digester gas units. Therefore the 2013 baseline emission factors have been applied to 2020 and 2030. The table below presents the emission factors by year. Where applicable, the range of emission factors identified for different biogas types is shown in brackets. Appendix Engine-C contains the specific line-item calculations, assumptions and references used in this analysis.

Biogas-Fueled Stationary RICE Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	127	127	127
CH_4	0.0023	0.0023	0.0023
N_2O	0.00023	0.00023	0.00023
Black Carbon	0.0061	0.0061	0.0061
CO	0.50	0.50	0.50
VOC	0.041	0.041	0.041
NO_x	0.70	0.70	0.70
SO_x	0.012	0.012	0.012
PM_{10}-filterable	0.013	0.013	0.013
$PM_{2.5}$-filterable	0.013	0.013	0.013
Condensable PM	0.0023 [0.018 - 0.0028]	0.0023	0.0023

2.5 Natural Gas Emission Factors

The majority of natural gas-fired reciprocating engines are used to provide mechanical shaft power for compressors and pumps at pipeline compressor and storage stations and natural gas processing plants. It is assumed the natural gas used in these engines has an LHV of 983 Btu/scf and a HHV of 1,089 Btu/scf. Emission factors are provided in the table below, and details regarding calculations and assumptions are provided in Appendix Engine-D.

Baseline Emission Factors

EPA's AP-42 chapter on natural gas-fired reciprocating engines provided emission factors for CO_2, CH_4, SO_x, PM_{10}, PM_{25}, and condensable PM. All PM_{10} was assumed to be fine, so the PM_{10} emission factor is also used for $PM_{2.5}$. Factors were adjusted from a HHV to LHV basis.

The 2012 EPA Report to Congress on Black Carbon reports that for stationary natural gas combustion sources, black carbon composes 40 percent of emitted $PM_{2.5}$. ERG therefore calculated the black carbon emission factor for natural gas engines as 40 percent of the sum of emission factors determined for filterable $PM_{2.5}$ and condensable PM.

Emission factors for CO, VOC, and NOx are based on factors presented in the Regulatory Impact Analysis (RIA) for Stationary Spark Ignition Rice NESHAP (EPA-HQ-OAR-2008-0708-1493). ERG converted these values from units lb/bhphr to lb/MMBtu assuming an engine heat rate of 7,064 Btu/bhphr.

Future Emission Factors

For 2020 emission factors, ERG estimated the percentages of engines in use that would be subject to either the Stage 1 SI NSPS (applies to units constructed between 1/1/2008 and 12/31/2009), the Stage 2 SI NSPS (applies to units constructed on or after 1/1/2010) standards, or not subject to either of these (i.e., would still have the baseline emission factors). The table below summarizes the emission limits from the SI NSPS. These emission limits apply only to engines greater than or equal to 100 HP.

SI NSPS (40 CFR 60 Subpart JJJJ) Emission Limits
(used in the 2020 and 2030 emission factors)

Pollutant	Stage 1 (1/1/2008)	Stage 2 (1/1/2010)	Units
CO	4	2	g/bhphr
VOC	1	0.7	g/bhphr
NO_x	2	1	g/bhphr

Since the NSPS emission limits only apply to new or reconstructed units, it is important to have an estimate of the annual population turnover. Based on information in the regulatory dockets, we assume that 5% of the RICE population will be a new unit, either through replacement or new additions, in any given year. Therefore, ERG assumes that from 2013 to 2020, about 35% of the population as of 2020 would consist of new units from the date of the 2013 baseline. We further assumed, based on population data from regulatory support documents, that only 36 percent of these new units would be 100 HP or greater, meaning only 12 percent of the total population would be subject. We would further anticipate that some of these units would be subject to the NSPS Stage 1 requirements, while many more will be subject to the Stage 2 NSPS requirements, based on construction date. Due to the two-year applicability date of the NSPS Stage 1 starting in 2008 through 2009, we estimate that about 2% of RICE units will be subject to Stage 1 requirements, and 10% will be subject to the 2010 SI NSPS Stage 2 requirements by 2020, with the remainder being at the baseline emission factor.

In 2030, there will be far more RICE units that were constructed after the January 1, 2010 NSPS Stage 2 applicability date, so that ERG estimates that 28% of RICE units will be subject to Stage 2, the same 2% in 2020 will be subject to Stage 1, the remaining 70% would either be existing units or units too small to be subject to the NSPS.

Due to the NSPS regulations, the CO, VOC and NO_x emission factors get progressively lower in the future, while emissions of the non-regulated pollutants remain essentially the same as the 2013 baseline. The only exception is CO_2 emissions, in which we have added the difference in CO reductions in 2020 and 2030 to the CO_2 estimate to reflect the catalytic oxidation of CO to CO_2 associated with meeting the NSPS requirements. The table below presents the emission factors by year. Where applicable, the range of emission factors identified for different engine types is shown in brackets. Appendix Engine-D contains the specific line-item calculations, assumptions and references used in this analysis.

Natural Gas-Fueled Stationary RICE Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	121.9	122.0	122.3
CH_4	0.86 [0.25 - 1.38]	0.86	0.86
N_2O	0.00024	0.00024	0.00024
Black Carbon	0.0063	0.0063	0.0063
CO	1.6 [0.55 - 2.73]	1.5	1.3
VOC	0.29 [0.18 - 0.39]	0.29	0.27
NO_x	1.8 [1.63 - 2.08]	1.7	1.4
SO_x	0.00065	0.00065	0.00065
PM_{10}-filterable	0.0049 [0.0001 - 0.0105]	0.0049	0.0049
$PM_{2.5}$-filterable	0.0049 [0.0001 - 0.0105]	0.0049	0.0049
Condensable PM	0.011	0.011	0.011

3. Emission Factors for Stationary Combustion Turbines

3.1 Summary

The primary goal of this project is to develop emission factors compatible with the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. This memorandum is a deliverable under contract 3F-31281 with Argonne National Laboratory. Specifically, turbine emission factors provided in this memorandum meet the requirements of Task 10.

ERG developed emission factors for 2013 as well as projections of 2020 and 2030. This memorandum details the sources and approach used to develop these factors for four types of turbine fuels: natural gas, biogas, diesel, , and gasified coal. This memorandum also presents the results of literature searches ERG had previously conducted into emissions data for municipal solid waste gasification.

To determine baseline emission factors for 2013, ERG reviewed EPA's AP-42 compilation of emission factors, EPA's WebFIRE Emission Factor online database, EPA's 2012 Report to Congress, documents from EPA's Climate Leaders program, Intergovernmental Panel on Climate Change guidance documents, and regulatory documents associated with the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Combustion Turbines (40 CFR 63, Subpart YYYY, docket EPA-HQ-OAR-2002-0060) and the Standards of Performance for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK, docket EPA-HQ-OAR-2004-0490). In determining 2013 baseline and projected emission factors for 2020 and 2030, regulatory emission limits and turbine population data were incorporated where applicable and practicable to calculate weighted average emission factors.

The accompanying appendices (GREET TurbinesEFs_021914.xlsx) summarize the emission factors, raw data, and references for turbines burning diesel, natural gas, biogas, and gasified coal. Due to the large number of references used to develop these emission factors, they are noted within the appendices rather than within this memorandum.

3.2 Natural Gas Emission Factors

The majority of natural gas-fired combustion turbines are used at power plants to generate electricity during periods of peak demand. ERG assumed that the natural gas used in these engines has an LHV of 983 Btu/scf and a HHV of 1,089 Btu/scf, and that typical natural gas-fired turbines would be greater than 1MW size. Emission factors are provided in the table below, and details regarding calculations and assumptions are provided in Appendix Turbine-A.

Baseline Emission Factors

EPA's AP-42 chapter on stationary gas turbines provided emission factors for NO_x, condensable PM, filterable PM and total PM. Emission factors were adjusted from a HHV to LHV basis. AP-42 provided separate NO_x factors for uncontrolled emissions and for three control technologies: water-steam injection, lean-premix and SCR. The population of units using each control technology was not available, so the factors were averaged.

The 2012 EPA Report to Congress on Black Carbon reports that for stationary natural gas combustion sources, black carbon composes 38 percent of emitted $PM_{2.5}$ filterable plus condensable PM. ERG therefore calculated the black carbon emission factor for natural gas turbines as 38 percent of the emission factor determined for $PM_{2.5}$ filterable plus condensable PM.

Emission factors for CO_2, CH_4, N_2O, CO, VOC, NO_x, SO_x, PM_{10} and $PM_{2.5}$ are based on factors presented in the 2012 Argonne National Laboratory report, "Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units." ERG converted these values from units of g/kWh to lb/MMBtu, assuming an efficiency of 31.6% for single-cycle turbines and 50.6% efficiency for combined-cycle turbines.

Future Emission Factors

Data indicate that natural gas-fueled turbines are performing at levels that meet or exceed the NSPS emission limits for natural gas turbines, which has limits for NOx and SO_2. Furthermore, the stationary combustion turbine NESHAP establishes limits only for formaldehyde, which is not a pollutant of concern in this analysis. Due to these factors, the 2013 baseline emission factors have also been applied to 2020 and 2030. The tables below present the emission factors by year. Appendix Turbine-A contains the specific line-item calculations, assumptions and references used in this analysis.

Natural Gas-Fueled Single-Cycle Turbine Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	140.8	140.8	140.8
CH_4	0.00280	0.00280	0.00280
N_2O	0.000303	0.000303	0.000303
Black Carbon	0.0049	0.0049	0.0049
CO	0.047 [0.017 - 0.091]	0.047	0.047
VOC	0.00247	0.00247	0.00247
NO_x	0.08 [0.014 - 0.36]	0.08	0.08
SO_x	0.00147	0.00147	0.00147
PM_{10}-filterable	0.007767	0.007767	0.007767
$PM_{2.5}$-filterable	0.007767	0.007767	0.007767
Condensable PM	0.0052	0.0052	0.0052

Natural Gas-Fueled Combined-Cycle Turbine Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	148.0	148.0	148.0
CH_4	0.00287	0.00287	0.00287
N_2O	0.002897	0.002897	0.002897
Black Carbon	0.0021	0.0021	0.0021
CO	0.047 [0.017 - 0.091]	0.047	0.047
VOC	0.00062	0.00062	0.00062
NO_x	0.0228 [0.014 - 0.36]	0.0228	0.0228
SO_x	0.00074	0.00074	0.00074
PM_{10}-filterable	0.000301	0.000301	0.000301
$PM_{2.5}$-filterable	0.000301	0.000301	0.000301
Condensable PM	0.0052	0.0052	0.0052

3.3 Biogas Emission Factors

Biogas, in this analysis, could mean landfill gas or digester gas. Oftentimes, landfill gas-to-energy projects will use small combustion turbines (microturbines) to convert biogas to electric energy. Microturbines are small-scale gas turbines used for distributed electricity generation, electricity cogeneration, and waste-to-energy applications. These units typically produce less than 1 megawatt of power.

Biogas primarily comprises methane and carbon dioxide and may contain small amounts of moisture and hydrogen sulfide (H_2S). The composition of biogas depends on the type of biogas; anaerobic digester gas typically has higher methane content (around 55 to 65 percent) than landfill gas (typically around 50 percent). Emission factors for biogas were disaggregated by biogas type. ERG assumed a heating value of 476 Btu/scf for landfill gas and 600 Btu/scf for digester gas, based on information provided by California's South Coast Air Quality Management District and EPA's WebFIRE Emission Factor database, respectively.

Baseline Emission Factors

The 2012 EPA Report to Congress on Black Carbon reports that for natural-gas combustion from the energy/power industry, black carbon comprises 38 percent of emitted $PM_{2.5}$ filterable plus condensable PM. There were no separate factors provided for biogas; therefore, ERG calculated the black carbon emission factor for biogas turbines as 38 percent of the emission factor determined for $PM_{2.5}$ filterable plus condensable PM.

Emission factors for CH_4 and N_2O are based on default values found in the 2006 IPCC Guidelines for National GHG Inventories. IPCC presented factors on a net calorific value (LHV) basis, so ERG has selected these emission factors for CH_4 and N_2O.

For CO_2, CO, VOC, NO_x, SO_x, $PM_{2.5}$, PM_{10} and condensable PM, ERG searched EPA's WebFIRE database of emission factors.

Future Emission Factors

Data indicate that biogas-fueled turbines are performing at levels that meet or exceed the NSPS emission limits for landfill and digester gas units. Therefore, the 2013 baseline emission factors have been applied to 2020 and 2030. The table below presents the emission factors by year. Appendix Turbine-A contains the specific line-item calculations, assumptions and references used in this analysis.

Biogas-Fueled Turbine Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	38.5 [27 - 50]	38.5	38.5
CH_4	0.01	0.01	0.01
N_2O	0.0002	0.0002	0.0002
Black Carbon	0.0084 [0.0067 - 0.0101]	0.0084	0.0084
CO	0.23 [0.017 - 0.44]	0.23	0.23
VOC	0.0094 [0.0058 - 0.013]	0.0094	0.0094
NO_x	0.15 [0.14 - 0.16]	0.15	0.15
SO_2	0.026 [0.0065 - 0.045]	0.026	0.026
PM_{10}-filterable	0.01981 [0.01477 - 0.02484]	0.01981	0.01981
$PM_{2.5}$-filterable	0.01981 [0.01477 - 0.02484]	0.01981	0.01981
Condensable PM	0.002304 [0.001843 - 0.002765]	0.002304	0.002304

3.4 Diesel Emission Factors

Diesel turbines may be used in electricity generation at utilities or industrial facilities, or as mechanical drivers for pumps or material handling equipment.

Baseline Emission Factors

The 2012 Argonne National Lab report, Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units, provides the most complete set of emission factors for the pollutants of interest. Specifically, factors are provided for CO_2, CH_4, N_2O, CO, VOC, NO_x, SO_x, PM_{10}, and $PM_{2.5}$. ERG converted the factors to a lower heating value (LHV) basis, assuming a higher heating value (HHV) of 137.38 MMBtu per 1,000 gallons and a LHV of 128.45 MMBtu per 1,000 gallons. Factors for CO, PM_{10} and $PM_{2.5}$ were provided for both uncontrolled units and units using water-steam injection to control emissions. The population of diesel turbines using this control technology is unknown. Therefore, ERG averaged the controlled emission factor and the uncontrolled or overall electricity sector emission factor to create the final baseline CO, NO_x, PM_{10} and $PM_{2.5}$ emission factors.

The 2012 EPA Report to Congress on Black Carbon reports that for distillate oil combustion from the energy/power industry, black carbon comprises 10 percent of emitted $PM_{2.5}$ filterable plus condensable PM. Therefore, ERG calculated the black carbon emission factor for diesel turbines as 10 percent of the emission factor determined for $PM_{2.5}$ filterable plus condensable PM.

EPA's AP-42 chapter on stationary gas turbines provided emission factors for CO, NO_x, condensable PM, filterable PM and total PM. Some of these factors were reflected in the 2012 Argonne report discussed above. When used, AP-42 emission factors were adjusted from a HHV to LHV basis.

Future Emission Factors

Data indicate that diesel-fueled turbines are performing at levels that meet or exceed the NSPS NOx emission limits for distillate oil-fired (diesel) turbines. Therefore the 2013 NOx baseline emission factors have been applied to 2020 and 2030. For SO2, however, the new source limit is 0.06 lb/MMBtu, which is lower than the estimated 2013 baseline emission factor. Therefore, as new units subject to the NSPS limits increase their percentage of the distillate oil-fired turbine population, the resulting average emission factor will decrease. The 2020 and 2030 emission factors reflect this reduction over time. The table below presents the emission factors by year. Appendix Turbine-B contains the specific line-item calculations, assumptions and references used in this analysis.

Diesel-Fueled Turbine Emission Factors
(lb/MMBtu)
(Lower Heating Value (LHV) Basis)

Pollutant	2013	2020	2030
CO_2	176.6	176.6	176.6
CH_4	0.00748	0.00748	0.00748
N_2O	0.00150	0.00150	0.00150
Black Carbon	0.002165 [0.0020 - 0.0024]	0.002165	0.002165
CO	0.00431 [0.00431 - 0.08221]	0.00431	0.00431
VOC	0.00054	0.00054	0.00054
NO_x	0.558 [0.261 - 0.558]	0.558	0.558
SO_x	0.1215	0.0969	0.0723
PM_{10}-filterable	0.0394 [0.0122 - 0.0665]	0.0394	0.0394
$PM_{2.5}$-filterable	0.0140 [0.0120 - 0.0160]	0.0140	0.0140
Condensable PM	0.00768	0.00768	0.00768

3.5 Integrated Gasification Combined Cycle Emission Factors

Integrated Gasification Combined Cycle (IGCC) uses gasified coal to fuel a gas turbine and use the gas turbine exhaust to generate steam for use in a steam turbine to produce electrical power. Compared to conventional pulverized coal, IGCC is considered more efficient and produces fewer SO_x, particulate, and mercury emissions. Although commercially demonstrated, the population of IGCC plants in the U.S. is somewhat limited at this time. Emission factors for IGCC are given on an output basis (g/kWh), primarily to help delineate anticipated emission differences when carbon capture and storage control are considered in conjunction with this technology. Emission factors are provided in the table below, and details regarding calculations and assumptions are provided in Appendix Turbine-C.

Baseline Emission Factors

Emission factors for CH_4, and N_2O are based on default values found in the 2006 IPCC Guidelines for National GHG Inventories. IPCC presented factors on a net calorific value (LHV) heat input basis, so ERG has converted these values from kg/TJ to g/kWh using unit conversions and an assumed net efficiency of 34.8%. The efficiency value is the average of the data found in the 2012 Argonne National Laboratory report, Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units. This report also provides emission factors for CO, VOC, NO_x, SO_x, and PM_{10}.

The study Singh et al. (2012) provided emission factors for CO_2, NO_x, SO_2 and total PM for facilities with carbon capture and storage and facilities without. These data were modeled on European IGCC plants and coals, so are presented for comparison, but are not used to develop the emission factors.

Future Emission Factors

The turbine NESHAP and NSPS does not apply to IGCC units that are regulated under the New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units (40 CFR 60, Subpart Da, Docket EPA-HQ-OAR-2005-0031). Subpart Da contains PM, NOx and SO2 emission limits for coal-fired utility units, including IGCCs over 73 MW (250 MMBtu/hr input). The emission factor data indicate that IGCC turbines are performing at levels that meet or exceed the NSPS emission limits for IGCC turbines. Therefore, the 2013 baseline emission factors have been applied to 2020 and 2030. The table below presents the emission factors by year. Appendix Turbine-C contains the specific line-item calculations, assumptions and references used in this analysis, including IGCC population estimate data and conversion of Subpart Da emission limits to the g/kWh format.

IGCC Turbine Emission Factors
(g/kWh)
(Net Output Basis)

Pollutant	2013	2020	2030
CO_2	696.9 [85.7 - 723]	696.9	696.9
CH_4	0.010	0.010	0.010
N_2O	0.016	0.016	0.016
Black Carbon	*Not available*	*Not available*	*Not available*
CO	0.1004	0.1004	0.1004
VOC	0.0057	0.0057	0.0057
NO_x	0.174 [0.174 - 0.3898]	0.174	0.174
SO_x	0.0635 [0.0635 - 0.341]	0.0635	0.0635
PM_{10}-filterable	0.0241	0.0241	0.0241
$PM_{2.5}$-filterable	*Not available*	*Not available*	*Not available*
Condensable PM	*Not available*	*Not available*	*Not available*

3.6 Municipal Solid Waste Gasification Emission Factors

Municipal solid waste (MSW) gasification is an emerging technology that uses municipal solid waste to produce a gaseous fuel product instead of conventional energy sources like coal, oil or natural gas. The gaseous fuel product may then be conditioned and purified for subsequent combustion in a gas engine or turbine, or used for other purposes. By converting waste into a useful energy product, this technology reduces the amount of material sent to landfills and reduces dependence on fossil fuels for power generation.

ERG researched emission factors for this technology, and the results are presented in Appendix Turbine-D. The factors were compiled from a range of data sources, including permits, studies and predictive modeling results. Due to the variety of data sources, the emission factors are presented in a variety of units. Also note that some data presented reflect the product gas from the gasifier, while other data may reflect the stack gases following the engine or turbine combusting the gasifier product gas. At this time, ERG has not standardized the emission factors to a lb/MMBtu or g/kWh basis.

4. Emission Factors and Energy Intensity for Pipelines

4.1 Summary

The primary goal of this project is to develop emission and energy intensity factors compatible with the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. This memorandum is a deliverable under contract

3F-31281 with Argonne National Laboratory. Specifically, pipeline emission and energy intensity factors provided in this memorandum meet the requirements of Task 9.

ERG developed emission and energy intensity factors for pipelines for 2013 as well as projections of 2020 and 2030. This memorandum details the sources and approach used to develop these factors.

4.2 Pipeline Transportation Fuel

ERG assumes that the fuel used by the reciprocating internal combustion engines (RICE) for natural gas transmission conforms to industry standards for pipeline quality natural gas. That is, the gas is at least 75% methane, contains at most 7.0 lbs of water vapor per million cubic feet (mmcf), and contains less than 1 grain of hydrogen sulfide per 100 standard cubic feet (scf) of gas. Based on Argonne National Labs data, we assume this natural gas has a lower heating value (LHV) of 983 Btu/scf, and a higher heating value (HHV) of 1,089 Btu/scf.

4.3 Emission Factors

Based on industry experience in this sector, ERG anticipates that natural gas pipelines will primarily use spark ignition internal combustion engines rated at about 1,000 brake horse power hour (bhp-hr) (based on natural gas transmission sector information in the EPA's 2011 Greenhouse Gas Reporting Program information as of 2/17/2013). Petroleum pipelines, however, will use electric motors as prime mover sources. This discussion, therefore, will focus on the natural gas pipeline compressor engines emission factors.

For the baseline, ERG reviewed documents available in EPA's Climate Leaders program, EPA's AP-42 compilation of emission factors, and regulatory support documents for the Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (40 CFR 60, Subpart JJJJ, docket EPA-HQ-OAR-2005-0030) and the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR 63, subpart ZZZZ, docket EPA-HQ-OAR-2008-0708) to develop the emission factors for natural gas engines for 2013. These assume a distribution between four-stroke lean burn (4SLB) and rich burn (4SRB) engines of 75%, 25% respectively. These two regulations affect emissions of carbon monoxide (CO), nitrogen oxides (NO) and volatile organic carbon (VOC), and have different baseline emission factors depending on whether the engine is lean burn or rich burn. The emission factors for CO, NO_x and VOC reflect the baseline emission factors assumed in these regulations as of 2013, so have not been adjusted further to account for the Subpart JJJJ ("SI NSPS") requirements as in 2020 and 2030.

For 2020 emission factors, ERG estimated the percentages of engines in use that would be subject to either the Stage 1 SI NSPS (applies to units constructed between 1/1/2008 and 12/31/2009), the Stage 2 SI NSPS (applies to units constructed on or after 1/1/2010) standards, or not subject to either of these (i.e., would still have the baseline emission factors). The table below summarizes the emission limits from the SI NSPS.

SI NSPS (40 CFR 60 Subpart JJJJ) Emission Limits
(used in the 2020 and 2030 emission factors)

Pollutant	Stage 1 (1/1/2008)	Stage 2 (1/1/2010)	Units
CO	4	2	g/bhphr
VOC	1	0.7	g/bhphr
NO_x	2	1	g/bhphr

Since the NSPS emission limits only apply to new or reconstructed units, it is important to have an estimate of the annual population turnover. Based on information in the regulatory dockets, we assume that 5% of the RICE population will be a new unit, either through replacement or new additions, in any given year. Therefore, ERG assumes that from 2013 to 2020, about 35% of the population as of 2020 would consist of new units from the date of the 2013 baseline. We would further anticipate that some of these units in the population would be subject to the NSPS Stage 1 requirements, while many more will be subject to the Stage 2 NSPS requirements, based on construction date. Due to the two-year applicability date of the NSPS Stage 1 starting in 2008 through 2009, we estimate that about 6% of RICE units will be subject to Stage 1 requirements, and 29% will be subject to the 2010 SI NSPS Stage 2 requirements by 2020, with the remainder being at the baseline emission factor.

In 2030, there will be far more RICE units that were constructed after the January 1, 2010 NSPS Stage 2 applicability date, so that ERG estimates that 79% of RICE units will be subject to Stage 2, the same 6% in 2020 will be subject to Stage 1, and there will be about 15% of the remaining population of existing units that are not subject to NSPS.

Due to the NSPS regulations, the CO, VOC and NO_x emission factors get progressively lower in the future, while emissions of the non-regulated pollutants remain essentially the same as the 2013 baseline. The only exception is CO_2 emissions, in which we have added the difference in CO reductions in 2020 and 2030 to the CO_2 estimate to reflect the catalytic oxidation of CO to CO_2 associated with meeting the NSPS requirements. The table below presents the emission factors by year. Appendix Pipeline-A contains the specific line-item calculations (such as the RICE heat input rate conversion factor to get from g/bhp-hr to lb/MMBtu), assumptions and references used in this analysis. Due to the large number of references used to develop these emission factors, they are noted within Appendix Pipeline-A and are not repeated in Section 5.0 of this memorandum.

Emission Factor
(lb/MMBtu Lower Heating Value (LHV) Basis [range, if applicable])

Pollutant	2013	2020	2030
CO_2	121.9	122.1	122.4
CH_4	1.10 [0.25-1.38]	1.10	1.10

N_2O	0.00024	0.00024	0.00024
Black Carbon	0.0052	0.0052	0.0052
CO	1.1 [0.55-2.73]	0.970	0.733
VOC	0.339 [0.18-0.39]	0.303	0.242
NO_x	1.74 [1.63-2.08]	1.26	0.545
SO_x	0.0007	0.0007	0.0007
PM_{10} – filterable	0.0027 [0.0001-0.0105]	0.0027	0.0027
$PM_{2.5}$ – filterable	0.0027 [0.0001-0.0105]	0.0027	0.0027
Condensable PM	0.0110	0.0110	0.0110

4.4 Energy Intensity

ERG developed energy intensity factors for natural gas and petroleum pipelines using annual energy consumption and ton-mileage data from the U.S. Department of Energy (DOE) and the Department of Transportation (DOT).

For natural gas pipelines, the total amount of natural gas consumed was obtained from the DOE's Annual Energy Outlook 2012 (Appendix Pipeline-A, Table A2) and the total amount of electricity consumed was obtained from the DOE's Transportation Energy Data Book (Appendix Pipeline-A, Table A.12). These consumption values were converted to common units (trillion Btu/yr) and summed to obtain the total estimated energy consumed for natural gas pipelines in 2009. The number of ton-miles associated with natural gas pipelines (millions) in 2009 was obtained from the DOT's National Transportation Statistics. The 2009 energy intensity factor (Btu/ton-mile) for the higher heating value (HHV) were obtained by dividing the total estimated energy consumed by the total ton-miles for natural gas pipelines. The energy intensity factor at the lower heating value (LHV) was obtained by multiplying the HHV factor by the ratio the LHV and HHV for natural gas.

For petroleum pipelines, the total amount of electricity consumed (million kWh/yr) was estimated by subtracting the total electricity consumed for natural gas pipelines (taken from the DOE's 32nd edition of the Transportation Energy Data Book, Table A.12) from the total electricity consumed for natural gas and petroleum pipelines (taken from the DOE's 30th edition of the Transportation Energy Data Book, Table 2.5). The number of ton-miles associated with oil and oil products (millions) in 2009 was obtained from the DOT's National Transportation Statistics. The 2009 energy intensity factor (Btu/ton-mile) for petroleum pipelines was obtained by dividing the total electricity consumed by the total ton-miles. Appendix Pipeline-B to this memorandum presents the calculations, assumptions and references used to develop these energy intensities.

4.5 References

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U.S. Energy Information Administration. *Annual Energy Outlook 2012*. Appendix A. Table A2: Energy Consumption by Sector and Source. June 2012. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf

5. Emission Factors for Lime Kilns and Portland Cement Kilns

5.1 Summary

The primary goal of this project is to develop emission factors compatible with the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. This memorandum is a deliverable under contract 3F-31281 with Argonne National Laboratory. Specifically, kiln emission factors provided in this memorandum meet the requirements of Task 10.

ERG developed emission factors for 2013 as well as projections for the years 2020 and 2030. This memorandum details the sources and approach used to develop these factors for two separate kiln types: kilns used for lime manufacturing and kilns used for Portland cement manufacturing.

The accompanying appendices (GREET Stationary Combustion EFs - Kilns_120613.xlsx) summarize the emission factors, raw data, and references for lime kilns and cement kilns. Due to the large number of references used to develop these emission factors, they are noted within the appendices rather than within this memorandum.

5.2 Lime Kiln Emission Factors

Lime kilns can be categorized into several different design types: rotary kilns are the most common, constituting about 90 percent of the lime kiln population. The majority of the remaining kilns are vertical kilns. Calcimatic kilns, fluidized bed kilns, and parallel flow kilns are less common. Modern kilns typically have preheaters, which improve thermal efficiency by using hot exhaust gas from the kiln to heat limestone before it enters the kiln. Most kilns generally have some type of particulate control, such as cyclone separators, fabric filters, gravel bed filters, wet scrubbers, or electrostatic precipitators.

Separate emission factors were developed for coal-fired lime kilns and natural gas lime kilns, as described below. To the extent possible, kiln design, preheater use, and common pollution controls were taken into consideration, where applicable. Emission standards in place for particulate matter (PM) were also considered. Factors are presented in units of pounds per ton of lime produced (lb/ton lime).

5.2.1 Coal

To determine emission factors for coal-burning lime kilns, ERG reviewed EPA's AP-42 compilation of emission factors, EPA's WebFIRE Emission Factor online database, default greenhouse gas emission factors provided for the Greenhouse Gas Reporting Program (GHGRP), EPA's 2012 Report to Congress, and regulatory documents associated with the National Emission Standards for Hazardous Air

Pollutants for Lime Manufacturing (Lime Manufacturing NESHAP) (docket EPA-HQ-OAR-2002-0052).

Baseline Emission Factors

EPA's AP-42 chapter on lime manufacturing provides the most complete set of emission factors for the pollutants of interest for coal-fired lime kilns. Specifically, factors are provided in some form for carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NO_x), sulfur oxides (SO_x), filterable PM, and condensable PM. In many cases, these factors were broken down into separate factors based on the presence of a preheater and based on the types of air pollution control devices used. For simplicity, is was assumed that roughly 30 percent of lime kilns have preheaters. Lime kiln population distribution by control type was estimated based on production amounts identified for four different control categories: fabric filters (72 percent), electrostatic precipitators (3 percent), wet scrubbers (22 percent) and gravel bed, cyclone, or uncontrolled (3 percent). Details regarding each calculation and assumptions are provided in Appendix Kiln-A.

For CO_2 and CO, the final baseline emission factors are based on weighted averages of AP-42's factors provided for a coal-fired rotary kiln and a coal-fired rotary kiln with preheater, multiclone, water spray, and fabric filter. For CO_2, the provided factor accounts for the emissions resulting from the reduction of carbonate in the limestone to CO_2 as well as the oxidation of carbon in the fuel. According the AP-42 chapter on lime manufacturing, CO_2 emissions from carbonate reduction can range from about 1,600 to 1,800 pounds per ton of lime produced. For NO_x, the final baseline emission factor is based on AP-42's emission factor provided for a coal-fired rotary kiln, because no other information was available to determine a weighted average. For SO_x, AP-42 emission factors for sulfur dioxide (SO_2) and sulfur trioxide (SO_3) were summed, where available, and these sums were weighted within the no preheater and preheater subcategories based on the control distribution assumptions noted above. The final SO_x emission factor is the weighted average of these results. Note, however, that SO_2 emissions are highly dependent on the sulfur content of the fuel and raw material entering the kiln, so emission factors may vary significantly from plant to plant.

For PM_{10} and $PM_{2.5}$, control-specific particle size distribution data from AP-42 were applied to AP-42's filterable PM emission factors for non-preheater coal-fired rotary kilns. A weighted average, based on control type, was calculated for the resulting values. Note that AP-42 emission factors for PM varied significantly, a result of there being independent data sets for different control scenarios. No particle size distribution data were provided for kilns with preheaters, so we have assigned the weighted PM factors to all coal-fired preheater kilns as well as non-preheater kilns. For condensable PM, the same weighting methodology was applied to the sum of the emission factors provided for inorganic and organic condensable PM.

Further adjustments were made to PM_{10} and $PM_{2.5}$ emission factors with the incorporation of PM emission standards for lime kilns. The table below summarizes the emission limits from the Lime Manufacturing NESHAP.

Lime Manufacturing NESHAP (40 CFR 63 Subpart AAAAA) Emission Limits

Pollutant	Existing (Startup prior to 1/5/2004)		New (Startup after 1/5/2004)	Units
	No wet scrubber	Wet scrubber		
PM	0.12	0.6	0.1	Lb/ton feed

Based on Information Collection Requests (ICR) estimates for the number of units subject to the Lime Manufacturing NESHAP, ERG estimated the fraction of total lime kilns that in 2013 would be subject to the NESHAP PM limit for new sources and the fraction of total lime kilns that would be subject to the PM limit for existing sources (which was further broken down based on whether or not an existing unit had a wet scrubber). In all, ERG estimated that 64 percent of units would be subject to the NESHAP in 2013. Corresponding limits were multiplied by these fractions, and the remaining unaffected fraction was multiplied by the weighted, AP-42-based emission factors for PM_{10} and $PM_{2.5}$. We assumed condensable PM would not be affected by the regulations because the controls that could be needed to comply would significantly affect only the filterable portion of the total PM, while the condensable portion would not be captured. Please see Appendix Kiln-A for further details and assumptions made in developing these emission factors.

The 2012 EPA Report to Congress on Black Carbon reports that for lime kilns, black carbon constitutes 2 percent of emitted $PM_{2.5}$ primary (filterable + condensable). ERG therefore calculated the black carbon emission factor for lime kilns as 2 percent of the emission factors determined for $PM_{2.5}$-filterable plus condensable PM.

Emission factors for nitrous oxide (N_2O) and methane (CH_4) are based on default values that were provided in the GHGRP for stationary combustion sources combusting coal. These values are based on net calorific values according to Intergovernmental Panel on Climate Change (IPCC) guidance documents (which contain the same emission factors), so no additional conversions were necessary to produce lower heating value (LHV)-based emission factors for these pollutants. Units were presented in kilograms per million Btu and were converted to a production basis assuming 7 gigajoules per metric ton of lime produced.

Not enough data were available in our reviewed sources to determine a VOC emission factor for coal-burning lime kilns. EPA's Webfire Emission Factor database provided a VOC emission factor for vertical kilns, but these kilns do not typically burn coal. We have therefore adopted the VOC emission factor determined for cement kilns.

Future Emission Factors

Based on ICR estimates for the number of units subject to the Lime Manufacturing NESHAP, we estimated the fraction of total lime kilns that in 2020 and 2030 are expected to be subject to the NESHAP PM limit for new sources and the fraction of total lime kilns that are expected to be subject to the PM limit for existing sources (which was further broken down based on whether or not an existing unit had a wet scrubber).

Corresponding limits were multiplied by these fractions, and the remaining unaffected fraction was multiplied by the weighted, AP-42-based emission factors for PM_{10} and $PM_{2.5}$. Please see the Appendix Kiln-A for further details and assumptions made in developing these emission factors.

For 2020, we anticipate that 67 percent of lime kilns will be subject to the NESHAP PM emission limits (39 percent as existing units with no wet scrubbers, 11 percent as existing units with wet scrubbers, and 17 percent as new sources constructed after 2002). For 2030, we anticipate that 69 percent of lime kilns will be subject to NESHAP PM emission limits (35 percent as existing units with no wet scrubbers, 10 percent as existing units with wet scrubbers, and 24 percent as new sources constructed after 2002).

Due to the NESHAP emission limits, PM_{10}, $PM_{2.5}$, and black carbon emission factors become progressively lower into the future, as a higher percentage of operating kilns become subject to more stringent limits. For other pollutants, we have applied the 2013 emission factors to 2020 and 2030 as there are currently no standards in place to directly regulate their emissions. The table below presents the emission factors by year. Where applicable, the ranges of emission factors identified for different kiln type/control device configurations are shown in brackets. Appendix Kiln-A contains the specific line-item calculations, assumptions and references used in this analysis.

Coal-Fired Lime Kiln Emission Factors (lb/ton lime produced)

Pollutant	2013	2020	2030
CO_2	2960 [2400 - 3200]	2960	2960
CH_4	0.15	0.15	0.15
N_2O	0.021	0.021	0.021
Black Carbon	0.023 [0.0091 - 0.146]	0.022	0.021
CO	2.9 [1.5 - 6.3]	2.9	2.9
VOC	0.090	0.090	0.090
NO_x	3.1	3.1	3.1
SO_x	2.2 [0.51 - 6.4]	2.2	2.2
PM_{10}-filterable	3.0 [0.103 - 42]	2.8	2.5
$PM_{2.5}$-filterable	0.63 [0.036 - 7.32]	0.59	0.54
Condensable PM	0.51 [0.081 - 2.3]	0.51	0.51

5.2.2 Natural Gas

ERG determined emission factors for natural gas-burning lime kilns using the same sources we reviewed for coal-burning lime kiln emission factors (AP-42, WebFIRE, GHGRP, 2012 Report to Congress, and regulatory support documents associated with the Lime Manufacturing NESHAP (docket EPA-HQ-OAR-2002-0052)).

Baseline Emission Factors

EPA's AP-42 chapter on lime manufacturing provides emission factors for natural gas-fired kilns for CO_2, CO, NO_x, SO_2, and PM. These factors were presented separately based on kiln design and based on the types of air pollution control devices used. We were unable to determine population distribution by kiln type for gas-fired kilns, so final emission factors are weighted averages calculated based on population distribution by control type. We estimated lime kiln population distribution by control type based on the production amounts identified for four different control categories: fabric filters (72 percent), electrostatic precipitators (3 percent), wet scrubbers (22 percent) and gravel bed, cyclone, or uncontrolled (3 percent). Details regarding each calculation and assumptions made are provided in Appendix Kiln-A.

The CO_2 emission factor is based on the AP-42 emission factor presented for a gas-fired calcimatic kiln. This factor accounts for the emissions resulting from the reduction of carbonate in the limestone to CO_2 as well as the oxidation of carbon in the fuel. According this AP-42 chapter, CO_2 emissions from carbonate reduction can range from about 1,600 to 1,800 pounds per ton of lime produced.

For CO, the final baseline emission factor is based on a weighted average of AP-42's factors provided for a gas-fired rotary kiln (controls unspecified) and a gas-fired parallel flow kiln with a fabric filter. For NOx, the final baseline emission factor was based AP-42's emission factors provided for a gas-fired rotary kiln (unspecified controls), a gas-fired calcimatic kiln (unspecified controls), and a gas-fired parallel flow kiln with a fabric filter. The SO_x emission factor is based on the AP-42 SO_2 emission factor presented for a gas-fired parallel flow kiln.

For natural gas-burning lime kilns, we have assumed that the $PM_{2.5}$ to PM_{10} ratio for lime kilns will be similar for coal and gas-fired units, since kilns are direct-fired process heaters where the flue gas contains both products of combustion along with exhaust from raw material and product. Therefore, we have applied the coal-fired kiln $PM_{2.5}$:PM_{10} ratio to the PM_{10} data for estimating $PM_{2.5}$ in natural gas-fired lime kilns. The condensable PM emission factor is based on the sum of the AP-42 factors provided for the inorganic and organic components. Emission standards for PM were incorporated into the final PM_{10} and $PM_{2.5}$ emission factors using the same method described above for coal-fired lime kilns. Similar to factors for coal-burning units, AP-42 emission factors for PM for natural gas fired units varied significantly, a result of there being independent data sets for different control scenarios. For kilns subject to the Lime Manufacturing NESHAP PM limit for existing kilns with wet scrubbers, however, the weighted, AP-42-based emission factor were used in place of the PM limit because it was lower than the PM emission limit.

The 2012 EPA Report to Congress on Black Carbon reports that for lime kilns, black carbon constitutes 2 percent of emitted $PM_{2.5}$ primary (filterable + condensable).

ERG therefore calculated the black carbon emission factor for lime kilns as 2 percent of the emission factors determined for $PM_{2.5}$-filterable plus condensable PM.

Emission factors for N_2O and CH_4 are based on default values that were provided in the GHGRP for stationary combustion sources combusting natural gas. These values are based on net calorific values according to IPCC guidance documents (which contain the same emission factors), so no additional conversions were necessary to produce LHV-based emission factors for these pollutants. Units are presented in kilograms per million Btu and were converted to a production basis assuming 7 gigajoules per metric ton of lime produced.

For VOC, the emission factor is based on EPA's Webfire Emission Factor database, which provides a VOC emission factor for vertical kilns.

Future Emission Factors

To determine future emission factors for natural gas, we took the same approach as for coal. Based on ICR estimates for the number of units subject to the Lime Manufacturing NESHAP, we estimated the fraction of total lime kilns that in 2020 and 2030 are expected to be subject to the NESHAP PM limit for new sources and the fraction of total lime kilns that are expected to be subject to the PM limit for existing sources (which was further broken down based on whether or not an existing unit had a wet scrubber). Corresponding limits were multiplied by these fractions, and the remaining unaffected fraction was multiplied by the weighted, AP-42-based emission factors for PM_{10} and $PM_{2.5}$. Please see Appendix Kiln-A for further details and assumptions made in developing these emission factors.

For 2020, we anticipate that 67 percent of lime kilns will be subject to NESHAP PM emission limits (39 percent as existing units with no wet scrubbers, 11 percent as existing units with wet scrubbers, and 17 percent as new sources constructed after 2002). For 2030, we anticipate that 69 percent of lime kilns will be subject to NESHAP PM emission limits (35 percent as existing units with no wet scrubbers, 10 percent as existing units with wet scrubbers, and 24 percent as new sources constructed after 2002).

Due to the NESHAP emission limits, PM_{10}, $PM_{2.5}$, and black carbon emission factors become progressively lower into the future, as a higher percentage of operating kilns become subject to more stringent limits. For other pollutants, we have applied the 2013 emission factors to 2020 and 2030 as there are currently no standards in place to directly regulate their emissions. The table below presents the emission factors by year. Where applicable, the ranges of emission factors identified for different kiln type/control device configurations are shown in brackets. Appendix Kiln-A contains the specific line-item calculations, assumptions and references used in this analysis.

Natural Gas-Fired Lime Kiln Emission Factors (lb/ton lime produced)

Pollutant	2013	2020	2030
CO_2	2700	2700	2700
CH_4	0.013	0.013	0.013
N_2O	0.0013	0.0013	0.0013
Black Carbon	0.013	0.011	0.011
CO	0.93 [0.45 - 2.2]	0.93	0.93
VOC	0.02	0.02	0.02
NO_x	0.68 [0.15 - 3.5]	0.68	0.68
SO_x	0.0012	0.0012	0.0012
PM_{10}-filterable	0.76 [0.026 - 97]	0.72	0.67
$PM_{2.5}$-filterable	0.18 [0.0053 – 19.9]	0.17	0.16
Condensable PM	0.28 [0.22 - 0.48]	0.28	0.28

5.3.0 Portland Cement Kiln Emission Factors

Portland cement kilns can be categorized into wet process or dry process units (dry process being the most common), and can also be grouped by whether or not they have a preheater or preheater/precalciner. Kilns may have fabric filters or electrostatic precipitators for particulate control.

Although separate emission factors were developed for coal-fired lime kilns and natural gas fired lime kilns, emission data were not disaggregated for the cement kiln industry. Without additional analyses, we are unable to develop separate emission factors for coal and natural gas fuels. To the extent possible, however, kiln design, preheater use, and common pollution controls were taken into consideration, where applicable. Emission standards in place for PM, NO_x, and SO_2 were also considered. Factors are presented in units of pounds per ton of clinker produced (lb/ton clinker).

Baseline Emission Factors

EPA's AP-42 chapter on Portland cement manufacturing provides the most complete set of emission factors for the pollutants of interest for cement kilns. Specifically, factors are provided in some form for CO_2, CO, NO_x, SO_x, PM_{10}, and $PM_{2.5}$. These factors were broken down into separate factors based on kiln design, the presence of a preheater or preheater/precalciner, and the types of air pollution control devices used. Based on supporting documentation for the development of the Portland cement NESHAP, we have assumed the following breakdown for kiln types: roughly 19 percent are wet process kilns, 24 percent are dry process (no preheater/precalciner), 22 percent are preheater kilns, and 35 percent are preheater/precalciner kilns. Details regarding each calculation and assumptions made are provided in Appendix Kiln-B.

It was assumed that CO_2, CO, NO_x, and SO_x emissions are not significantly affected by the type of particulate control in place. Baseline emission factors were calculated as weighted averages of AP-42's factors provided for each of the four categories listed above. Further adjustments were made to the SO_x and NO_x emission factors, assuming that 7 units (or about 3 percent) would be subject in 2013 to the NSPS limits for these pollutants. A summary of the applicable emission limits from the Portland Cement NSPS is provided in the table below. The estimate for the affected fraction of units is based on information provided to EPA by the Portland Cement Association to support the development of the standards (Please see the Appendix Kiln-B for calculations and sources).

Portland Cement NSPS (40 CFR 60 Subpart F) Emission Limits

Pollutant	Existing Constructed/Reconstructed on or before 6/16/2008	New Constructed/Reconstructed after 6/16/2008	Units
SO_2	--	0.4	lb/ton clinker
NO_x	--	1.5	lb/ton clinker

For PM_{10} and $PM_{2.5}$, control-specific particle size distribution data from AP-42 were applied to AP-42's PM emission factors for wet and dry process kilns. Separate particle size distribution data were not provided for preheater and preheater/precalciner kilns, so we applied the dry process data here as well to determine PM_{10} and $PM_{2.5}$ emission factors for these units. Resulting PM_{10} and $PM_{2.5}$ values for each available control type were then averaged, because no control distribution data were readily available for Portland cement kilns.

Further adjustments were made to PM emission factors with the incorporation of PM emission standards for cement kilns. PM emission limits from the Portland Cement NESHAP are summarized in the table below.

Portland Cement NESHAP (40 CFR 63 Subpart LLL) Emission Limits

Pollutant	Existing Constructed/Reconstructed on or before 5/6/2009	New Constructed/Reconstructed after 5/6/2009	Units
PM	0.07	0.02	lb/ton clinker

Based on Portland Cement NESHAP supporting documents, we estimated the fraction of total cement kilns that in 2013 would be subject to the Portland Cement NESHAP PM limit for new sources and the fraction of total lime kilns that would be subject to the PM limit for existing sources. Corresponding limits were multiplied by these fractions, and the remaining unaffected fraction was multiplied by the weighted, AP-42-based emission factors for PM_{10} and $PM_{2.5}$. Please see Appendix Kiln-B for further details and assumptions made in developing these emission factors.

The 2012 EPA Report to Congress on Black Carbon reports that for cement kilns, black carbon constitutes 3 percent of emitted $PM_{2.5}$ primary (filterable + condensable). ERG therefore calculated the black carbon emission factor for lime kilns as 3 percent of the emission factors determined for $PM_{2.5}$-filterable plus condensable PM.

Emission factors for N_2O and CH_4 are based on default values that were provided in the GHGRP for stationary combustion sources combusting coal. These values are based on net calorific values according to IPCC guidance documents (which contain the same emission factors), so no additional conversions were necessary to produce LHV-based emission factors for these pollutants. Units were presented in kilograms per million Btu and were converted to a production basis assuming 7 gigajoules per metric ton of lime produced.

Emission factors for VOC were not readily available for cement kilns; however, AP-42 provided emission factors for total organic compounds (TOC). As a conservative estimate for VOC, a weighted average of these factors, based on kiln type, were calculated.

Future Emission Factors

Based on estimates for the number expected units to be subject to Portland Cement NESHAP and NSPS limits (found in supporting documents for the regulations (EPA-HQ-OAR-2002-0051)), ERG determined the fraction of total kilns that in 2020 and 2030 are anticipated to be subject to limits for each pollutant of interest. Corresponding limits were multiplied by these fractions, and the remaining unaffected fraction was multiplied by the weighted, AP-42-based emission factors for PM_{10}, $PM_{2.5}$, NO_x, and SO_2. Please see Appendix Kiln-B for further details and assumptions made in developing these emission factors.

For 2020, we anticipate that 73 percent of cement kilns will be subject to the Portland Cement NESHAP PM emission limits (52 percent as existing units and 21 percent as new sources). Furthermore, we expect that 18 percent of cement kilns will be subject to the NSPS emission limits for NO_x and SO_2. For 2030, we anticipate that 82 percent of cement kilns will be subject to NESHAP PM emission limits (41 percent as existing units and 41 percent as new sources). We expect that 33 percent of cement kilns in 2030 will be subject to the NSPS emission limits for NO_x and SO_2

Due to the NESHAP and NSPS emission limits, PM_{10}, $PM_{2.5}$, black carbon, NO_x, and SO_x emission factors become progressively lower into the future, as a higher percentage of operating kilns become subject to more stringent limits. For other pollutants, we have applied the 2013 emission factors to 2020 and 2030 because there are currently no standards in place to directly regulate their emissions. The table below presents the emission factors by year. Where applicable, the ranges of emission factors identified for different kiln type/control device configurations are shown in brackets.

Appendix Kiln-B contains the specific line-item calculations, assumptions and references used in this analysis.

Cement Kiln Emission Factors (lb/ton clinker produced)

Pollutant	2013	2020	2030
CO_2	1857 [1800 - 2100]	1857	1857
CH_4	0.15	0.15	0.15
N_2O	0.021	0.021	0.021
Black Carbon	0.064 [0.0028 - 1.35]	0.057	0.042
CO	1.6 [0.12 - 3.7]	1.6	1.6
VOC	0.094 [0.028 - 0.18]	0.094	0.094
NO_x	5.2 [1.5 - 7.4]	4.7	4.1
SO_x	4.3 [0.4 - 10]	3.7	3.1
PM_{10}-filterable	4.8 [0.017 - 105]	4.2	3.0
$PM_{2.5}$-filterable	1.9 [0.0097 - 45]	1.6	1.1
Condensable PM	0.25 [0.033 - 0.89]	0.25	0.25