Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022

Final Report | Report Number 25-02 | December 2024

NEW YORK STATE

NYSERDA
New York State Energy Research and Development Authority

50 YEARS 1975-2025

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Our Mission:

Advance clean energy innovation and investments to combat climate change, improving the health, resiliency, and prosperity of New Yorkers and delivering benefits equitably to all.

Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

New York State Department of Environmental Conservation

Albany, NY

Macy Testani
Project Manager

Prepared by:

Eastern Research Group, Inc.

Concord, MA

NYSERDA Report 25-02 NYSERDA Contract 150851 December 2024

Notice

Preferred Citation

New York State Energy and Research Development Authority (NYSERDA). 2024. "Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2022, Final Report," NYSERDA Report Number 25-02. Prepared by Eastern Research Group Inc., Concord, MA. nyserda.ny.gov/publications

Abstract

In July 2019, the New York State Legislature passed the Climate Leadership and Community Protection Act (Climate Act). The Climate Act requires the establishment of statewide limits to greenhouse gases (GHG) as a percentage of 1990 emissions (i.e., 60% by 2030 and 15% by 2050), which will put New York State on a path to achieve the overarching goal of carbon neutrality by midcentury. The Climate Act also requires using 20-year global warming potentials (GWPs) and the inclusion of out-of-state emissions associated with the extraction and transmission of fossil fuels for consumption within the State. This requirement necessitates using emission factor data for an upstream fossil fuel cycle that covers extraction, processing, and transmission/distribution of natural gas, coal, and petroleum into the State. This report documents the methods and results for the Climate Act–compliant energy sector GHG inventory through 2022 and tracks GHG emission progress within New York State's (NYS) energy sector year-by-year. GHGs included in the energy sector inventory are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

Total energy sector emissions were 297 million metric tons of carbon dioxide equivalent (MMT CO_2e) in 2022. Emissions per capita peaked in 2000 but fell to a low of 13.1 metric tons of carbon dioxide equivalent (MT CO_2e) per person in 2020 during the coronavirus disease 2019 (COVID-19) pandemic before rebounding to 15.1 MT CO_2e per person in 2022 (OpenNY 2024). In-state emissions of CO_2 contributed 64.8% (192.7 MMT CO_2e) to total GHGs in 2022. Combustion and upstream emissions for the transportation sector remained the largest source of energy sector emissions in the State in 2022, totaling 111.7 MMT CO_2e. Electricity emissions were the next largest contributing sector (62.0 MMT CO_2e), followed by the residential sector (59.8 MMT CO_2e), the commercial sector (36.1 MMT CO_2e), the industrial sector (14.3 MMT CO_2e), and the oil and natural gas sector (13.4 MMT CO2e).

Keywords

greenhouse gas emissions, energy sector, transportation, residential, commercial, industrial, fossil fuel, natural gas, inventory, upstream fuel cycle, fuel combustion, fuel consumption.

Acknowledgments

This report describes the methods and results for the New York State greenhouse gas (GHG) emissions inventory for the year 2022. This report was prepared by Eastern Research Group, Inc. (ERG), an independent contractor to New York State Energy Research & Development Authority (NYSERDA). Synapse Energy Economics developed the methods for producing the imported electricity results. ERG gratefully acknowledges the contributions of NYSERDA and the New York State Department of Environmental Conservation (DEC) in developing this energy sector GHG inventory.

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Abbreviations

AR4	*Fourth Assessment Report*
AR5	*Fifth Assessment Report*
AFVT	Alternative Fuel Vehicle and Technology
B0	conventional diesel
B5	5% diesel
bbl	barrels
BTS	Bureau of Transportation Statistics
Btu	British thermal unit
C	carbon
CARB	California Air Resources Board
CC	carbon content
CH_4	methane
Climate Act	New York State Climate Leadership and Community Protection Act
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COVID-19	coronavirus disease 2019
DEC	New York State Department of Environmental Conservation
E10	gasoline containing up to 10% ethanol
E85	gasoline containing 70–85% ethanol
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERG	Eastern Research Group, Inc.
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
g	gram
g/GJ	grams per gigajoule
g/kj	grams per kilojoule
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GJ	gigajoule
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation model
GWP	global warming potential
HPMS	Highway Performance Monitoring System
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent System Operator

ISO NE	Independent System Operator New England
kg	kilogram
ktons	kilotons (thousands of tons)
lb	pounds
lb/mmBtu	pounds per million British thermal units)
LPG	liquefied petroleum gas
mmBtu	million British thermal units
MMCF	million cubic feet
$MMCO_2e$	metric tons of carbon dioxide equivalent
$MMMCO_2e$	million metric tons of carbon dioxide equivalent
MOVES	Motor Vehicle Emission Simulator (model)
MT	metric ton
MT/10^9 Btu	metric tons per 10^9 Btu
MW	megawatt
N_2O	nitrous oxide
NAS	National Academies of Sciences, Engineering, and Medicine
NEI	National Emissions Inventory
NETL	National Energy Technology Laboratory
NHTSA	National Highway Traffic Safety Administration
NYISO	New York Independent System Operator
NYS	New York State
NYSERDA	New York State Energy Research & Development Authority
OITS	New York State Office of Information Technology Services
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
PADD	Petroleum Administration for Defense District
PJM	Pennsylvania, (New) Jersey, Maryland
PRELIM	The Petroleum Refinery Life Cycle Inventory Model
SAFE	safer affordable fuel-efficient
SEDS	State Energy Data System
SIT	State Inventory Tool
t	tons
VIUS	Vehicle Inventory and Use Survey
VMT	vehicle miles traveled

Executive Summary

In July 2019, the New York State (NYS) Legislature passed the Climate Leadership and Community Protection Act (Climate Act), requiring the establishment of statewide limits to greenhouse gases (GHG) as a percentage of 1990 emissions (i.e., 60% by 2030 and 15% by 2050), which will put the State on a path to achieve the overarching goal of carbon neutrality by midcentury. The Climate Act also requires using 20-year global warming potentials (GWP) and including out-of-state emissions associated with extracting and transmitting fossil fuels for consumption within the State. This requirement necessitates using emission factor data for an upstream fossil fuel cycle that covers extraction, processing, and transmission/distribution of natural gas, coal, and petroleum into the State. This report documents the methods and results for the Climate Act-compliant energy sector GHG inventory through 2022 and tracks GHG emission progress within the NYS energy sector year-by-year. GHGs included in the energy sector inventory are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The following source categories are included:

Table ES-1. New York State Greenhouse Gas Source Categories for the Energy Sector

Source Categories
Fuel combustion: • Electricity generation • Residential • Commercial • Industrial
Fuel combustion, transportation: • On-road motor vehicles • Aviation • Railroad • Military • Bunkering (aircraft and vessels) • Other diesel nonroad (e.g., construction, logging) • Gasoline nonroad (i.e., agricultural, construction, industrial/commercial, lawn and garden, marine/boating, public nonhighway, recreational vehicles, miscellaneous/unclassified)
Oil and gas systems
Net electricity imports
Upstream fuel cycle emissions associated with imported fossil fuels

Total energy sector emissions were 297 MMT CO_2e in 2022. Emissions per capita peaked in 2000 but fell to a low of 13.1 MT CO_2e per person in 2020 during the coronavirus disease 2019 (COVID-19) pandemic before rebounding to 15.1 MT CO_2e per person in 2022 (OpenNY 2024). In-state emissions of CO_2 contributed 64.8% (192.7 MMT CO_2e) to total GHGs in 2022.

Figure ES-1. Total In-State and Out-of-State Energy Emissions, per Capita Emissions, and Greenhouse Gas Makeup for New York State, 2022

Values in MMT CO_2e.

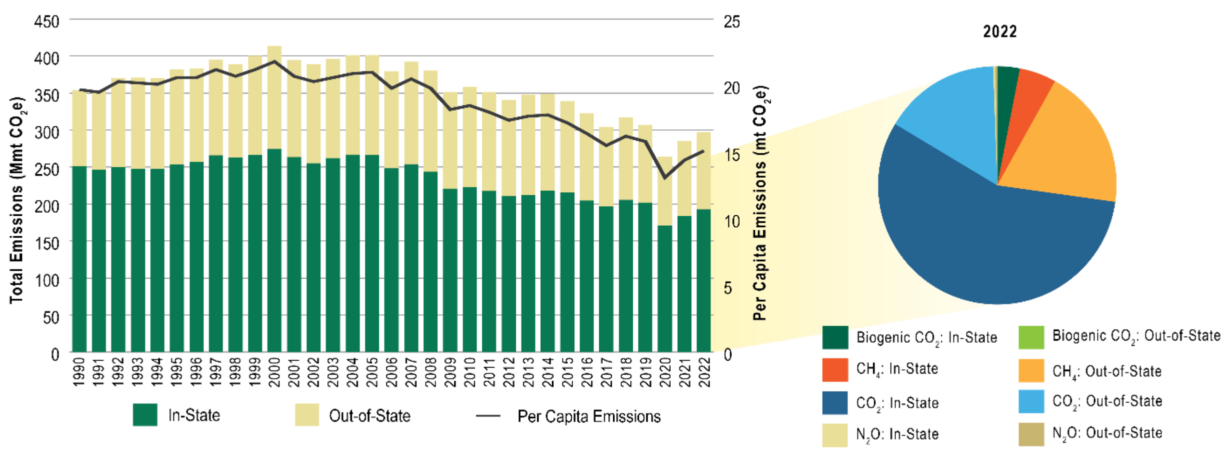


Table ES-2. Total In-State and Out-of-State Energy Emissions for New York State

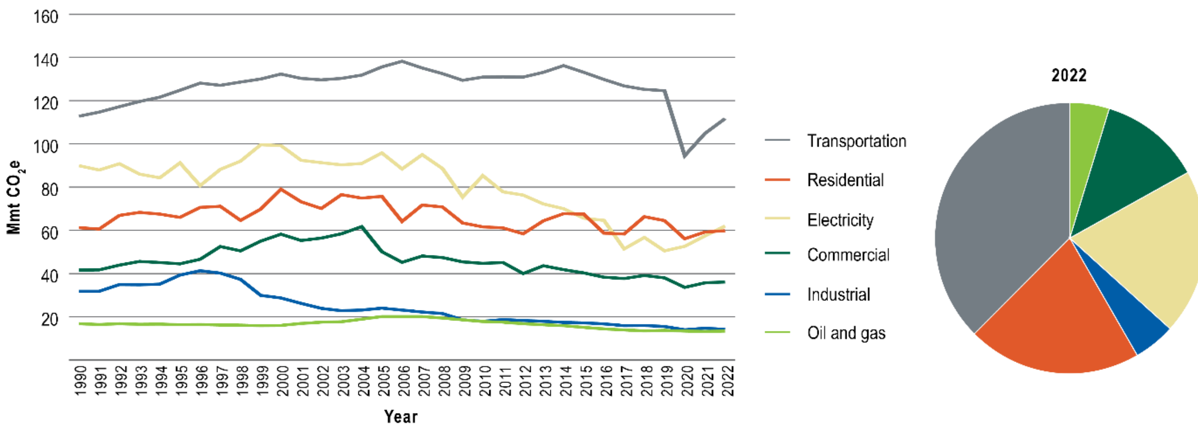
Values in MMT CO_2e.

Emission Category	1990	2000	2010	2015	2019	2020	2021	2022
In-state	251.3	274.2	222.5	215.7	201.9	170.9	183.9	192.7
Out-of-state	102.7	139.1	135.8	123.2	105	93.4	101.1	104.3
Total	354	413.3	358.3	338.9	306.9	264.3	285	297

Combustion and upstream emissions for the transportation sector remained the largest source of energy sector emissions in the State in 2022, totaling 111.7 MMT CO_2e. Electricity emissions were the next largest contributing sector (62.0 MMT CO_2e), followed by the residential sector (59.8 MMT CO_2e), the commercial sector (36.1 MMT CO_2e), the industrial sector (14.3 MMT CO_2e), and the oil and natural gas sector (13.4 MMT CO_2e).

Figure ES-2. New York State Energy Emissions by Sector

Values in MMT CO_2e.



1 Introduction

In July 2019, the New York State (NYS) Legislature passed the Climate Leadership and Community Protection Act (Climate Act), requiring the establishment of statewide limits to greenhouse gas (GHG) emissions as a percentage of 1990 emissions (i.e., 60% by 2030 and 15% by 2050), which will put the State on a path to achieve the overarching goal of carbon neutrality by midcentury. The Climate Act also requires using 20-year global warming potentials (GWP) and including out-of-state emissions associated with extracting and transmitting fossil fuels for consumption within the State. This requirement necessitates using emission factor data for an upstream fossil fuel cycle that covers extraction, processing, and transmission/distribution of natural gas, coal, and petroleum into the State.

The Climate Act also requires preparing an annual statewide GHG emissions report. An economywide inventory method provides the foundation for a comprehensive, transparent, and readily updatable statewide GHG emissions inventory. This report documents the methods and results for the Climate Act–compliant energy sector GHG inventory through 2022.

1.1 Objectives

This study aims to update the NYS energy sector's GHG emissions inventory to provide the input required by the Climate Act. This updated inventory tracks GHG emission progress within the NYS energy sector year-by-year. The emissions data serve as a basis for calculating and evaluating future emission reduction measures. This report documents the methods used for the energy sector GHG inventory and presents energy sector GHG inventory results. The emission factors used in the inventory are provided in the report appendices.

1.2 New York State Energy Sector Greenhouse Gas Inventory Scope

This section describes the scope of the NYS energy sector GHG inventory, including year(s) and temporal resolution, geographic domain and spatial resolution, specific GHGs, and source sectors and categories covered by the estimates.

1.2.1 Years and Temporal Resolution

This report documents the NYS energy sector GHG Inventory approach for the years 1990–2022. Emissions are estimated annually (i.e., metric tons per year). The following describes the NYS energy sector GHG Inventory geographic domain and spatial resolution:

- The NYS energy sector GHG Inventory includes all energy sector GHG emissions emitted from sources located and operating within State boundaries.
- The NYS energy sector GHG Inventory also includes emissions associated with upstream emissions from imported electricity and fossil fuels consumed within the State. Sections 2.2 and 2.3 provide details on establishing boundaries for the upstream imported fossil fuels and electricity.

1.2.2 Specific Greenhouse Gases

The following GHGs are incorporated in this analysis:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)

These GHGs are characterized by carbon dioxide equivalent (CO_2e). CO_2e is calculated by multiplying the individual GHG species by its GWP. The GWP represents the total contribution to global warming resulting from the emission of one unit of a gas relative to one unit of the reference gas, CO_2, which is assigned a value of 1. The CO_2e values in this energy sector inventory are calculated using the GWP values for 20-year and 100-year timeframes as published in the *Fifth Assessment Report* (AR5) (IPCC 2013). The energy sector inventory also provides CO_2e emissions for 20-year and 100-year timeframes as published in the *Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWPs are an optional sensitivity analysis in the NYS GHG Inventory. Appendix E lists specific GWP characterization factors.

The applied GWPs in the energy sector inventory do not include climate-carbon feedback. Climate-carbon feedback refers to the effect that climate change has on the carbon cycle, which impacts atmospheric CO_2, which in turn changes the climate even more. The AR5 contains GWPs with carbon-climate feedback for the non-CO_2 gases; however, because these GWPs are based on one study only, the Intergovernmental Panel on Climate Change (IPCC) does not recommend using these GWPs for emission inventory development at this time due to high uncertainty.

1.2.3 Source Categories

GHG emission source categories for the energy sector that are both present within NYS boundaries and defined by the 2006 IPCC Guidelines (IPCC 2006b) are included in the NYS energy sector GHG Inventory (see Table 1). This report does not assess sectors other than energy.

While this inventory report represents the best estimate of anthropogenic emissions for the energy sector within NYS, future reports will continue to iteratively review and assess efforts to improve and ensure completeness.

Table 1. New York State Greenhouse Gas Source Categories for the Energy Sector

Source Categories
Fuel combustion: • Electricity generation • Residential • Commercial • Industrial
Fuel combustion, transportation: • On-road motor vehicles • Aviation • Railroad • Military • Bunkering (aircraft and vessels) • Other diesel nonroad (e.g., construction, logging) • Gasoline nonroad (i.e., agricultural, construction, industrial/commercial, lawn and garden, marine/boating, public nonhighway, recreational vehicles, miscellaneous/unclassified)
Oil and gas systems
Net electricity imports
Upstream fuel cycle emissions associated with imported fossil fuels

1.3 Approach

To initiate inventory improvements, Eastern Research Group, Inc. (ERG), reviewed the previous NYS GHG Inventory as well as the U.S. GHG Inventory and the California GHG inventory:

- New York State Greenhouse Gas Inventory (NYSERDA 2019a)
- California Greenhouse Gas Inventory (CARB 2019)
- U.S. Greenhouse Gas Inventory (EPA 2024c)

These three inventories are bottom-up, developed using emission factors, activity data, and process-based models. Appendix A summarizes the review findings and approach decisions. ERG completed a similar review for sources relevant to upstream fuel cycle emissions from imported fossil fuels, and those results are summarized in Tables 16, 20, and 23.

2 Methods

This section explains the selection rationale method for emission estimation, describing the specific method and data sources used. The report is split by emission estimates occurring within and outside State boundaries.

2.1 Energy (In-State)

The team used the following methods to estimate emissions occurring within New York State for the entire 1990–2022 period. Specific details for each source category are described in subsequent subsections, but general methods across source categories are provided below.

To align with international standards, biogenic CO_2 (i.e., biogenic emissions of CO_2) from the combustion of biomass fuels (e.g., wood) and biomass-based fuels (e.g., ethanol, biodiesel) are tracked separately from fossil fuel emissions. This approach follows the reporting requirements from the United Nations Framework Convention on Climate Change and methodological guidelines from the IPCC. The latest U.S. GHG Inventory adopted this approach (EPA 2024c). The calculation of biogenic CO_2 emissions is described in detail below within each source category where relevant.

Appendix B provides the fuel carbon contents, as well as CH_4 and N_2O emission factors used in the in-state energy sector inventory (see Tables 25 and 26).

Example calculations for CO_2 and CH_4 emissions from combustion are shown below. Each section discusses source-category-specific modifications where appropriate.

Equation 1 $$\boldsymbol{CO_{2,Total,y} = \sum_f \left(Fuel_{f,y} \times CC_{f,y} \times \left[\frac{44}{12}\right]\right)}$$

where,

$CO_{2,Total,y}$	= Total annual CO_2 emissions (mt) for all fuels for year y
$Fuel_{f,y}$	= Quantity of fuel f combusted in a given source category for year y (billion British thermal units)
$CC_{f,y}$	= Carbon content of fuel f for year y (mt of C/billion Btu)
44/12	= Ratio of the molecular weight of CO_2 to the molecular weight of C

Equation 2 $$CH_{4,Total,y} = \sum_f \left(Fuel_{f,y} \times EF_{CH4,f} \times [1055.06] \times \left[\frac{1}{1000}\right] \right)$$

$CH_{4,Total,y}$	= Total annual CH_4 emissions (mt) for all fuels for year *y*
$Fuel_{f,y}$	= Quantity of fuel *f* combusted in a given source category for year *y* (billion Btu)
$EF_{CH4,f}$	= CH_4 emission factor for fuel *f* (kg CH_4/trillion joules)
1055.06	= Conversion factor from Btu to joules
1/1000	= Conversion factor from kg to mt

2.1.1 Fuel Combustion: Electricity Generation

GHG emissions from electricity generation fuel combustion are estimated using state-level activity data from the U.S. Energy Information Administration's (EIA) State Energy Data System (SEDS) (EIA 2024a) for six fuel types: coal, distillate fuel oil, natural gas, petroleum coke, residual fuel oil, and wood.

Carbon dioxide emissions for the full-time series are estimated using U.S.-specific carbon content data from the latest U.S. GHG Inventory (EPA 2024c). Methane and N_2O emissions are estimated using U.S.-specific emission factors also from the latest U.S. GHG Inventory (EPA 2024c). All carbon emissions from wood are assumed to be biogenic. Note that this same method and data are used to estimate emissions for the residential, commercial, and industrial source categories as described in sections 2.1.2 through 2.1.4.

The example calculations below represent 1990 CO_2 and CH_4 emissions from electricity sector fuel combustion for natural gas.

Equation 3 $$CO_2 = (236{,}776\ billion\ Btu) \times \left(\frac{14.46\ MT\ C}{billion\ Btu}\right) \times \left(\frac{44\ MT\ CO_2}{12\ MT\ C}\right) = 12{,}553{,}864\ MT\ CO_2$$

Equation 4

$$CH_4 = (236{,}776\ billion\ Btu) \times \left(\frac{1\ kg\ CH_4}{trillion\ joules}\right) \times \left(\frac{1055.06\ joules}{1\ Btu}\right) \times \left(\frac{1\ MT\ CH_4}{1000\ kg\ CH_4}\right)$$
$$= 250\ MT\ CH_4$$

2.1.2 Fuel Combustion: Residential

GHG emissions from residential fuel combustion are estimated using state-level activity data from SEDS (EIA 2024a) for six fuel types: coal, distillate fuel oil, kerosene, liquefied petroleum gas (LPG), natural gas, and wood.

Carbon dioxide emissions for the full-time series are estimated using U.S.-specific carbon content data from the latest U.S. GHG Inventory (EPA 2024c). Methane and N_2O emissions are estimated using U.S.-specific emission factors from the latest U.S. GHG Inventory (EPA 2024c). Distillate fuel oil emission factors are applied to kerosene, and natural gas emission factors are applied to LPG.

2.1.3 Fuel Combustion: Commercial

GHG emissions from commercial fuel combustion are estimated using state-level activity data from SEDS (EIA 2024a) for the following fuel types: coal, distillate fuel oil, kerosene, LPG, natural gas, residual fuel oil, and wood.

Carbon dioxide emissions for the full-time series are estimated using U.S.-specific carbon content data from the latest U.S. GHG Inventory (EPA 2024c). Methane and N_2O emissions are estimated using U.S.-specific emission factors from the latest U.S. GHG Inventory (EPA 2024c). Distillate fuel oil emission factors are applied to kerosene, and natural gas emission factors are applied to LPG.

2.1.4 Fuel Combustion: Industrial

GHG emissions from industrial fuel combustion are estimated using state-level activity data from SEDS for the following fuel types: asphalt and road oil, coal (coking), coal (other), distillate fuel oil, kerosene, LPG, lubricants (industrial), lubricants (transportation), miscellaneous petroleum products, natural gas, petroleum coke, residual fuel oil, special naphthas, waxes, and wood (NYSERDA 2022, EIA 2024a).

The SEDS industrial sector distillate fuel oil sales data comprise four components: industrial space heating and farm use, oil company use, off-highway use, and all other uses. Notably, the oil-company-use sales data (SEDS data series DFOCP) is relatively small, and all-other-use sales data (SEDS data series DFOTP) have been assumed to be zero since 1995. To avoid double counting, the off-highway distillate fuel oil sales quantities (SEDS data series DFOFP) are subtracted from the overall industrial distillate fuel oil sales quantities (see section 2.1.12).

Carbon dioxide emissions are estimated using U.S.-specific carbon content data from the U.S. GHG Inventory (EPA 2024c). Methane and N_2O emissions are estimated using U.S.-specific emission factors from the latest U.S. GHG Inventory (EPA 2024c).

The calculation method is similar to the general calculation method shown in section 2.1; however, additional calculations are needed to account for nonenergy use. Accounting for nonenergy use ensures that consumption of fossil fuels for nonenergy purposes is tracked separately from those used for energy consumption in emissions calculations. Noncombustion use fractions and fuel storage fractions are from EPA's State Inventory Tool (SIT) (EPA 2024d). Only CO_2 is tracked for nonenergy fuel use from industrial sectors, consistent with the U.S. GHG Inventory (EPA 2024c).

An example calculation for CO_2 emissions from industrial sector fuel combustion (excluding biogenic CO_2 from wood) is:

Equation 5

$$\boldsymbol{Fuel_{f,y} = TotalFuel_{f,y} \times (1 - NE_f)}$$

$$\boldsymbol{NonEnergy_{f,y} = TotalFuel_{f,y} \times NE_f \times (1 - Storage_f)}$$

where,

$Fuel_{f,y}$ = Quantity of fuel *f* combusted by industrial sector for year *y* (billion Btu)
$NonEnergy_{f,y}$ = Quantity of fuel *f* consumed by industrial sector for net non-energy purposes for year *y* (billion Btu)
$TotalFuel_{f,y}$ = Quantity of fuel *f* consumed by industrial sector for year *y* (billion Btu)
NE_f = Fraction of fuel *f* consumed used in non-energy use
$Storage_f$ = Fraction of non-energy use stored in product for fuel *f*

Equation 6

$$\boldsymbol{CO_{2,Total,y} = \sum_f \left(Fuel_{f,y} \times CC_{f,y} \times \left[\frac{44}{12}\right]\right)}$$

where,

$CO_{2,Total,y}$ = Total annual CO_2 emissions (mt) for all fuels for year *y*
$Fuel_{f,y}$ = Quantity of fuel *f* combusted by industrial sector for year *y* (billion Btu)
$CC_{f,y}$ = Carbon content of fuel *f* for year *y* (mt of C/billion Btu)
44/12 = Ratio of the molecular weight of CO_2 to the molecular weight of C

Equation 6 also applies to calculating CO_2 emissions for nonenergy purposes.

The example calculation for CH_4 emissions from industrial sector fuel combustion is:

Equation 7

$$\boldsymbol{CH_{4,f,y} = \sum_f \left(Fuel_{f,y} \times EF_{CH4,f} \times [1055.06] \times \left[\frac{1}{1000}\right]\right)}$$

where,

$CH_{4,Total}$ = Total annual CH_4 emissions (mt) for all fuels for year *y*
$Fuel_{f,y}$ = Quantity of fuel *f* combusted by industrial sector for year *y* (billion Btu)
$EF_{CH4,f}$ = CH_4 emission factor for fuel *f* (kg CH_4/trillion joules)
1055.06 = Conversion factor from Btu to joules
1/1000 = Conversion factor from kg to mt

The example calculations in Equation 8 represent 1990 CO_2 and CH_4 emissions from industrial sector fuel combustion for natural gas.

Equation 8 $$Fuel_{NG} = (105{,}117\ billion\ Btu) \times (1 - 0.0351) = 101{,}423\ billion\ Btu$$

$$NonEnergy_{NG} = (105{,}117\ billion\ Btu) \times 0.0351 \times (1 - 0.58420) = 1{,}536\ billion\ Btu$$

$$CO_2 = (101{,}423\ billion\ Btu) \times \left(\frac{14.46\ MT\ C}{billion\ Btu}\right) \times \left(\frac{44\ MT\ CO_2}{12\ MT\ C}\right) = 5{,}377{,}462\ MT\ CO_2$$

$$CH_4 = (101{,}423\ billion\ Btu) \times \left(\frac{1\ kg\ CH_4}{trillion\ joules}\right) \times \left(\frac{1055.06\ joules}{1\ Btu}\right) \times \left(\frac{1\ MT\ CH_4}{1000\ kg\ CH_4}\right)$$
$$= 107\ MT\ CH_4$$

While the calculation in Equation 9 reflects CO_2 emissions from nonenergy fuel use.

Equation 9 $$CO_2 = (1{,}536\ billion\ Btu) \times \left(\frac{14.46\ MT\ C}{billion\ Btu}\right) \times \left(\frac{44\ MT\ CO_2}{12\ MT\ C}\right) = 81{,}431\ MT\ CO_2$$

2.1.5 Fuel Combustion: Transportation—On-Road Motor Vehicles

On-road motor vehicles produce CO_2, CH_4, and N_2O emissions from fuel combustion. On-road vehicles include passenger cars and trucks, commercial light-duty trucks, motorcycles, buses, and heavy-duty trucks fueled by conventional gasoline, gasoline containing up to 10% ethanol (E10), conventional diesel, biodiesel, compressed natural gas (CNG), and gasoline containing 70–85% ethanol (E85).

Multiple data sources characterize emissions from on-road motor vehicles across the time series. The following three methods estimate emissions from on-road motor vehicles:

1. The EPA's Motor Vehicle Emission Simulator (MOVES) model, configured with NYS-specific parameters ERG developed, was used to calculate combustion emissions.
2. Estimates of combustion emissions were calculated based on fuel consumption data from SEDS.
3. A hybrid approach combined fuel consumption data with reported emissions calculated using MOVES for the EPA National Emissions Inventory (NEI).

NYSERDA and DEC implemented the hybrid approach described in the third method for this inventory, characterizing the quantity of blended biofuels (i.e., ethanol and biodiesel) varies by data source. The EPA MOVES model uses a volumetric assumption that changes annually, while SEDS tracks biofuel consumption for transportation by state. Ethanol consumption is reported in the SEDS data series EMTCB, and biodiesel in the SEDS data series BDACB. SEDS categorizes CO_2 emissions from ethanol and biodiesel as biogenic CO_2. Users can select biofuel activity data in the inventory independently of the three previously described methods. For this inventory, NYSERDA and DEC used SEDS data to characterize the biogenic portion of blended fuels. In 2022, the biogenic portions of gasoline and diesel were 7.1% and 4.7%, respectively, on an energy basis.

2.1.6 Eastern Research Group's Motor Vehicle Emission Simulator (Method 1)

The May 2024 release of the EPA's MOVES model (version MOVES 4.0.1, database version movesdb20240104) (EPA 2024a) was used to estimate on-road GHG emissions in New York State (NYSERDA 2019a). MOVES is the EPA's state-of-the-art emissions modeling system for estimating criteria and GHG pollutants from on-road motor vehicles. The model's underlying data are peer-reviewed and derived from analysis of millions of emissions test results and numerous instrumented vehicle and telematics activity studies. These studies produced second-by-second driving schedules, hourly speed distributions, temporal vehicle miles traveled (VMT) patterns, and more. The EPA uses MOVES for GHG rulemaking related to motor vehicles.

A significant advantage of using MOVES is its ability to calculate GHG emissions from on-road fuel combustion (i.e., CO_2, CH_4, and N_2O) within a single model. While calculating CO_2 emissions based on fuel sales is a valid approach, it does not readily provide policymakers with detailed breakouts of the CO_2 emissions by fuel type, vehicle class, vehicle model year, or geographic areas (i.e., counties) contributing to statewide totals. Additionally, fuel sales data might not correspond to combustion locations, and therefore emissions from fuel purchased outside New York State might not be adequately captured in a fuel sales approach.

Using MOVES for GHG emission inventories also supports efforts to consolidate on-road emission modeling inputs across various State regulatory use cases, such as State implementation plans, transportation conformity analyses, GHG assessments, and data submissions for the NEI). MOVES calculates CO_2 emissions based on energy consumption rates and the carbon content of each fuel type. Methane emissions are estimated as a fraction of the total hydrocarbon exhaust emissions. Nitrous oxide emissions are calculated using emission rates in grams per hour (for running exhaust) and grams per start (for start exhaust) derived from emissions tests conducted using the federal test procedure and supplemented with U.S. GHG Inventory data (EPA 2015).

Appendix C provides additional details on MOVES settings and specific data inputs.

2.1.6.1 EIA SEDS Fuel Consumption Method (Method 2)

Under the fuel consumption method, emissions from on-road fuel combustion are estimated using state-level activity data from SEDS (EIA 2024a) for motor gasoline and diesel. Motor gasoline (MGMFP) reflects highway fuel use, while diesel data use the SEDS series DFONP for on-highway use. E85 is not reported separately under this method.

The CO_2 emissions for the full time series are estimated using U.S.-specific carbon content data from the latest U.S. GHG Inventory (EPA 2024c). Methane and N_2O emissions are calculated using on-road emission factors from the IPCC (2006a) (Table 26).

2.1.6.2 Hybrid Approach

Under the hybrid approach, analysts combine emissions data for on-road fuel combustion sourced f rom the EPA's NEI with ERG MOVES data to generate a full time series. Based on the DEC MOVES model, NEI data for New York State are available for 2011, 2014, 2017, and 2020–2022. Analysts extrapolate emissions data for interim years from known years, except for 2018 and 2019, where values are carried forward from 2017. Data for earlier years comes from the ERG MOVES model, described in section 2.1.5.1. Analysts scale fuel-specific combustion activity from SEDS proportionally each year to align CO_2 emissions from these fuels with emissions reported in the MOVES models, enabling consistent fuel-specific emissions estimates.

2.1.7 Fuel Combustion: Transportation—Aviation

GHG emissions from aviation fuel combustion are estimated using state-level data from SEDS for aviation gasoline and jet fuel (EIA 2024a). This method aligns with the latest U.S. GHG Inventory (EPA 2024c) and the 2006 IPCC Guidelines. Before 2019, SEDS assigned aviation fuel data to states based on reporting by fuel suppliers. Since 2019, the Bureau of Transportation Statistics (BTS) data has been used for years since 2010 to better reflect the supply and use of aviation fuels across state borders. For consistency in years before 2010, the NYS GHG Inventory sums fuel-use quantities for New York State and New Jersey, multiplying the total by New York State's fraction of passenger, freight, and mail revenue miles relative to the combined miles. Revenue mile data come from BTS (BTS 2024).

BTS reported the fraction of international flight miles and used it to estimate the percentage of jet fuel consumed for international aircraft bunkers (i.e., international flights). This percentage was excluded from NYS jet fuel consumption. International aircraft bunkers do not consume aviation gasoline, so no further adjustment is needed. Emissions from aircraft bunkering are included in section 2.1.11.

The CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (EPA 2024c). Modern jet engines emit CH_4 during low power and idle operations but consume CH_4 at higher power modes. Over the entire operating range, jet engines are net consumers of CH_4, resulting in a zero CH_4 emission factor for jet fuel consumption (EPA 2024c).

2.1.8 Fuel Combustion: Transportation—Railroads

GHG emissions from railroad fuel combustion are estimated using state-level sales SEDS data for distillate fuel oil (EIA 2022). Railroad-use distillate and residual fuel oil sales data are reported under SEDS data series DFRRP and RFRRP, respectively. However, EIA discontinued reporting railroad distillate fuel oil sales in 2020. For 2021 and 2022, railroad distillate fuel oil sales were extrapolated using recent years' data. Historical distillate fuel oil sales for railroads were divided by annual total transportation sector distillate fuel oil sales (SEDS DFTRP) to calculate yearly contribution factors for 2016–2020. These factors were averaged and multiplied by total distillate transportation sector distillate fuel oil sales for 2021 and 2022. Residual fuel sales for railroads in NYS were reported as zero for 1990–2022 and are not included in the inventory. CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (EPA 2024c). The biogenic portion of diesel (i.e., biodiesel content) is based on reported biodiesel consumption from SEDS (BDACB) relative to total diesel used in transportation. This fraction calculates biogenic CO_2 in all transportation categories where diesel is consumed.

2.1.9 Fuel Combustion: Transportation—Military Use

GHG emissions from military transportation are estimated using state-level data from SEDS for distillate and residual fuel oil (EIA 2022). Military-use distillate fuel oil sales data are reported under SEDS data series DFMIP, while residual fuel oil sales data are reported under the series RFMIP. Analysts applied the methods discussed in section 2.1.8, initially developed for estimating distillate fuel oil sales for railroad activities, to calculate military-use distillate fuel oil sales for 2021 and 2022.

Unlike railroad activities, residual fuel oil sales for military use have historically been reported, although EIA has discontinued this data series. Analysts extrapolated 2021 and 2022 residual fuel oil sales using similar methods to those developed to manage discontinued distillate fuel oil reporting. Specifically, they divided historical residual fuel oil sales values for railroad activities by annual total transportation sector distillate fuel oil sales (EIA data series RFTRP) to generate yearly contribution factors for 2016–2020. The average of these contribution factors was multiplied by total residual fuel oil sales to the transportation sector for 2021 to estimate residual fuel oil sales for military use.

The CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions using U.S.-specific emission factors (EPA 2024c). Biogenic CO_2 is calculated based on the biogenic portion of diesel fuel (see section 2.1.8).

2.1.10 Fuel Combustion: Transportation—Vessel Bunkering

GHG emissions from vessel bunkering include all international marine transport activities. Analysts estimate these emissions using state-level data from SEDS for distillate and residual fuel oil (EIA 2022). Distillate fuel oil sales are reported under SEDS data series DFBKP, and residual fuel oil sales data are used under RFBKP. SEDS discontinued these data series in 2021. Analysts calculated vessel-bunkering fuel sales for 2021–2022 using the methods used in sections 2.1.8 and 2.1.9, respectively.

The CO_2 emissions using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (U.S. EPA 2024c). Biogenic CO_2 is calculated based on the biogenic portion of diesel fuel (see section 2.1.8).

2.1.11 Fuel Combustion: Transportation—Aircraft Bunkering

Aircraft bunkering covers international aviation transport activities and is tracked separately from domestic aviation, as described in section 2.1.6.. Analysts estimate emissions for international aircraft bunkers using the methods described for NYS fuel consumption.

The CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (EPA 2024c). This method was chosen because it aligns with the latest U.S. GHG Inventory (EPA 2024c) and the 2006 IPCC Guidelines.

2.1.12 Fuel Combustion: Transportation—Other Nonroad (Diesel)

Fuel combustion from other diesel nonroad-use activities in the transportation sector results in CO_2, CH_4, and N_2O emissions. This section's distillate fuel oil sales data for off-highway-use are reported under SEDS data series DFOFP. To avoid double counting, analysts subtract off-highway distillate fuel oil sales quantities from the overall industrial distillate fuel oil sales (i.e., SEDS data series DFICB) as described in section 2.1.4. As of 2021, these data series have been discontinued, so analysts calculated distillate fuel oil sales for other nonroad activities using the updated methods described in section 2.1.8.

The CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (EPA 2024c). Biogenic CO_2 is calculated based on the biogenic portion of diesel fuel (see section 2.1.7).

2.1.13 Fuel Combustion: Transportation—Other Nonroad (Gasoline)

GHG emissions from other gasoline nonroad use are estimated historically using state-level data from SEDS for motor gasoline (EIA 2024a). The SEDS other gasoline nonroad use sales data consist of eight components:

- Industrial and commercial use (SEDS data series MGIYP)
- Construction use (SEDS data series MGCUP)
- Agricultural use (SEDS data series MGAGP)
- Public nonhighway use (SEDS data series MGPNP)
- Miscellaneous/unclassified use (SEDS data series MGMSP)
- Lawn and garden use (SEDS data series MGLGP)
- Marine/boating use (SEDS data series MGMRP/MGBTP)
- Recreational vehicle use (SEDS data series MGRVP)

The marine/boating–use component consists of two SEDS data series spliced together: marine use from 1990–2014 and boating use from 2015 to the present. In addition, the lawn and garden–use and recreational vehicle–use components are based on SEDS data series that was initiated in 2015; sales data for these two components were backcast for the remainder of the time series based on the NYS population (OITS 2022). For 2021 and 2022, the Federal Highway Administration (FHWA) source datasets these SEDS data series have relied on were used to collect other nonroad gasoline use sales data. Specifically, FHWA Statistics Series tables MF-21 (for MGMFP, MGSFP, and MGPNP) and MF-24 (for MGIYP, MGCUP, MGAGP, MGMSP, MGLGP, MGBTP, and MGRVP) (FHWA 2022a, 2023b).

The CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (EPA 2024c). The emission factors are assumed to be for four-stroke, gasoline-powered equipment in each component. Public nonhighway use and miscellaneous/unclassified use are deemed to be the same as construction equipment. The biogenic fraction of gasoline (i.e., ethanol content) is based on reported ethanol consumption from SEDS (EMTCB) relative to total gasoline consumed for transportation.

2.1.14 Fuel Consumption: Transportation—Natural Gas Pipelines and Distribution

GHG emissions from fuel combustion for natural gas pipeline operations and distribution use are estimated using state-level data from SEDS for natural gas (EIA 2022). These data are reported under SEDS data series NGPZP.

The CO_2 emissions are estimated using U.S.-specific carbon content data, while CH_4 and N_2O emissions are estimated using U.S.-specific emission factors (EPA 2024c).

2.1.15 Oil and Gas Systems

Various processes and equipment associated with the oil and gas sector release CH_4, CO_2, and N_2O into the atmosphere.

The emissions estimation method for oil and gas systems relies on the methane estimates developed for the 1990–2022 NYS Oil and Gas Methane Inventory, a geospatially resolved, bottom-up inventory created using identified best practices (NYSERDA 2024). The Oil and Gas Methane Inventory does not include CO_2 and N_2O estimates for oil and gas systems. Estimates for CO_2 and N_2O are developed using pollutant ratios (i.e., CO_2/CH_4 and N_2O/CH_4) derived from national-level estimates from the U.S. GHG Inventory (EPA 2024c).

To account for uncertainty in emissions estimates from bottom-up approaches, emissions estimates for natural gas systems use a sensitivity analysis within the NYS Oil and Gas Methane Inventory. Further details on the specific adjustments made to methane emissions from that inventory are described in section 2.2.1.1.

Pollutant ratios are designed for oil systems for four segments: exploration, production, transportation, and abandoned oil wells. For natural gas systems, pollutant ratios are developed for seven segments: exploration, gathering and boosting, production, processing, transmission and storage, distribution, and abandoned gas wells. The pollutant ratios are then applied to the CH_4 estimates developed for the NYS Oil and Gas Methane Inventory to estimate CO_2 and N_2O emissions.

The NYS Oil and Gas Methane Inventory does not include GHG emissions from petroleum refineries. EIA data indicate a single operating refinery in New York State in 1990 and 1991 (EIA 2023a). Petroleum refinery emissions are estimated using national-level refinery estimates developed for the U.S. GHG Inventory (EPA 2024c). National-level estimates are scaled to the State based on the ratio of state-to-national crude oil distillation capacity (EIA 2023a).

An example calculation for CO_2 emissions from oil exploration segment is:

Equation 10

$$CO_{2,EXP,NY} = CH_{4,EXP,NY} \times \frac{CO_{2,EXP,US}}{CH_{4,EXP,US}}$$

where,

$CO_{2,EXP,NY}$ = Annual CO_2 emissions from oil exploration in NYS (mt)
$CH_{4,EXP,NY}$ = Annual CH_4 emissions from oil exploration in NYS (mt)
$CO_{2,EXP,US}$ = Annual CO_2 emissions from U.S. oil exploration (mt)
$CH_{4,EXP,US}$ = Annual CH_4 emissions from U.S. oil exploration (mt)

Equation 11

$$CO_{2,EXP,NY} = 210\ metric\ tons\ CH_4 \times \frac{320{,}768\ metric\ tons\ CO_2}{120{,}688\ metric\ tons\ CH_4}$$

$$CO_{2,EXP,NY} = 557\ metric\ tons$$

An example calculation for CH_4 emissions from petroleum refineries is:

Equation 12

$$CH_{4,NY} = CH_{4,US} \times \frac{RefineryCapacity_{NY}}{RefineryCapacity_{US}}$$

where,

$CH_{4,NY}$ = Annual CH_4 emissions from NYS refineries (mt)
$CH_{4,US}$ = Annual CH_4 emissions from U.S. refineries (mt)
$RefineryCapacity_{NY}$ = Crude oil distillation capacity for NYS refineries (bbl/calendar day)
$RefineryCapacity_{US}$ = Crude oil distillation capacity for U.S. refineries (bbl/calendar day)

Equation 13

$$CH_{4,NY} = 24{,}440\ metric\ tons \times \frac{41{,}850 \frac{bbl}{day} \times 365\ days}{15{,}062{,}616 \frac{bbl}{day} \times 365\ days} = 67.9\ metric\ tons$$

2.2 Energy (Imported Fossil Fuels)

The Climate Act requires estimating emissions from imported fossil fuels (i.e., natural gas, petroleum products, and coal). This process involves using upstream fuel-cycle factor data specific to these fuel types. Table 2 lists the fuel types relevant for estimating emissions from upstream fuel-cycle imports. For this inventory, "imported fossil fuel" emissions refer to fuel extraction, processing, transportation, and distribution emissions to the NYS boundary. The upstream fuel cycle excludes emissions from constructing and maintaining infrastructure or equipment manufacturing (e.g., buildings, roads, pipelines, motor vehicles, industrial machinery).

Table 2. Fuel Types Reviewed by End Sector for Upstream Fuel Cycle Emissions

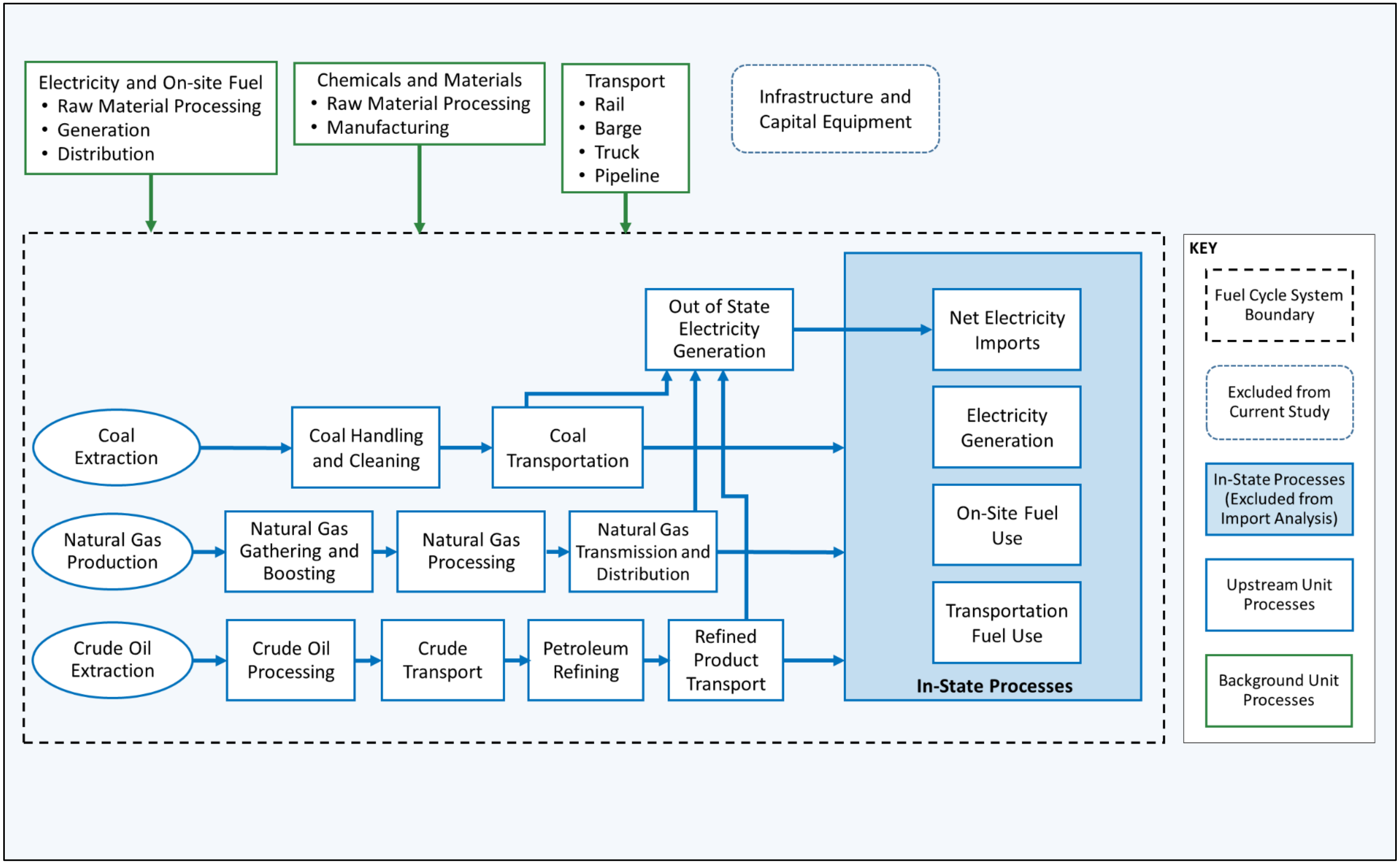
Fuel Type	Electric Power	Transportation	Commercial	Residential	Industrial
Coal	X		X	X	X
Distillate	X	X	X	X	X
Jet fuel		X			
Kerosene			X	X	X
LPG			X	X	X
Motor gasoline		X			X
Diesel		X			
Natural gas	X	X	X	X	X
Residual fuel	X	X	X		X
Other petroleum fuels[a]	X	X	X	X	X

[a] Other petroleum fuels include lubricants, petroleum coke, and unspecified naphthas.

Figure 1 illustrates the system boundaries for the upstream fuel-cycle analysis. Upstream fuel-cycle fossil fuel emissions are included to ensure compliance with the Climate Act. However, the Climate Act does not require inclusion of upstream fuel-cycle factors for non–fossil fuels (e.g., biofuels), so these fuels are excluded from the out-of-state upstream fuel-cycle analysis.

This section details the calculations to estimate upstream fuel-cycle emissions for imported fossil fuels for 1990–2022. To calculate these emissions, upstream fuel-cycle emission factors for each fuel are multiplied by the total fuel consumed yearly in New York State. For blended fuels, upstream fuel-cycle emission factors—derived from the underlying models—reflect only the fossil portion of those fuels. Consequently, these factors are applied only to the estimated non-biogenic content of fuels consumed in the State.

Figure 1. System Boundaries for Upstream Fuel-Cycle Emissions Associated with Imported Fossil Fuels



2.2.1 Natural Gas Upstream Fuel Cycle Imports

The National Energy Technology Laboratory (NETL) developed a natural gas model (NETL 2019) to assess GHG emissions from natural gas extraction, processing, transmission, and distribution in U.S. natural gas basins. ERG used this bottom-up model in openLCA, an open-source life-cycle modeling software application, to source upstream fuel cycle emissions for New York State. However, ERG treated the NETL model as a starting point. To enhance its regional specificity, ERG integrated empirical data from the broader natural gas literature into the NETL model framework to address key uncertainties and develop regionally specific emission factors unique to this inventory.

This approach allowed ERG to address several areas of uncertainty, including skewed emissions from low-producing conventional gas wells (known as super-emitters), uncertainty in shale gas emissions, and discrepancies in natural gas emissions reporting between bottom-up inventories and top-down measurements (both discussed in section 2.2.1.1). ERG also adjusted the NETL model, which reflects 2016 conditions, to account for changes in GHG emission intensity over the time series using data from the U.S. GHG Inventory and variation in transmission distance to the NYS border based on the location of the natural gas source basins.

ERG identified five gas basins in the southern U.S./Gulf Coast and Appalachian regions as conventional and tight natural gas sources from 1990 to the present and shale gas from 2007 onward. For Canadian natural gas emissions, relevant from 1990 to 2013, ERG modeled the emissions as a production-weighted average of the conventional mix from these five U.S. basins for New York State. This approach aligns with data from the Canadian GHG Inventory, which shows a similar emissions profile to the average U.S. basin (Environment and Climate Change Canada 2023).

To backcast natural gas emissions to 1990, ERG adjusted the emission factors within the NETL model using data from Annex 3.6 of the U.S. GHG Inventory (EPA 2024e). This inventory, which serves as the source for the NETL model's emission factors, provides a comprehensive dataset of activity levels and associated emissions throughout the natural gas supply chain, with annual data from 1990. Data in the inventory represent a U.S. national average, and although the inventory offers detailed activity data for parameter-level adjustments, the NETL model lacks the same level of granularity.

Consequently, ERG adopted a higher-level approach to develop stage-level scaling factors for CH_4 and N_2O emissions in the NETL model. For CO_2, ERG implemented stage- and process-level adjustments, as detailed later in this section.

ERG calculated scaling factors by dividing stage-level emissions from the U.S. GHG Inventory by the total annual natural gas production in the U.S. (EIA 2024b). For each stage—production through transmission—ERG compared emissions for a given year to 2016 emissions (the baseline year of the NETL model) on a per-unit basis of natural gas produced.

Table 3 demonstrates an example of a scaling factor calculation for the gathering and boosting stage, and while Table 4 lists all scaling factors applied to the NETL model for 1990. ERG selected 2016 as the baseline year to maintain consistency with the NETL model, which sources data from the U.S. GHG Inventory and the Greenhouse Gas Reporting Program (GHGRP).

Table 3. Natural Gas Scaling Factor Calculation Example

Emission Source/Metric	1990	2016
Gathering and Boosting Net Emissions (t CH_4)	739,066	1,452,988
Total U.S. Natural Gas Production (MMCF)[a]	21,522,622	32,591,578
t CH_4 /MMCF	0.034	0.045

An example of calculated scaling factor from Table 3:

1990 t CH_4/MMCF ÷ 2016 t CH_4/MMCF = 0.034 ÷ 0.045 = 0.77.

[a] Total U.S. natural gas production values taken from EIA (2024c).

Table 4. Natural Gas Scaling Factors Applied to National Energy Technology Laboratory Model for 1990 Conditions

Greenhouse Gas	Natural Gas Stage	Scaling Factor Value
CH_4	Production	1.32
CH_4	Gathering and boosting	0.77
CH_4	Gas processing plants	2.89
CH_4	Transmission and storage	2.51
CH_4	Distribution	4.81
CO_2	Gas processing plants (acid gas removal only)	2.56
N_2O	Production	1.09
N_2O	Gathering and boosting	0.76
N_2O	Gas processing plants	0.00
N_2O	Transmission and storage	1.02
N_2O	Distribution	N/A[a]

[a] U.S. GHG Inventory does not have data on the distribution of N_2O flare emissions.

ERG created new parameters in the NETL model to incorporate the calculated scaling factors directly applied to relevant GHG emissions in each stage. For CH_4, ERG applies scaling factors to emissions from venting without flaring. In contrast, for N_2O, ERG applied scaling factors to emissions from flaring processes, which the U.S. GHG Inventory identifies as the sole source of N_2O emissions. ERG also applied a process-level scaling factor to CO_2 emissions from acid gas removal in Stage 3 (processing) the inventory shows this as the primary source of CO_2 emissions. Additionally, ERG scaled CO_2 emissions from flaring emissions at each relevant stage using the same flaring rates as N_2O.

After applying the scaling factors, ERG used the NETL openLCA model to generate emissions data for each relevant year in the time series.

To adjust the NETL model for NYS-specific conditions, ERG modified transmission pipeline distances. ERG selected large cities near each production basin as natural gas departure points. To avoid potential accounting for emissions associated with the in-state movement of natural gas through pipelines, ERG modeled New York City as the destination for natural gas from the five basins since the City lies along the State boundary. Table 5 lists the origin city for each basin and its corresponding transmission distance to New York City. ERG excluded distribution distances from the imported fuel cycles because they are accounted for in the in-state inventory.

Table 5. Natural Gas Transmission Distances from Basin to New York State Boundary

Basin	Origin City	Destination City	Distance (mi)
Gulf Coast	Houston, TX	New York City, NY	1,420
East Texas	Houston, TX	New York City, NY	1,420
Anadarko	Oklahoma City, OK	New York City, NY	1,320
Arkoma	Fort Smith, AR	New York City, NY	1,170
Appalachia	Pittsburgh, PA	New York City, NY	315

ERG modeled the natural gas production basins supplying gas consumed by New York State as Gulf Coast, East Texas, Arkoma, Anadarko, and Appalachia (see Figure 2). These basins produce conventional, tight, and shale gas and are key sources for NYS gas consumption, as highlighted in a 2006 study prepared for NYSERDA (Rosenberg, Z. and Janney, A. 2006), shown in Figure 3. Although Figure 3 does not identify East Texas as a contributing basin, ERG included it in the model given its proximity to the Gulf Coast basin and the high natural gas production in Texas (EIA 1994). Figure 3 also identifies the Western Canadian Sedimentary Basin as a gas source. EIA data on the international and interstate movement of natural gas (EIA 2024d) indicates that Canadian gas constitutes a significant portion of NYS net gas imports from 1992 to 2010, primarily sourced from Alberta (CER 2020).

Since the NETL model profiles only U.S. basins, ERG modeled Canadian natural gas as a production-weighted average mix of these U.S. basins. EIA data on natural gas gross withdrawals and production (EIA 2024c) began incorporating shale gas production data starting in 2007. Accordingly, ERG modeled shale gas production for the five basins from 2007 to the present. Canadian gas continued to represent a significant portion of NYS net gas imports until 2010 when shale gas from Appalachia began to replace Canadian imports.

Figure 2. Major U.S. Natural Gas Producing Basins

Source: Exhibit 2-2 (NETL 2019)

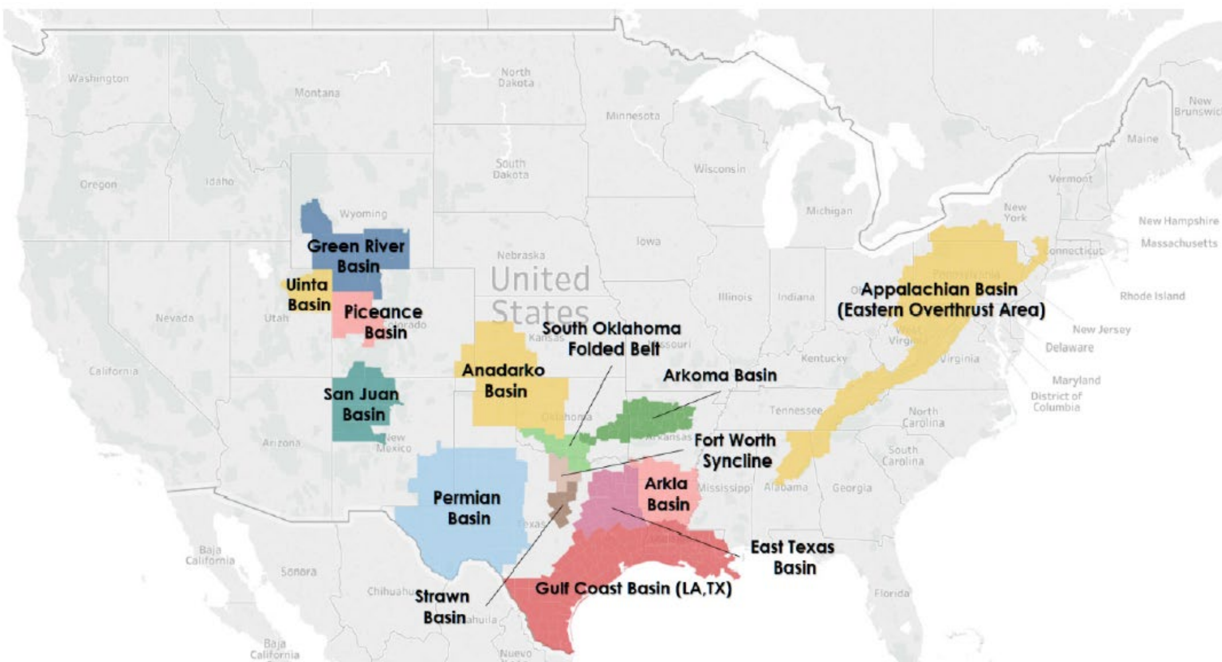
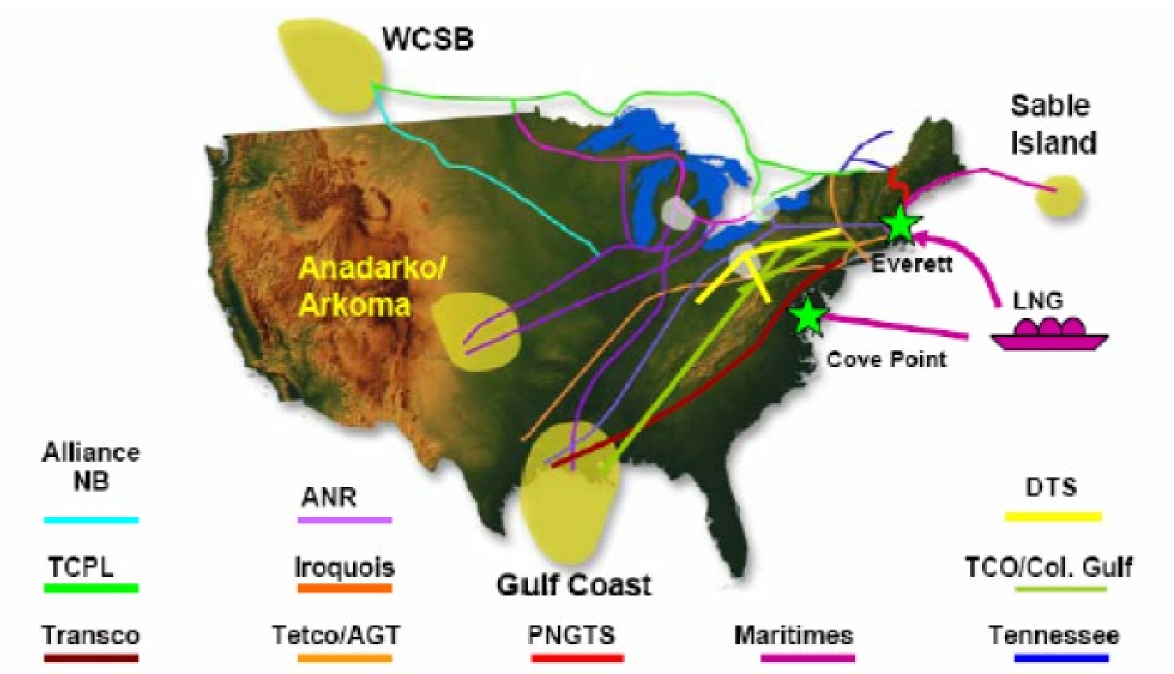


Figure 3. Source Basins for New York State Natural Gas Consumed, 2006

Source: Exhibit IV-2 (ICF 2006).



To calculate an NYS production-weighted aggregate emission rate for imported natural gas consumption, ERG first determined the annual contribution of each basin and gas type to the total gas consumed in New York State. The team obtained state-level production data for Texas, Oklahoma, Arkansas, Pennsylvania, Ohio, Virginia, and West Virginia—all the states covered by the five modeled natural gas basins—from EIA's data on natural gas gross withdrawals and production (EIA 2024c), displayed in Table 6. Because EIA data on shale gas production includes tight gas production, ERG calculated the annual split between shale and tight gas up to 2019 and extrapolated this split for future years (see Table 7) using EIA's *Annual Energy Outlook* (EIA 2023b), and then it applied to the natural gas gross withdrawal data (EIA 2024c) to estimate the portion derived from tight gas plays (Table 8).

Figure 4 visualizes the contribution of each basin and gas type to NYS consumption from 1990 to 2022.

Table 6. U.S. Energy Information Administration Raw Natural Gas Production Data, 2022

State	Conventional (MMCF)	Shale/Tight (MMCF)
Texas	1,918,209	9,676,793
Oklahoma	595,826	2,118,268
Arkansas	67,272	348,114
Ohio	64,192	2,180,770
Pennsylvania	170,350	7,337,720
West Virginia	148,358	2,766,693
Virginia	14,629	275

Table 7. Shale/Tight Gas National Split, 2022

Gas Type	Contribution (%)
Shale	92%
Tight	8%

Table 8. U.S. Energy Information Administration Raw Natural Gas Production Data, 2022

This is an expansion of Table 6 using Table 7.

State	Conventional (MMCF)	Shale (MMCF)	Tight (MMCF)
Texas	1,918,209	8,872,812	803,981
Oklahoma	595,826	1,942,275	175,993
Arkansas	67,272	319,192	28,922
Ohio	64,192	1,999,584	181,186
Pennsylvania	170,350	6,728,078	609,642
West Virginia	148,358	2,536,827	229,866
Virginia	14,629	252	23

Texas, Oklahoma, and Arkansas represent the Gulf Coast, East Texas, Anadarko, and Arkoma, while the other states represent Appalachia. Using Figure 2, the team estimated a basin's percent contribution to its respective state's production based on the approximate area covered by that basin. For example, the Gulf Coast Basin's area is assumed to constitute approximately 40% of Texas's natural gas production area, so it accounts for 40% of Texas's total yearly production (Table 9). Table 10 breaks down the contribution by basin to total annual production for conventional and tight gas in 1990.

Table 9. Percent of State Natural Gas Production Area Covered by Basin

State	Anadarko Basin	Appalachian Basin	Arkoma Basin	East Texas Basin	Gulf Basin
Texas	0%	0%	0%	15%	40%
Oklahoma	50%	0%	25%	0%	0%
Arkansas	0%	0%	65%	0%	0%
Ohio	0%	100%	0%	0%	0%
Pennsylvania	0%	100%	0%	0%	0%
West Virginia	0%	100%	0%	0%	0%
Virginia	0%	100%	0%	0%	0%

Table 10. Contribution to Natural Gas Production by Basin, 1990

State	Basin	% State Contribution (Based on Basin Area)[a]	Total Production (MMCF)[b]	% Contribution to Total Annual Production
Texas			5,754,288	
	Gulf Coast	40%	**2,301,715**	41%
	East Texas	15%	**863,143**	15%
Oklahoma			2,428,463	
	Anadarko	50%	**1,214,232**	22%
	Arkoma	25%	**607,116**	11%
Arkansas			210,112	
	Arkoma	65%	**136,573**	2%
Ohio			154,619	
	Appalachia	100%	**154,619**	3%
Pennsylvania			177,609	
	Appalachia	100%	**177,609**	3%
West Virginia			178,000	
	Appalachia	100%	**178,000**	3%
Virginia			14,774	
	Appalachia	100%	**14,774**	<1%
Total Basin Production			**5,647,781**	100%

[a] See Figure 2.

[b] Based on EIA data for natural gas gross withdrawals and production (EIA 2024c).

In 1990, Canadian gas made up 12.6% of total NYS natural gas imports (EIA 2024d), and in-state production contributed 2.2% of total State consumption (NYSERDA 2024). Therefore, the basins in Table 10 represented approximately 85.2% of gas produced for New York State in 1990. Table 11 shows each basin's contribution adjusted for Canadian and in-state production.

Table 11. Contribution to Natural Gas Production by Basin Adjusted for Canadian and In-State Production, 1990

Basin	Formula[a]	Adjusted Basin Split[b]
Gulf Coast	((41% × 85.2%) + (41% × 12.6%)) =	40.1%
East Texas	((15% × 85.2%) + (15% × 12.6%)) =	14.7%
Anadarko	((22% × 85.2%) + (22% × 12.6%)) =	21.5%
Arkoma	((13% × 85.2%) + (13% × 12.6%)) =	12.7%
Appalachia	((9% × 85.2%) + (9% × 12.6%)) =	8.8%

[a] Formula explanation: (Original basin contribution from Table 10 × Percentage of domestic out-of-state production) + (weighted average of Canadian natural gas).

[b] Total equals 97.8% because 2.2% produced from in-state (NYSERDA 2024).

The NETL model does not characterize conventional extraction of natural gas from Appalachia since many natural gas wells in that region often fail to meet the GHGRP emissions reporting threshold of 25,000 mt CO_2e per year per facility (100-yr IPCC AR4 GWP) (NETL 2019). Given the significance of the Appalachian basin to NYS natural gas consumption, conventional gas production emissions from this basin were assessed using data from the NYSERDA Oil and Gas Methane Inventory (NYSERDA 2024). The default emission factors in the Oil and Gas Methane Inventory reflect the 25th percentile of measured site-level production emissions from conventional wells in southwest Appalachia (Omara et al. 2016).

The team applied the same approach to model natural gas imports to the four regions from which New York State imports electricity: PJM (Pennsylvania, Jersey, Maryland), ISO (Independent System Operators) New England, Ontario, and Quebec. ERG used the same five basins and basin splits, selected a central point for each electricity region's destination for the gas, and adjusted the transmission distance parameter in the NETL model to reflect the distance from the origin city to the destination.

GHG emissions from natural gas systems often appear as a methane emission rate, indicating the emissions of methane per unit of natural gas delivered to the end-consumer. This rate predominantly accounts for the venting or fugitive release of natural gas, with methane as the primary constituent, throughout the supply chain. Figure 5 displays the natural gas system's CH_4 emission rate for basins serving New York State over the time series, while Figure 6 shows the resulting aggregate NYS methane emission rate from out-of-state production as it transmits to the NYS border. Table 12 summarizes the method for applying historical scaling factors to 2016 model results by basin and stage.

Figure 4. Modeled Natural Gas Basins Serving New York State over the Time Series

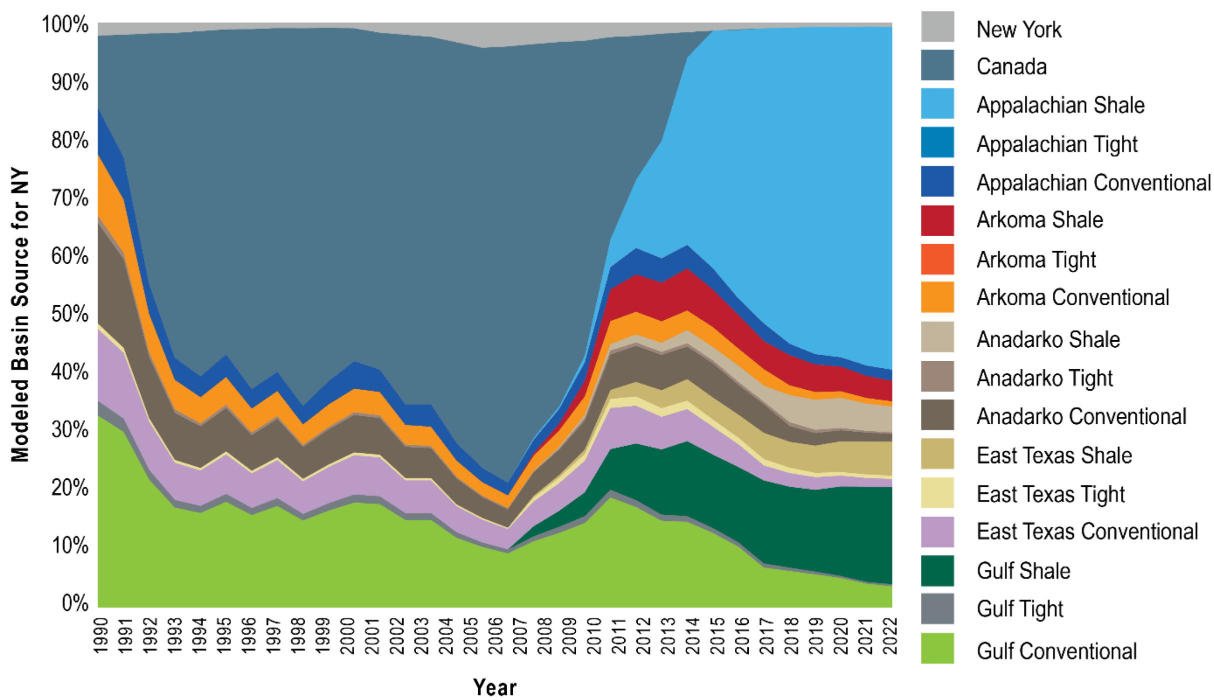


Figure 5. Natural Gas System Methane Emission Rates for Basins Serving New York State

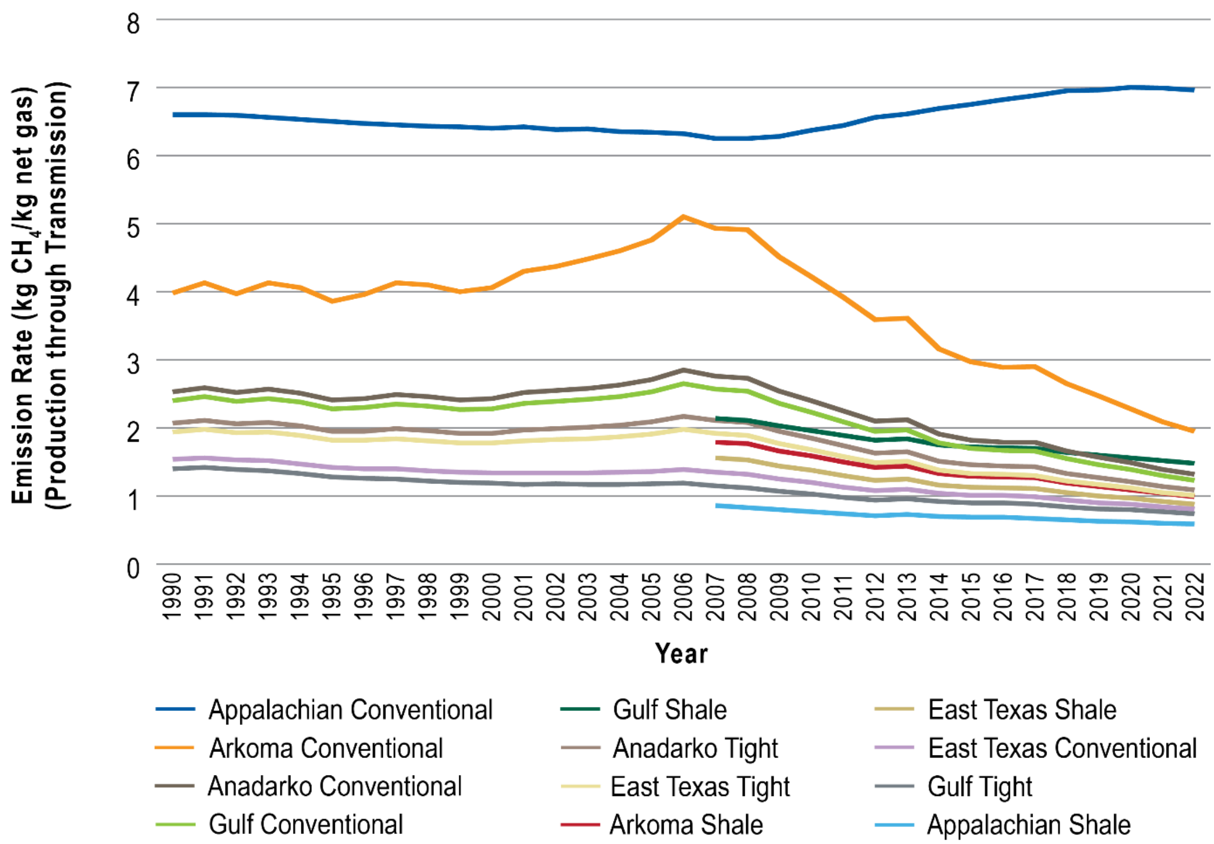


Figure 6. Natural Gas System Weighted Average Methane Emission Rates by Stage

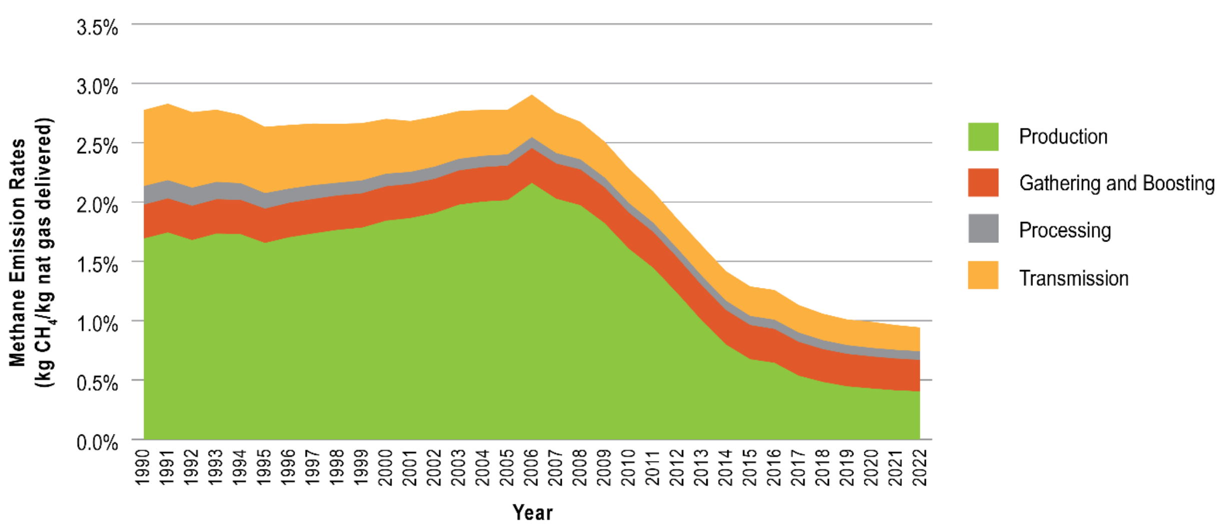


Table 12. Summary of Methane Emissions Rate by Basin and Stage

Basin	Year	Share	Production	Gathering and Boosting	Processing	Transmission	Total[a]
Anadarko Conventional	2016	5%	1.1%	0.3%	0.1%	0.3%	1.8%
Anadarko Shale	2016	3%	0.3%	0.3%	0.1%	0.3%	1.0%
Anadarko Tight	2016	0%	0.7%	0.3%	0.1%	0.3%	1.4%
Appalachian Conventional	2016	3%	6.3%	0.3%	0.1%	0.2%	6.8%
Appalachian Shale	2016	50%	0.1%	0.3%	0.1%	0.2%	0.7%
Arkoma Conventional	2016	3%	2.1%	0.4%	0.1%	0.3%	2.9%
Arkoma Shale	2016	5%	0.5%	0.4%	0.1%	0.3%	1.3%
East Texas Conventional	2016	3%	0.3%	0.3%	0.1%	0.3%	1.0%
East Texas Shale	2016	4%	0.4%	0.3%	0.1%	0.3%	1.1%
East Texas Tight	2016	1%	0.6%	0.3%	0.1%	0.3%	1.3%
Gulf Conventional	2016	7%	1.0%	0.3%	0.1%	0.3%	1.7%
Gulf Shale	2016	14%	1.0%	0.3%	0.1%	0.3%	1.7%
Gulf Tight	2016	1%	0.2%	0.3%	0.1%	0.3%	0.9%
New York State Aggregate	2016		0.6%	0.3%	0.1%	0.3%	1.3%
Historical Scaling Factor (CH_4)[b]	*1990/2016*		*1.32*	*0.77*	*2.89*	*2.51*	
Anadarko Conventional	1990	20%	1.4%	0.3%	0.2%	0.7%	2.5%
Anadarko Shale	1990	0%	N/A	N/A	N/A	N/A	N/A
Anadarko Tight	1990	1%	0.9%	0.3%	0.2%	0.7%	2.1%
Appalachian Conventional	1990	9%	5.7%	0.2%	0.2%	0.5%	6.6%
Appalachian Shale	1990	0%	N/A	N/A	N/A	N/A	N/A
Arkoma Conventional	1990	12%	2.8%	0.4%	0.2%	0.6%	4.0%
Arkoma Shale	1990	0%	N/A	N/A	N/A	N/A	N/A
East Texas Conventional	1990	14%	0.4%	0.3%	0.2%	0.7%	1.5%
East Texas Shale	1990	0%	N/A	N/A	N/A	N/A	N/A
East Texas Tight	1990	1%	0.8%	0.3%	0.2%	0.7%	1.9%
Gulf Conventional	1990	37%	1.3%	0.3%	0.2%	0.7%	2.4%
Gulf Shale	1990	0%	N/A	N/A	N/A	N/A	N/A
Gulf Tight	1990	3%	0.3%	0.3%	0.2%	0.7%	1.4%
New York State Aggregate	1990		1.7%	0.3%	0.2%	0.6%	2.8%

[a] The total may not equal the sum of the values across the row due to rounding.

[b] The historical scaling factor estimates the change in emissions relative to 2016 based on the U.S. GHG Inventory. Results can be approximated by multiplying the historical scaling factor by the CH_4 emissions rate in each basin and weighting by the basin share. The NYS aggregate emissions rate excludes in-state emissions from transmission and distribution as discussed in section 2.1.14.

2.2.1.1 Natural Gas Upstream Sensitivity Analyses

Recent comparisons of results between recent top-down approaches using observations and atmospheric transport models and bottom-up inventories have revealed significant differences in emission estimates. The National Academy of Sciences (NAS) report, “Improving Characterization of Anthropogenic Methane Emissions in the United States” (NAS 2018), highlights these differences, which are important in developing the NYS GHG Inventory. The report emphasizes one of the largest methane source categories identified: petroleum and natural gas systems.

Due to these discrepancies, ERG conducted a targeted literature review on top-down versus bottom-up approaches for the natural gas and petroleum systems categories. Several studies indicate that a strictly bottom-up approach could underestimate GHG emissions. For example, two studies (Miller 2013, Petron 2014) found that top-down methane emission estimates in the petroleum and natural gas categories consistently exceeded bottom-up inventories by 5% to 200% or more (NAS 2018).

Critics of bottom-up approaches also cite uncertainty and inaccuracy surrounding activity data and emission factors, often concerning the U.S. GHG Inventory. NAS (2018) explains that the lack of sufficient activity data for developing emissions estimates represents a significant source of uncertainty in the U.S. GHG Inventory despite including numerous emissions sources from petroleum and natural gas systems. In addition, the U.S. GHG Inventory might underestimate emissions because it does not account for high emissions resulting from abnormal operating conditions (Alvarez et al. 2018). Based on GHG measurements obtained via aircraft observation, Plant et al. (2019) note that current urban inventory estimates of natural gas emissions are substantially low due to underestimating leakage, omitting end-use emissions, or a combination of both. To improve bottom-up approaches, NAS (2018) recommends using finer-scale, geographically gridded inventories of national methane emissions for improved characterization and inventory comparisons and testing against top-down methane estimates.

Several studies advocate for a complementary, hybrid top-down/bottom-up approach to achieve more accurate emission estimates. For example, an Environmental Defense Fund study (Alvarez et al. 2018) integrates results from facility-scale, bottom-up studies to estimate methane emissions from the U.S. oil and natural gas supply chain and then validates these results using methods from top-down studies.

In recent years, shale gas has increasingly contributed to the total gas produced for NYS consumption (Figure 4). In contrast, the contribution from conventional gas has declined over time, leading to low-producing conventional wells. Despite their decreasing output, literature has identified these low-producing wells (known as super-emitters) due to their disproportionately large emissions (Zavala-Araiza et al. 2015, Alvarez et al. 2018, Schneising et al. 2020).

Recognizing the potential for underestimating GHG emissions through a strictly bottom-up approach, ERG adjusted emission factors for the upstream natural gas fuel cycle to incorporate the latest literature, including top-down methods in the natural gas supply chain. These adjustments, detailed below, reflect both a midrange and high-range approach.

The Mid sensitivity approach accounts for the potential impact of super-emitters from the Appalachian Basin while maintaining consistency with the data sources used in the original approach and the NYSERDA Oil and Gas Methane Inventory. To do so, ERG incorporated Omara and colleagues (2016)-derived midpoint emission factors (50th percentile of measured site-level production emissions from conventional wells in Southwest Appalachia). The same approach applies to Appalachian shale gas production to assess the uncertainty around this data point (EDF 2021).

The High sensitivity approach builds on the Mid sensitivity approach, incorporating stage-level scaling factors. Existing literature on natural gas methane emissions has highlighted discrepancies between reported estimates between inventory data and emissions monitoring (Alvarez et al. 2018). Alvarez and colleagues assessed national methane emissions from the U.S. natural gas supply chain, using facility-level estimates and validating these emissions through aircraft observations. Their measurements were about 60% higher than the emissions reported in the U.S. GHG Inventory, suggesting that the Inventory may underestimate methane emissions by not fully accounting for emissions released during abnormal operating conditions. The emission estimate discrepancies Alvarez (2018) identified enabled the adjustment of emission factors for this analysis, integrating stage-level scaling factors (Table 13).

Table 13. Stage-Level Scaling Factors

Source: Alvarez et al. (2018).

Stage	Scaling Factor
Production	2.17
Gathering and boosting	1.13
Processing	1.60
Transmission	1.38

For the production stage, the team applied the Alvarez-derived scaling factor to non-Appalachian basins only, as the Mid sensitivity already addresses the potential underestimation of production emissions from Appalachia. In contrast, the team applied the scaling factors for all subsequent natural gas stages to all basins, including Appalachia.

Table 14 summarizes the parameters ERG incorporated into each of the natural gas approaches (original approach plus two sensitivities; approaches referred to as Low, Mid, and High, respectively), their parameter values, and their effect on the NYS aggregate methane emission rate for natural gas consumed in the State. Table 15 displays the 2022 out-of-state emission rates for each basin across the three approaches.

ERG implemented adjustments to the estimates of methane emissions from natural gas systems to better align this sensitivity analysis with the in-state methane emissions calculations from the NYS Oil and Gas Methane Inventory (NYSERDA 2024). The default inventory in the NYS Oil and Gas Methane Inventory applies an Omara and colleagues (2016)-derived emission factor for conventional natural gas production that reflects the 25th percentile of measured site-level production emissions (Omara et al. 2016). Following the upstream emissions calculations for conventional gas in the Appalachian basin, ERG modified the in-state inventory to use the 50th percentile emission factor from Omara and colleagues (labeled as Mid in that inventory) under the Mid and High sensitivities calculated here.

This sensitivity affects only the emissions from conventional gas production, including both low- and high-producing wells, are impacted by this sensitivity. The team makes no further adjustments to in-state emissions under the High sensitivity (i.e., ERG does not use stage-level scaling factors) to maintain consistency with the available emissions factors within the NYS Oil and Gas Methane Inventory.

Table 14. Summary of Natural Gas Approaches and Parameters, 2022 Values

Parameters	Low Sensitivity	Mid Sensitivity	High Sensitivity	Parameter Notes
NETL Natural Gas Model; Emissions by Technobasin	X	X	X	Gas types: conventional, shale, tight
Addition of Appalachian Conventional Production Emission Rate (Omara et al. 25th percentile)[a]	X			Production emission rate: 6.5%
Addition of Appalachian Conventional Production Emission Rate (Omara 50th percentile)		X	X	Production emission rate: 15.3%
NETL Natural Gas Model Appalachian Shale Production Emission Rate	X			Production emission rate: 0.07%
Revision to Appalachian Shale Production Emission Rate		X	X	Production emission rate: 0.54%
Top-down Scaling Factor			X	Top-down scaling factors [production: 2.17 (+117%); gathering and boosting: 1.13 (+13%); processing: 1.16 (+16%); transmission: 1.38 (+38%)][b]
NYS Aggregate Out-of-state Emission Rate (%)	0.95%	1.38%	1.82%	Representative of production, gathering and boosting, processing, and transmission
NYS Aggregate Well-to-Burner Emission Rate (%)	1.38%	1.88%	2.32%	Includes all stages above as well as in-state production and consumption

[a] The NETL Natural Gas Model does not characterize emissions from Appalachian Conventional production, so the team supplemented it with data from Omara and colleagues.

[b] REG applied top-down scaling factors from production through transmission across all basins and stages, except for Appalachian production. For example, if the original production emission rate is 1.34%, the top-down adjusted rate is 1.34% × 2.17 = 2.91%. This represents a 117% increase compared to the original rate.

Table 15. Out-of-State Emission Rates by Basin across Sensitivities, 2022

Basin	Low Sensitivity	Mid Sensitivity	High Sensitivity
Anadarko Conventional	1.32%	1.32%	2.30%
Anadarko Shale	0.81%	0.81%	1.19%
Anadarko Tight	1.09%	1.09%	1.80%
Appalachian Conventional	6.96%	15.78%	15.93%
Appalachian Shale	0.59%	1.06%	1.20%
Arkoma Conventional	1.95%	1.95%	3.62%
Arkoma Shale	0.99%	0.99%	1.55%
East Texas Conventional	0.81%	0.81%	1.18%
East Texas Shale	0.88%	0.88%	1.35%
East Texas Tight	1.01%	1.01%	1.61%
Gulf Conventional	1.23%	1.23%	2.16%
Gulf Shale	1.48%	1.48%	2.69%
Gulf Tight	0.74%	0.74%	1.09%

Appendix D provides a breakdown of natural gas emission factors at each stage of the well-to-combustion fuel cycle for the Low, Mid, and High natural gas sensitivities. Table 16 summarizes the approach detailed in this section.

Table 16. Summary of Approach for Estimating Upstream Fuel Cycle Emissions for Imported Natural Gas

Activity	Extraction and Processing of Natural Gas
Approach	The NETL natural gas extraction model (NETL 2019), available in the openLCA software, is the starting point and source for activity data and emission across the upstream natural gas supply chain: production, gathering and boosting, processing, transmission, storage, and distribution.[a] The NETL gas model and NYSERDA's Oil and Gas Methane Inventory (NYSERDA 2024) use similar approaches to modeling natural gas production emissions. This inventory integrates empirical data addressing uncertainties in natural gas literature into the NETL model framework to develop regionally specific emission factors. Key uncertainties include emissions from low-producing conventional gas wells (known as super-emitters), shale gas emissions, and discrepancies between bottom-up inventories and top-down measurements. Annex 3.6 of the EPA's GHG Inventory (EPA 2024e) provides emissions scaling factors to account for time-series changes, which are applied to the NETL model and further adjusted during sensitivity analysis.

Table 16. (continued)

Activity	Extraction and Processing of Natural Gas
Source category references	Transportation, electricity, residential, commercial, industrial.
Result	The analysis produced two sets of emission factors for CO_2, CH_4, and N_2O: one for gas used in electricity generation and one for use gas used as fuel by consumers. The inventory excludes emissions from natural gas distribution after transmission because these are captured in the in-state inventory (see section 2.1.14).
Technological scope	The NETL model includes upstream emissions from production to distribution, accounting for blowdowns, flaring, and venting. It also includes emissions from energy inputs into the process, such as emissions from production and consumption of diesel, natural gas, and electricity used during natural gas extraction. End-use combustion emissions are excluded.
Geographic scope	The NETL model reflects emissions from 14 gas-producing regions across the U.S. For gas consumed by NYS from 1990 to 2020, the modeled basins include the Gulf Coast, East Texas, Anadarko, Arkoma, and Appalachian. Basin-specific parameters account for emissions from preprocessing equipment and variations in the chemical composition of the natural gas, which differs between basins and venting or flaring practices. National parameters are applied to postprocessing stages, while NYS-specific transmission data is used to parameterize the model.
Temporal scope	The NETL model reflects 2016 emissions and activities. Major data sources, including the GHGRP and U.S. GHG Inventory, are updated annually, allowing for future model updates. NYSERDA's Oil and Gas Methane Emissions Inventory (NYSERDA 2024) assumes constant emission factors since 1990, with fluctuations in production efficiency due to changing activity data. Although historical data are unavailable in the NETL model, the inventory aligns with NYSERDA's assumption of consistent emission factors and activity data over time. Updated U.S. GHG Inventory data provided emissions and activity data. These data were used to develop emission scaling factors to apply to the model's 2016 values. Adjusted parameters include flaring and venting rates, number of wells, equipment quantities, and energy inputs to the extraction process (e.g., electricity, diesel, and natural gas combustion amounts).
Alternate approaches considered	The GREET model from Argonne National Laboratory includes emission factors for natural gas extraction and processing but lacks basin-specific parameterization and comprehensive coverage of the gas supply chain's emission sources.
Notes	Two sensitivities analyses address discrepancies in national methane emissions from natural gas: 1, Applying the 50th percentile value of measured site-level conventional and shale gas emissions (Omara et al. 2016) to Appalachian production to account for disproportionate releases from super-emitters. 2. The second sensitivity extends top-down scaling factors (Alvarez et al. 2018) to other basins and natural gas stages[a] to reconcile top-down and bottom-up methane emission estimates (Alvarez et al. 2018, Burnham 2022).

[a] Natural gas delivered to consumers accounts for emissions through the distribution stage, whereas this stage is excluded for natural gas used for electricity. While emissions from distribution are analyzed, they are not included in calculations for imported fossil fuels because they are accounted for in the in-state emissions (see section 2.1.14).

2.2.2 Coal Upstream Fuel Cycle

The NETL coal model, which profiles coal extraction through coal cleaning, models conditions for coal production and distribution to New York State for the entire time series (NETL 2020). To account for changes in underground coal mine methane over time, the team applied basin-level scaling factors, as shown in Table 17, using data calculated using the U.S. GHG Inventory (EPA 2019a). The U.S. GHG Inventory developed these estimates using annual data from the Mine Safety and Health Administration and facility-reported data from the GHGRP. These estimates include ventilation emissions, drainage emissions, and avoided emissions from methane capture and use projects. ERG assumed all other mining emission sources remained unchanged. The example calculation in Table 17 was used for years following 1990 and continues to be applied.

Table 17. Underground Coal Mine Methane Scaling Factors

Basin	Underground Mine Methane Emissions (ktons CH_4)		Underground Coal Extracted (Thousand Short Tons)		Scaling Factor, 1990[a]
	1990	2016	1990	2016	
Central Appalachian Basin	1,006	254	198,412	39,800	0.79
Illinois Basin	203	334	69,167	76,578	0.67
Northern Appalachian Basin	952	757	103,865	94,685	1.15
Western Interior Basins	0	20	105	420	—
Black Warrior Basin	577	192	17,531	7,434	1.27
Western Basins	230	71	34,476	33,189	3.11
National	2,968	1,629	423,556	252,106	1.09

[a] Scaling factor calculation: (1990 emissions/1990 production)/(2016 emissions/2016 production).

To determine the source basins and the amount of coal sourced from each basin each year, the team used EIA Form 923 and Federal Energy Regulatory Commission (FERC) Form 423 (EIA 2024e, FERC 2011). These forms specify the amount of coal NYS power plants received and the coal mine condition and type. Using the coal amounts reported for each state, the team calculated a proportional contribution from each basin and then ran the NETL coal model for relevant basins to produce emission factors.

While the NETL coal model accounts for coal production, it does not model coal transport. To model the coal transport from each relevant coal-producing state to New York State, the team used data from EIA's *Annual Coal Distribution Report* (EIA 2023c). The report specifies the amount of coal delivered to the State from each state and the specific mode of transportation used. Using this information, the team calculated a yearly percentage for each transport mode and applied it to the utility data from FERC-423 and EIA-923. Table 18 shows a breakdown of coal transported by mode to New York State in 1990. ERG applied the same method to all years in the time series.

Table 18. Coal Transport by Mode to New York State, 1990

State of Origin	Quantity (Short Tons)[a]	% Transport via Truck[b]	% Transport via Rail[b]	% Transport via River Barge[b]	% Transport via Great Lakes Barge[b]
Kentucky	659,041	6%	94%	0%	0%
Maryland	26,000	0%	100%	0%	0%
Ohio	59,100	82%	0%	18%	0%
Pennsylvania	5,413,460	7%	69%	21%	3%
West Virginia	4,410,692	0%	99%	1%	0%

[a] Based on 1990 FERC coal distribution data.

[b] Based on EIA coal distribution data.

In modeling transport distances, the team made several underlying assumptions, such as identifying points of origin and destination. Coal is transported by land (rail or truck) or water transport (river or the Great Lakes). The team selected Buffalo as the destination point for Great Lakes transport, and New York City was used as the destination for land transport. For river transport, ERG modeled the journey to stop at the NYS–Pennsylvania border north of Pittsburgh to exclude in-state transportation emissions. Table 19 shows each state's point of origin for coal transport in 1990 and the distance to its destination. ERG applied the same NYS boundaries for future years in the time series.

Table 19. Coal Transportation Distances

Destination	Origin Location				
	Pikeville, KY	Cumberland, MD	Ohio	Pennsylvania	Charleston, WV
NY–PA border north of Pittsburgh (river)	NA	NA	530 mi (from Cincinnati)	130 mi (from Pittsburgh)	410 mi
Buffalo (Great Lakes)	NA	NA	NA	80 mi |(from Erie)	NA
New York City (truck)	640 mi	NA	460 mi (from Cambridge)	370 mi (from Pittsburgh)	530 mi
New York City (rail)	520 mi	260 mi	NA	315 mi (from Pittsburgh)	450 mi

ERG derived emission factors for coal transportation from NETL's coal Excel model. This model provides emissions data for the listed transportation modes listed in Table 19 based on diesel consumption over a specified distance. To match the distances in Table 19, the team adjusted the diesel consumption parameter accordingly.

The team applied the same approach to model coal imports to the four regions from which New York State imports electricity: PJM, ISO NE, Ontario, and Quebec. Since PJM and ISO NE encompass several states, the team calculated a weighted average of coal deliveries to power plants in each state to determine the basin-specific coal amounts. The team sourced coal delivery and transport to power plants mode data from FERC Form 423 and the EIA's *Annual Coal Distribution Report,* respectively.

In addition to sourcing coal domestically, some regions also source coal internationally. Because the NETL coal model profiles only U.S. coal basins, ERG used methane emissions for internationally sourced coal from Appendix B-3 of the EPA's *Global Non-CO_2 GHG Emissions: 1990–2030* (EPA 2012). The team then divided these emissions by the total coal produced nationally (IEA 2023) for the respective year to determine an emission factor, which the team assumed represented underground coal. For surface coal mines, ERG modeled methane emissions as equal to the U.S. national average, along with surface and underground carbon dioxide and nitrous oxide emissions.

Appendix D provides a breakdown of coal emission factors at each stage of the well-to-combustion fuel cycle. Table 20 summarizes the approach detailed in this section.

Table 20. Approach for Estimating Upstream Fuel Cycle Emissions for Imported Coal

Activity	Extraction and Processing of Coal
Approach	The NETL coal extraction and processing model available in the openLCA software (NETL 2018) was used as a source for coal emission factors. The model includes emissions from combustion processes during mining and processing and fugitive coal mine CH_4 emissions. Infrastructure impacts are excluded.
Source category references	Electricity, industrial, residential, commercial.
Result	Emission factors for CO_2, CH_4, and N_2O are provided for the relevant coal basins and types consumed in NYS.
Technological scope	The model accounts for the weighted average mix of cleaned and uncleaned coal during processing. It also includes the distribution of coal to power plants, considering transportation distance and mode.
Geographic scope	The model reflects emissions from 10 coal mine basins across the U.S. Data from FERC Form 423 (FERC 2011) and EIA Form 923 (EIA 2024e) are used to identify the state of origin for coal consumed by utilities back to 1990. These data determine the appropriate basin and coal type consumed and are assumed consistent across all source categories because coal consumption data by sector are unavailable before 2001. EIA's *Annual Coal Distribution Report* provides data on coal transport modes from 2001 (EIA 2023c), which are applied to production values across the time series.
Temporal scope	EIA data for coal consumption by sector are available from 2001 onward. The NETL Coal model does not include historical emissions data from coal mining. Coal mine CH_4 is the largest GHG contributor to upstream coal emissions. The U.S. GHG Inventory tracks underground coal mine CH_4 emissions by basin and creates an annual adjustment factor based on coal output.
Alternate approaches considered	The GREET model includes emission factors for the extraction and processing of coal, but it does not account for differences across mine basins or types.

2.2.3 Petroleum Upstream Fuel Cycle

Upstream petroleum fuel cycle emission factors and data on the domestic and international share of crude oil (Table 21) come from Argonne National Laboratory's greenhouse gases, regulated emissions, and energy use in transportation (GREET) Model 2023 (Argonne National Laboratory 2022). The modeling applies GREET's default time series data to reflect the changing share of conventional oil in the U.S. Conventional oil remains the largest source of petroleum production throughout the time series, even with the introduction of oil sands in 2000 and shale oil in 2013.

Table 21. Source of Crude at U.S. Refineries, 2019–2022

Year	2019	2020	2021	2022
U.S. domestic	74.9%	80.2%	77.5%	80.8%
Canada (oil sands)	6.5%	7.2%	7.9%	6.6%
Canada (conventional crude)	7.6%	4.9%	5.9%	5.0%
Mexico	2.2%	2.2%	2.1%	1.9%
Middle East	3.2%	2.4%	2.0%	2.3%
Latin America	3.0%	2.0%	1.9%	1.9%
Africa	1.4%	0.5%	1.1%	0.9%
Others	1.2%	0.6%	1.5%	0.6%

ERG applied emissions from crude extraction and transport in GREET to petroleum products using the loss factor for each product, which reflects the energy ratio of crude inputs to each product.

The underlying emissions for motor gasoline are based on gasoline blendstock in GREET, representing the stream of gasoline blendstock before mixing with blending components such as ethanol. MOVES provides the ethanol content of gasoline in New York State. Since 2014, diesel emissions reflect a 5% reduction due to biodiesel content. Emissions for E85 account for 26% of motor gasoline emissions, based on the energy content of gasoline within E85. Source data for these assumptions align with the modeling performed for transportation (see section 2.1.5 for on-road motor vehicles).

GREET does not include data for waxes and lubricants. Sun and colleagues (2019) provide emission characterizations for refinery products at U.S. refineries, which are used to scale refining emissions for waxes and lubricants based on GREET data for residual oil.

The team modified transportation and distribution parameters in GREET to reflect NYS-specific data. Annual petroleum import data via tanker and Canadian pipeline come from EIA's company-level imports archives (EIA 2023d, 2023e), while data on domestic interstate petroleum movement are sourced from EIA's Movement by Pipeline and Refinery and Blender Net Production datasets (EIA 2023d, 2023f). Total pipeline quantities to New York State reflect the pipeline capacity of the Colonial, Sun, and Buckeye pipelines (ICF 2012). Quantities assumed from the Petroleum Administration for

Defense District (PADD) 3 are based on the share of net receipts by pipeline to PADD 1 (where New York State is located), relative to total PADD 1 production, with the remainder assumed to come from within PADD 1. Barge transport data from PADD 3 comes from EIA's *Movements by Tanker and Barge* (EIA 2023e). NYSERDA reports tanker or barge receipts to New York State for 2005 (Rosenberg and Janney 2006), and the share to the State relative to the rest of PADD 1B is assumed constant across the time series.

Table 22 provides a breakdown of petroleum products transported by mode from each region to New York State in 1990. The same method applies to all other years in the time series.

Table 22. Share and Distance for Transportation of Petroleum Products to New York State, 1990

	Pipeline PADD 3[a]	Pipeline PADD 1[b]	Pipeline Canada[c]	Barge PADD 3[d]	Tanker Africa & Middle East[e]	Tanker Caribbean[f]
Share	40.6%	29.9%	2.0%	0.5%	11.8%	15.2%
Distance (mi)	1410	40	2000	2200	4920	2125

[a] Assumed transport from Houston, TX, to New York City.
[b] Assumed transport from Trenton, NJ, to New York City.
[c] Assumed transport from Fort McMurray, AB, Canada, to New York City.
[d] Assumed transport from Houston, TX, to New York City.
[e] Assumed transport from Tripoli, Libya, to New York City.
[f] Assumed transport from Caracas, Venezuela, to New York City.

The team applied the volume-weighted average distances and total share of each transportation mode in GREET to all petroleum products. Emissions from local distribution via truck transport from bulk terminals are included in the fuel combustion data of this inventory (see section 2.1.5 for on-road motor vehicles). Transportation parameters for this portion are set to zero in GREET.

Additional transportation and distribution assumptions of petroleum products used for imported electricity include:

- Pipeline distribution covers all petroleum products in Quebec and Ontario
- Barge receipts to PJM from PADD 3 cover the portion of PADD 1B receipts not allocated to New York State
- Remaining apparent consumption for PJM, not supplied by international imports or PADD 3 barge receipts, is assumed to come from PADD 1 or PADD 3 pipelines

- Barge receipts to ISO NE from PADD 3 reflect net movements to PADD 1A (EIA 2023e)
- Remaining apparent consumption for ISO NE, not supplied by international imports or PADD 3 barge receipts, is assumed to come by barge from PADD 1B (ICF 2016)

Appendix D provides a breakdown of gasoline and distillate emission factors for each stage of the well-to-combustion fuel cycle. Table 23 summarizes the approach detailed in this section.

Table 23. Approach for Estimating Upstream Fuel Cycle Emissions for Imported Petroleum Products

Activity	Extraction and Processing of Petroleum Products
Approach	The GREET model produces emission factors for petroleum products. It tracks emissions from crude oil extraction, transport to refineries, refining into petroleum products, and distribution. It also accounts for emissions from energy production and energy consumed during these processes. The model excludes infrastructure emissions.
Sector references	Transportation, aviation, commercial, residential, industrial, electricity
Result	The analysis provides emission factors (CO_2, CH_4, and N_2O) for petroleum products refined in the U.S., specifically conventional diesel, gasoline blendstock, residual oil, and kerosene. The analysis excludes quantities of blended ethanol, biodiesel, or any other bio-based blendstocks, which may be included in future inventory iterations incorporating bio-based fuels.
Technological scope	The GREET model estimates emissions from crude oil extraction using a weighted average approach based on conventional crude and shale oil energy content. It bases venting and flaring emissions on the U.S. GHG Inventory, separating them for oil and natural gas (Cai 2018). The model incorporates average transportation distances and modes for imported crudes and petroleum product distribution within the U.S. It allocates emissions from crude oil extraction and transport to refinery products based on individual refinery processes.
Geographic scope	According to EIA data, PADD 3 refineries produce the largest share of petroleum products sent to PADD 1 (including NYS) and contribute the most to U.S. production (EIA 2023f, EIA 2023g). Due to this mix, a national model for extracting and refining imported petroleum products is sufficient. The GREET model reflects the foreign and domestic crude oil mix used by U.S. refineries and retains the default transportation parameters for crude oil. Transportation of petroleum products to NYS uses GREET modules to estimate transportation mode and distance based on reported movements between PADDs and imports from foreign countries.

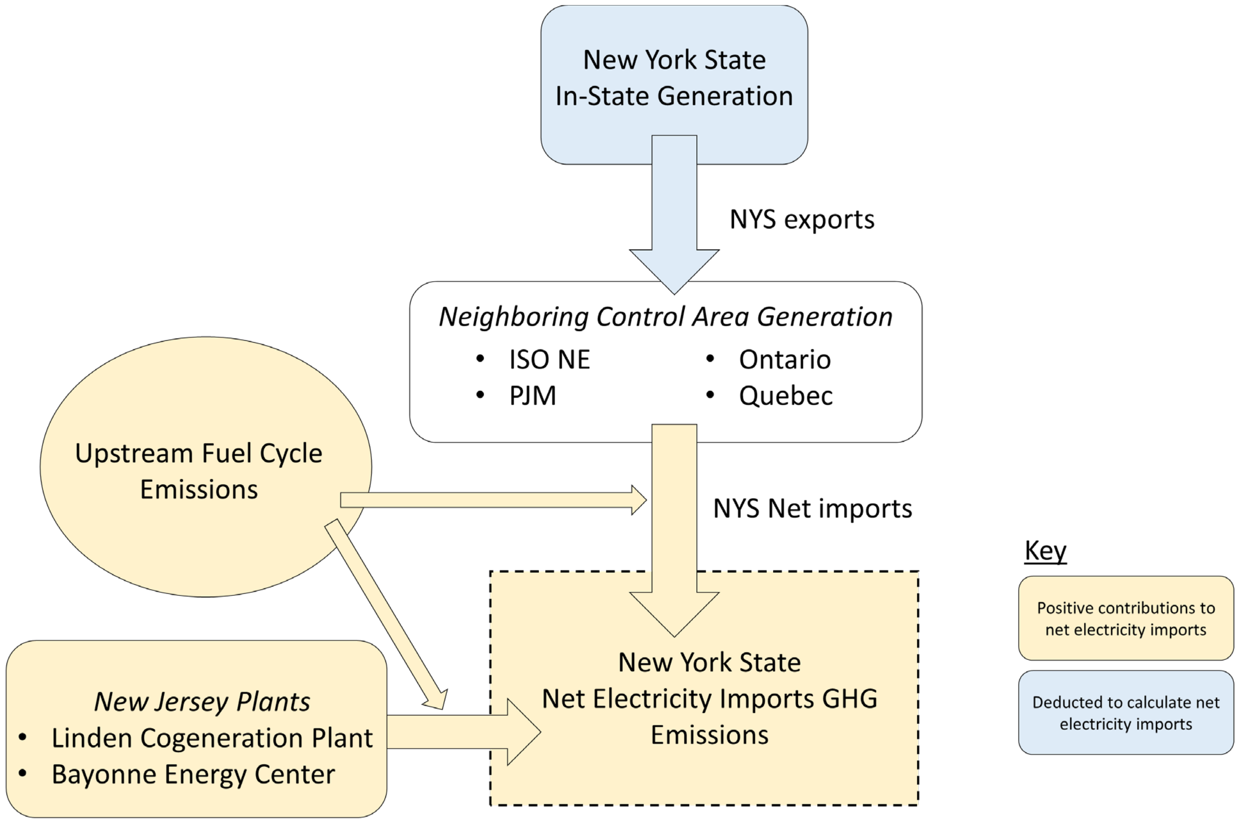
Table 23. (continued)

Activity	Extraction and Processing of Petroleum Products
Temporal scope	GREET includes time series data (some extending back to 1990) for tracking emissions over time. Key adjusted parameters in the petroleum products supply chain include: • Crude oil sources • Combustion emission factors (e.g., industrial boilers) • Refinery efficiency • National electricity mix
Alternate approaches considered	OPGEE and PRELIM (Brandt 2018, Bergerson 2021) require extensive unavailable input data for the crude assays consumed in NYS. These models were leveraged in developing GREET. The EPA Oil and Gas Estimation Tool (EPA 2015) uses county-level activity data for criteria air pollutant emissions but lacks sufficient granularity for imported petroleum fuels without detailed activity location data.

2.3 Energy (Imported Electricity)

To estimate GHG emissions from imported electricity, the methodology involves calculating net electricity imports to New York State from each neighboring region by subtracting gross electricity exports from gross imports into the State. Emission factors specific to each region's GHG emissions intensity are applied to the net imports from that region. Upstream fuel cycle emissions associated with net electricity imports are estimated by multiplying fuel-specific upstream emission factors by net electricity imports (Figure 7). This section details each calculation step, including adjustments made across the time series to account for variations in data availability. The approach used to estimate emissions for imported electricity is divided into two periods based on data availability: 1990–2004 and 2005–present.

Figure 7. Boundaries of Net Electricity Imports Greenhouse Gas Emissions in New York State



2.3.1 Net Electricity Imports

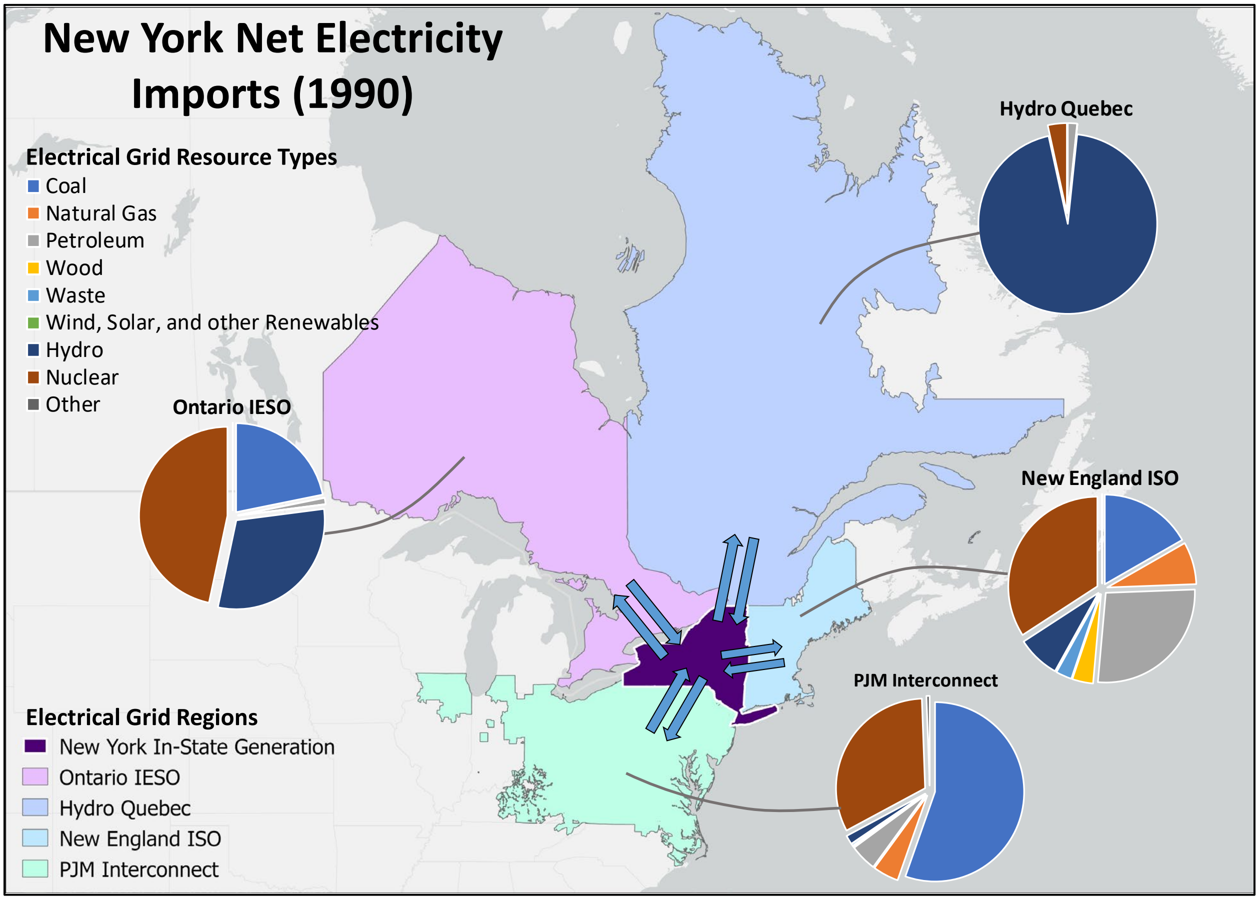
For 1990–2004, data for NYS generation and total system demand are sourced from EIA and New York Independent System Operator (NYISO) Gold Book, respectively (NYISO 2023a). Net imports are calculated by subtracting in-state generation from total system demand. The generation mix for each U.S.-based importing region is determined using fuel-specific generation quantities by state from EIA (EIA 2024e). For Canadian imports, the generation mix is sourced from Canada's National Emissions Inventory (Environment and Climate Change Canada 2023). As an example, Figure 8 shows the 1990 resource mix profiles and regions. Since no data are available for the regional share of electricity imported into New York State during this period, analysts assume that the regional shares of electricity in 1990–2004 are proportional to the regional share of electricity imports observed in 2005–2009.

For 2005–present, imported energy is calculated using reported interface data from NYISO (NYISO 2024b). Hourly net import data series are tabulated for the four surrounding regions: PJM, ISO NE, Quebec, and Ontario. These data are calibrated with sources such as the Regional Greenhouse Gas Initiative report and import data from neighboring ISOs, aligning with the methodology used in the "Patterns and Trends: New York State Energy Profile" (NYSERDA 2022) calculations for this period.

When NYISO is a net exporter of energy to a neighboring power control region, the applied emission factor is assumed to be zero metric tons per megawatt hour. This ensures that all emissions produced in New York State are counted in the State's inventory.

Two New Jersey power plants directly connected to NYISO supply power to New York State: the 974-megawatt (MW) Linden Cogeneration Plant (Linden, NJ) and the 644-MW Bayonne Energy Center (Bayonne, NJ). Emissions from these plants are tracked separately using EPA Air Markets Program data, and this inventory associates them with net electricity imports. These emissions are explicitly identified, allowing future inventories to associate them with in-state emissions if needed. Neither plant was operational in the 1990 baseline inventory year.

Figure 8. New York State Imported Electricity, 1990: Resource Mix Profiles and Regions



2.3.2 Direct Emissions from Net Electricity Imports

Emission factors for generating electricity in each source region are calculated by fuel type, where possible, and multiplied by each region's import quantity to determine total emissions. Emission factors for each region are estimated as follows:

- 1990–2004: PJM and ISO NE emissions are calculated by dividing EIA state-specific CO_2 emissions data by total state generation data. (For this period, PJM includes Delaware, Maryland, New Jersey, Pennsylvania, and Washington, D.C. ISO New England includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.) Methane and N_2O emission factors are estimated using IPCC AR5 fuel-specific factors (Myhre et al. 2013) applied to regional fuel consumption, with biogenic emissions calculated separately. Emissions and generation associated with the New Jersey plants but electrically connected to New York State are subtracted.

- 2005–present: Regional, generation and emissions data from the Regional Greenhouse Gas Initiative, EIA, EPA, and PJM Generation Attribute Tracking System (EIS 2023) are used to calculate CO_2 factors. For CH_4, N_2O, and biogenic emissions factors are derived using EIA fuel consumption data and generation data from PJM and ISO New England. This step begins earlier for some regions (ISO New England data are first available in 2000 and PJM data in 2004.)
- For the New Jersey plants electrically connected to NYISO, CO_2 emissions are estimated using EPA Air Markets data. SEDS data (EIA 2024f) on fuel consumption are used to apply the same fuel-specific, IPCC-derived CH_4 and N_2O emission factors discussed above, determining plant-specific non-CO_2 GHG emissions.
- For Canadian imports, emission factors are based on Canada's National Emissions Inventory (Environment and Climate Change Canada 2023) for Ontario and Quebec. Factors for 1990, 2000, 2005, and 2012–present are reported. For all missing years, CO_2, CH_4, and N_2O emission factors are interpolated.

2.3.3 Upstream Fuel Cycle Emissions for Net Electricity Imports

Upstream fuel cycle emissions are included for fuels consumed in generating net electricity imports. The methodology aligns with the approach for in-state fuel consumption but incorporates adjustments for transportation and distribution specific to each generating region. Section 2.2 provides relevant details for each fuel type.

3 Results

The following section presents the NYS 1990–2022 energy sector GHG Inventory results. Appendix F provides the full table of results. Unless otherwise specified, the results shown reflect AR5 20-year GWP, include biogenic CO_2 emissions, reflect the High natural gas upstream emission factor calculation approach discussed in section 2.2.1.1, and show hybrid transportation assumptions. Appendix G provides additional sensitivities for these settings.

3.1 Time Series Findings

Figure 9 and Table 24 show total energy emissions from 1990 to the present, broken out by emissions from in-state and out-of-state sources. In-state emissions include all in-state fuel combustion and all emissions from in-state oil and gas production. Out-of-state emissions include all net electricity imports and upstream fuel cycle emissions. Total energy sector emissions were 297 MMT CO_2e in 2022. Emissions per capita peaked in 2000 but have since fallen to a low of 13.1 MTCO_2e per person in 2020 before rebounding to 15.1 MT CO_2e per person in 2022 (OpenNY 2024). In-state emissions of CO_2 contributed 64.8% (192.7 MMT CO_2e) to total GHGs in 2022.

Figure 9. Total In-State and Out-of-State Energy per Capita Emissions and Greenhouse Gas Makeup for New York State, 2022

Values in MMT CO_2e.

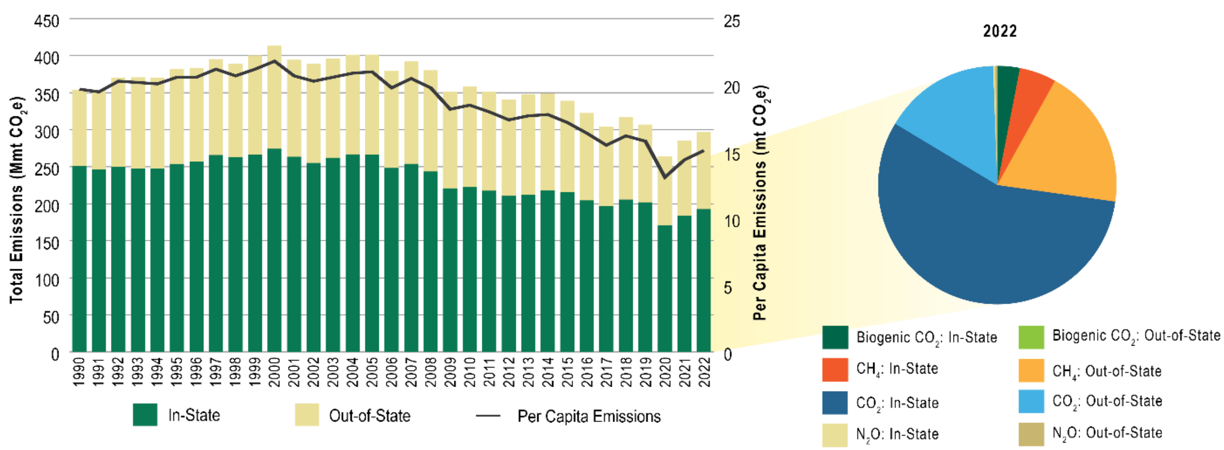


Table 24. Total In-State and Out-of-State Energy Emissions for New York State

Values in MMT CO_2e.

Emission Category	1990	2000	2010	2015	2019	2020	2021	2022
In-state	251.3	274.2	222.5	215.7	201.9	170.9	183.9	192.7
Out-of-state	102.7	139.1	135.8	123.2	105	93.4	101.1	104.3
Total	354	413.3	358.3	338.9	306.9	264.3	285	297

3.2 Results by Fuel

Figure 10 and Table 25 show total NYS energy sector GHG emissions by fuel type, from in-state and out-of-state contributions. Emissions from producing and using petroleum and natural gas products resulted in 287 MMT CO_2e in 2022. In 2022, in-state petroleum product emissions were the largest contributor to total emissions at 97.6 MMT CO_2e, followed closely by in-state natural gas combustion and fugitive emissions at 88.1 MMT CO_2e. Out-of-state natural gas production and transmission was the third-largest contributor to total emissions at 67.9 MMT CO_2e. Out-of-state petroleum product emissions emission totaled 33.1 MMT CO_2e.

Figure 10. Total In-State and Out-of-State Energy Emissions by Fuel Group for New York State

Values in MMT CO_2e.

- Biomass: Wood
- Coal Products: Coal; Coal—Coking; Coal—Other
- Natural Gas Products: Natural Gas; CNG
- Petroleum Products: Distillate Fuel; Petroleum Coke; Residual Fuel; Kerosene; LPG; Asphalt and Road Oil; Lubricants; Miscellaneous Petroleum Products; Special Naphthas; Waxes; Lubricants (Transportation); Gasoline; Diesel; E85; Aviation Gasoline; Jet Fuel

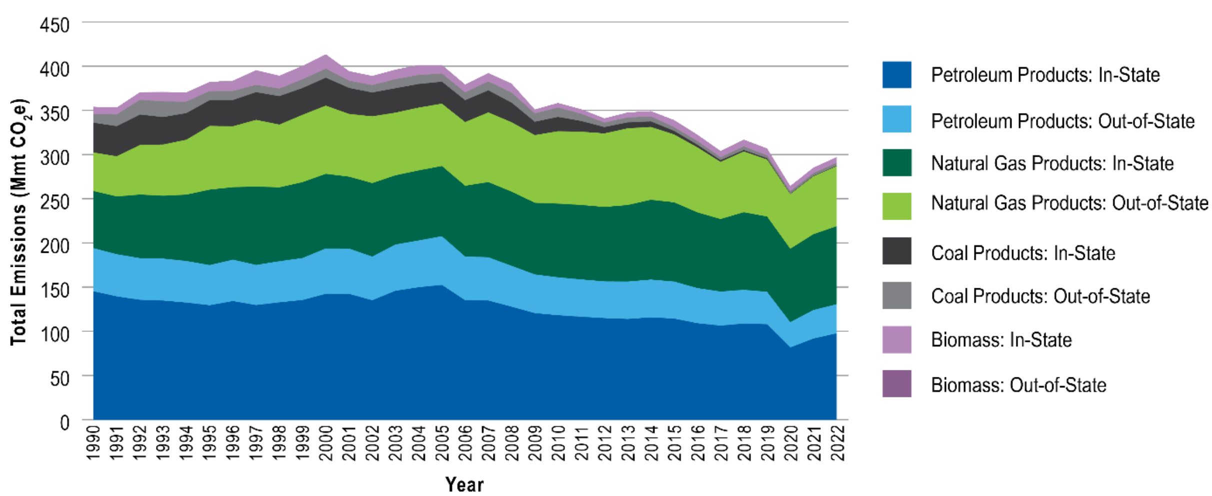


Table 25. Total In-State and Out-of-State Energy Emissions by Fuel Group for New York State

Values in MMT CO_2e.

Fuel, Context[a]	1990[a, b]	2000	2010	2015	2019	2020	2021	2022
Petroleum Products, In-state	145.2	142.2	118.1	114.3	107.9	81.6	91.7	97.6
Petroleum Products, Out-of-state	49.0	51.5	43.1	42.1	36.9	28.8	32.5	33.1
Natural Gas Products, In-state	64.4	84.2	83.2	89.5	84.9	82.8	85.6	88.1
Natural Gas Products, Out-of-state	43.7	77.3	82.0	76.9	64.7	61.9	65.7	67.9
Coal Products, In-state	33.6	31.5	16.1	3.9	1.3	0.6	0.5	0.6
Coal Products, Out-of-state	10.0	10.2	10.7	4.2	3.4	2.7	3.0	3.3
Biomass, In-state	8.1	16.2	5.1	8.0	7.7	5.9	6.1	6.4
Biomass, Out-of-state	—	0.1	0.1	—	—	—	—	—
Total	354.0	413.2	358.4	338.9	306.8	264.3	285.1	297.0

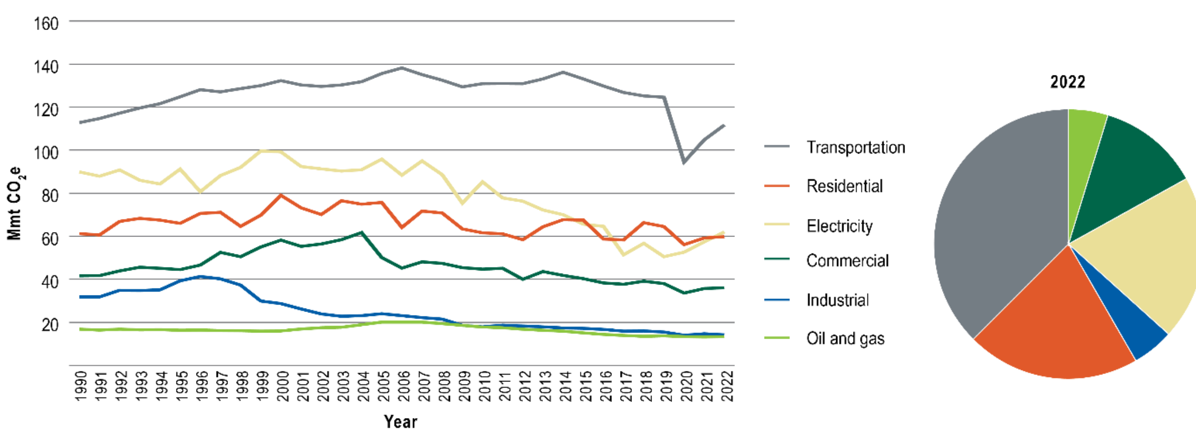
[a] A dash (—) indicates no reported emissions.

3.3 Results by Sector

Figure 11 illustrates the energy emissions by sector. Combustion and upstream emissions for the transportation sector remain the largest source of energy sector emissions in the State in 2022.

Figure 11. New York State Energy Emissions by Sector

Values in MMT CO_2e.



3.3.1 Residential Sector

Figure 12 and Table 26 show emissions generated from fuel consumption by the residential sector. The largest contributors to total residential sector emissions in 2022 were from in-state (24.8 MMT CO_2e) and out-of-state (19.0 MMT CO_2e) natural gas consumption.

Figure 12. New York State Residential Sector Energy Emissions by Fuel

Values in MMT CO_2e.

- Other: Coal; Kerosene; LPG

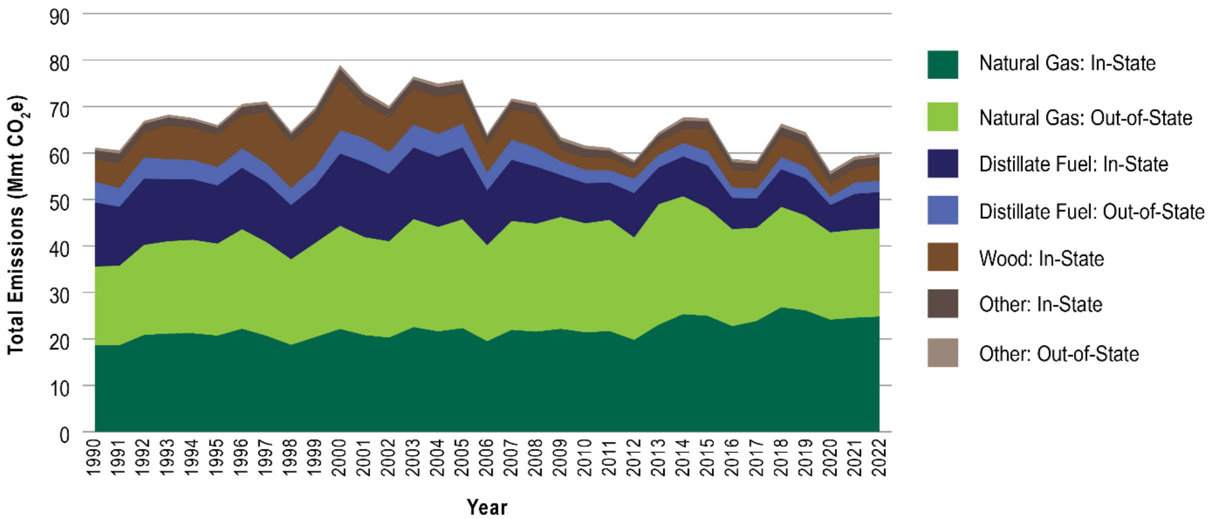


Table 26. New York State Residential Sector Energy Emissions by Fuel Group and Context

Values in MMT CO_2e.

Fuel, Context	1990	2000	2010	2015	2019	2020	2021	2022
Distillate Fuel, In-state	13.8	15.5	8.6	9.2	7.9	5.8	7.7	7.8
Distillate Fuel, Out-of-state	4.4	5.0	2.9	3.1	2.5	1.8	2.5	2.4
Natural Gas, In-state	18.6	22.1	21.4	24.9	26.1	24.1	24.5	24.8
Natural Gas, Out-of-state	17.0	22.2	23.5	23.2	20.4	18.8	18.9	19.0
Wood, In-state	5.0	10.8	2.7	4.8	4.6	2.9	3.1	3.4
Other, In-state	1.8	2.4	1.8	1.6	2.0	1.9	1.8	1.7
Other, Out-of-state	0.6	0.9	0.7	0.7	0.8	0.7	0.7	0.7
Total	61.2	78.9	61.6	67.5	64.3	56.0	59.2	59.8

3.3.2 Commercial Sector

Figure 13 and Table 27 display commercial sector energy emissions by fuel and by in-state and out-of-state categories. Like the residential sector, both in-state (16.7 MMT CO_2e) and out-of-state (12.8 MMT CO_2e) natural gas emissions were the largest contributors to total emissions in the commercial sector from 1990 to 2022.

Figure 13. New York State Commercial Sector Energy Emissions by Fuel

Values in MMT CO_2e.

- Other: Coal; Kerosene; LPG; Wood

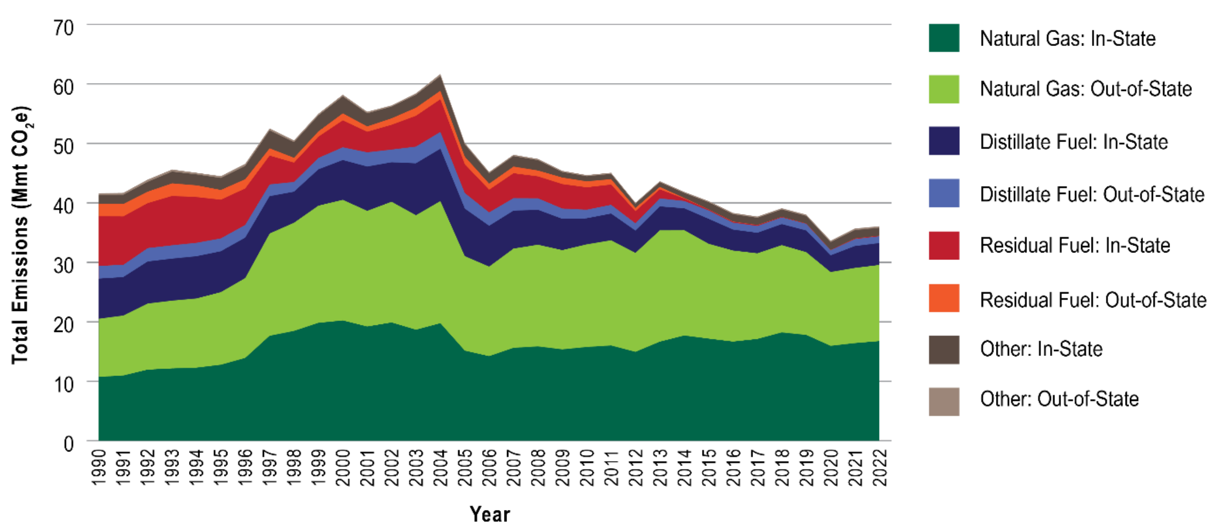


Table 27. New York State Commercial Sector Energy Emissions by Fuel Group and Context

Values in MMT CO_2e.

Fuel, Context[a]	1990	2000	2010	2015[b]	2019	2020	2021	2022
Distillate Fuel, In-state	6.7	6.7	4.4	4.2	3.6	2.8	3.7	3.7
Distillate Fuel, Out-of-state	2.2	2.2	1.5	1.4	1.1	0.9	1.2	1.1
Natural Gas, In-state	10.7	20.2	15.8	17.2	17.8	15.9	16.4	16.7
Natural Gas, Out-of-state	9.8	20.3	17.3	16.0	13.9	12.4	12.7	12.8
Residual Fuel, In-state	8.3	4.5	3.8	0.1	0.1	—	0.1	0.1
Residual Fuel, Out-of-state	2.1	1.2	1.0	—	—	—	—	—
Other, In-state	1.4	2.8	0.8	1.2	1.2	1.3	1.4	1.3
Other, Out-of-state	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3
Total	41.6	58.2	44.7	40.3	38.0	33.6	35.7	36.1

[a] A dash (—) indicates no reported emissions.

3.3.3 Electricity Sector

Figure 14 and Table 28 illustrate trends in electricity sector emissions by fuel type, including electricity imports in the out-of-state fuel emissions categories. Table 28 also provides aggregated emissions for all fuels: in-state combustion, out-of-state upstream, and imported electricity emissions. Between 1990 and 2022, electricity emissions from coal and petroleum declined as natural gas use increased. In 1990, natural gas accounted for 27% (24.2 MMT CO_2e) of total electricity sector emissions. By 2022, natural gas accounted for 91% (56.6 MMT CO_2e). Figure 15 shows the electricity generation mix for electricity produced in New York State and illustrates the growth of natural gas use in the sector since the early 2000s (EIA 2024e). After the closure of the final nuclear reactor at Indian Point Energy Center in 2021, in-state natural gas consumption for electricity peaked high in 2022, and emissions from natural gas reached their highest levels since 2016. The reduction in in-state generation in 2022 continues to be offset by increased imported electricity from PJM.

Figure 14. New York State Electricity Sector Energy Emissions by Fuel

Values in MMT CO_2e.

- Petroleum Products: Distillate Fuel; Petroleum Coke; Residual Fuel

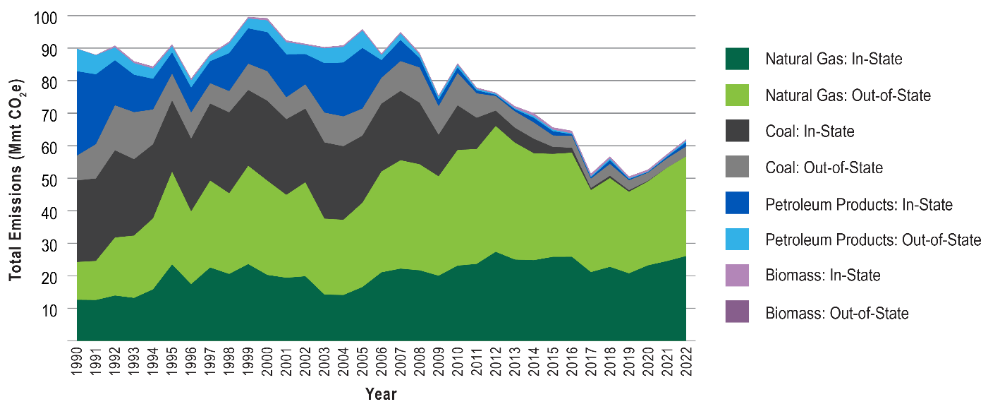


Table 28. New York State Electricity Sector Energy Emissions by Fuel Group and Context

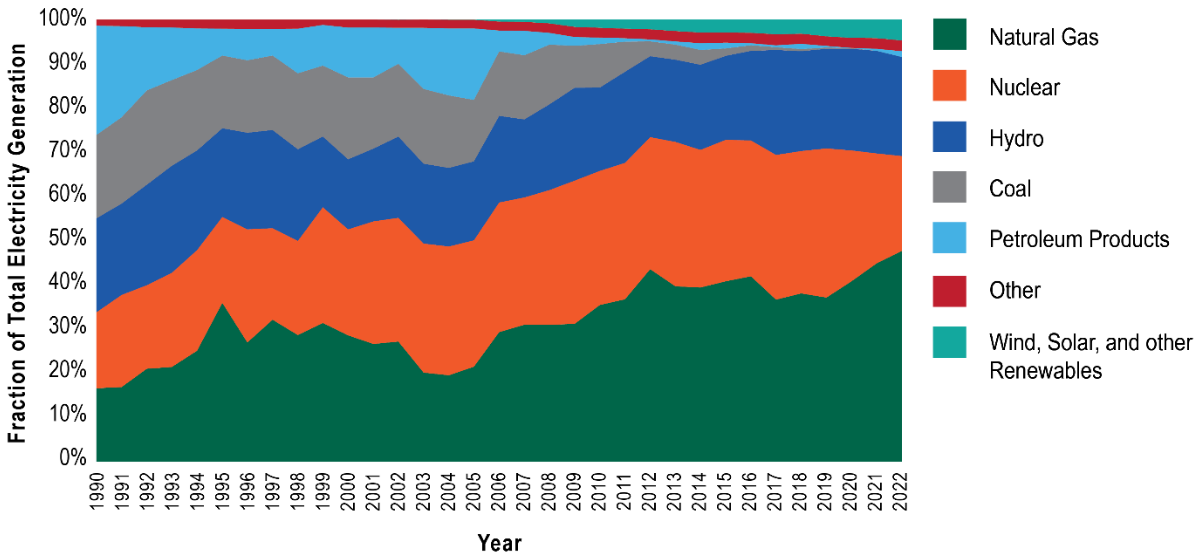
Values in MMT CO_2e.

Fuel, Context[a]	1990[a]	2000	2010	2015[b]	2019	2020	2021	2022
Coal, In-state	25.0	24.5	13.7	2.1	0.5	0.2	-	-
Coal, Out-of-state	7.7	9.1	10.0	3.6	3.1	2.5	2.8	3.1
Petroleum Products, In-state	25.9	12.0	1.7	1.3	0.3	0.2	0.5	1.2
Petroleum Products, Out-of-state	6.9	3.6	0.8	0.5	0.2	0.2	0.3	0.5
Natural Gas, In-state	12.6	20.2	23.1	25.8	20.7	23.2	24.5	26.0
Natural Gas, Out-of-state	11.6	29.0	35.6	31.7	25.1	25.8	28.7	30.6
Biomass, In-state	0.1	0.6	0.4	0.7	0.6	0.6	0.6	0.5
Biomass, Out-of-state	0.0	0.1	0.1	—	—	—	—	0.0
Total	89.9	99.2	85.3	65.6	50.5	52.6	57.4	62.0
Source								
All Fuels, In-state, Combustion	63.6	57.3	38.9	29.9	22.1	24.1	25.6	27.8
All Fuels, Out-of-state Upstream	25.3	32.9	36.0	29.2	20.6	22.0	23.4	25.5
Imported Electricity	0.9	9.0	10.5	6.6	7.8	6.5	8.4	8.7

[a] A dash (—) indicates no reported emissions.

Figure 15. New York State In-State Electricity Generation Mix

- Petroleum Products: Distillate Fuel Oil; Petroleum Coke; Residual Fuel Oil
- Other: Wood; Waste; Other



3.3.4 Industrial Sector

Figure 16 and Table 29 show total energy emissions by fuel in the industrial sector. Natural gas consumption was the largest source of industrial sector emissions, representing 58.7% (8.4 MMT CO_2e) of total industrial emissions in 2022. Natural gas contributed more in 2022 than in 2021 because the contributions of other fuels have decreased overall. As a result, the total GHG emissions for the industrial sector were slightly lower in 2022.

Figure 16. New York State Industrial Sector Energy Emissions by Fuel

Values in MMT CO_2e.

- Other: Kerosene; LPG; Lubricants; Lubricants (Transportation); Miscellaneous Petroleum Products; Petroleum Coke; Residual Fuel; Special Naphthas; Waxes

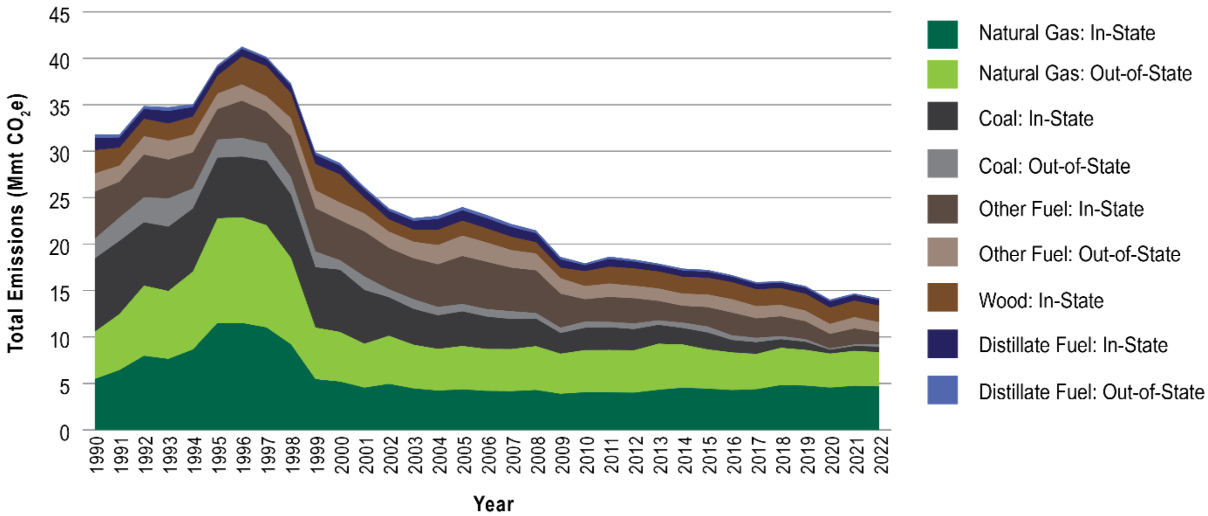


Table 29. New York State Industrial Sector Energy Emissions by Fuel Group and Context

Values in MMT CO_2e.

Fuel, Context	1990	2000	2010	2015	2019	2020	2021	2022
Coal, In-state	7.9	6.7	2.4	1.8	0.9	0.4	0.5	0.6
Coal, Out-of-state	2.1	1.0	0.7	0.7	0.3	0.2	0.2	0.3
Distillate Fuel, In-state	1.3	0.9	0.6	0.6	0.6	0.7	0.6	0.6
Distillate Fuel, Out-of-state	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Natural Gas, In-state	5.5	5.2	4.0	4.4	4.8	4.5	4.7	4.7
Natural Gas, Out-of-state	5.1	5.4	4.5	4.2	3.9	3.7	3.8	3.7
Wood, In-state	2.5	3.0	1.6	1.8	1.8	1.8	1.8	1.8
Other Fuel, In-state	5.0	4.3	2.4	2.1	1.9	1.5	1.7	1.3
Other Fuel, Out-of-state	2.0	1.9	1.4	1.4	1.2	1.1	1.2	1.1
Total	31.8	28.7	17.8	17.2	15.6	14.1	14.7	14.3

3.3.5 Transportation Sector

Figure 17 and Table 30 show total transportation sector energy emissions by fuel source for both on-road and nonroad vehicles. Gasoline is the largest source of emissions in the transportation sector. In 2022, gasoline consumption contributed 62.4 MMT CO_2e, or 55.8%, of transportation emissions. This was significantly lower than in 2021, while emissions from other fuels increased. Figure 18 shows emissions from on-road transportation only, along with total NYS on-road VMT for 1990–2022 (EPA 2024b).

Figure 17. New York State Transportation Sector Emissions by Fuel

Values in MMT CO_2e.

- Other: Natural Gas; Residual Fuel; Other

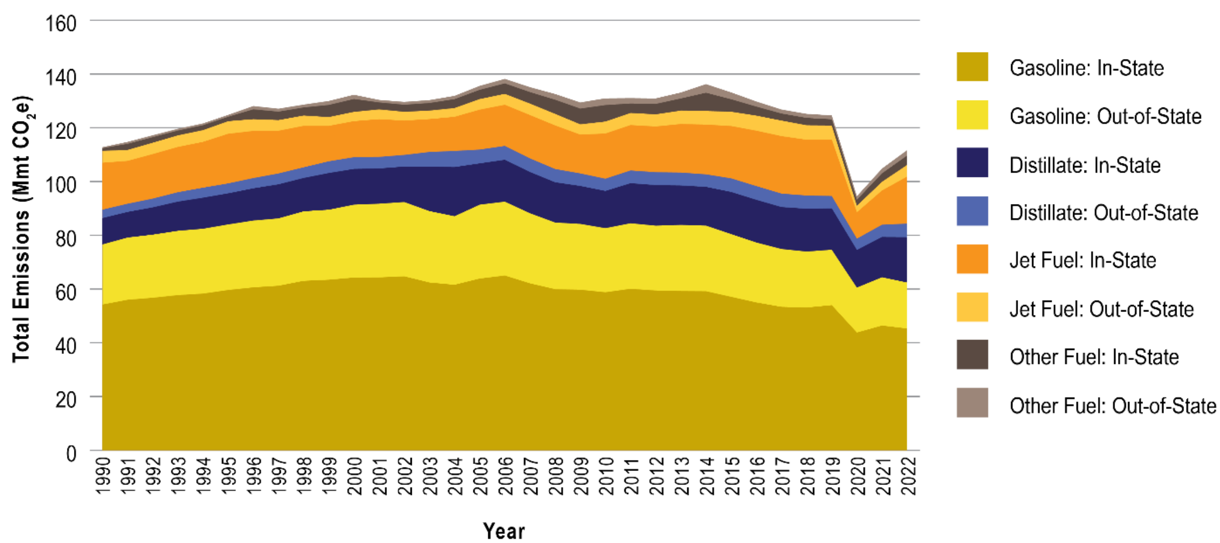


Table 30. New York State Transportation Sector Energy Emissions by Fuel Group and Context

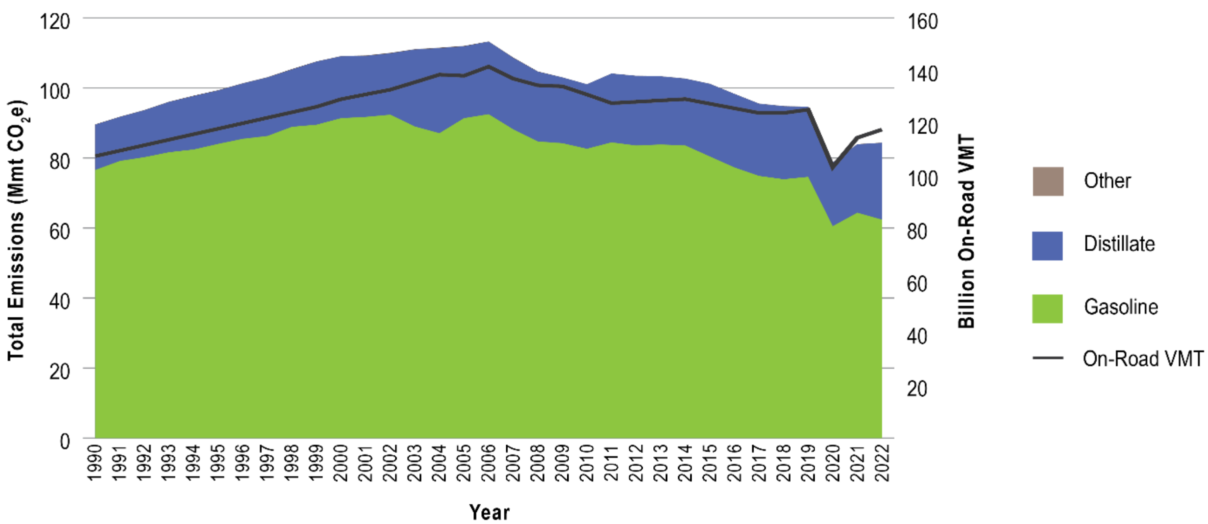
Values in MMT CO_2e.

Fuel, Context	1990	2000	2010	2015	2019	2020	2021	2022
Distillate, In-state	9.8	13.3	13.8	15.6	15.4	14.0	15.0	16.9
Distillate, Out-of-state	3.2	4.4	4.6	5.1	4.6	4.2	4.6	5.0
Gasoline, In-state	54.2	64.2	58.8	57.1	54.0	43.8	46.4	45.3
Gasoline, Out-of-state	22.4	27.2	23.9	23.4	20.6	16.8	18.0	17.1
Jet Fuel, In-state	17.4	13.4	16.8	19.5	21.0	9.8	12.7	17.5
Jet Fuel, Out-of-state	4.5	3.5	4.5	5.4	5.3	2.5	3.3	4.4
Other, In-state	0.9	4.8	6.1	4.6	2.3	2.2	3.1	3.5
Other, Out-of-state	0.4	1.6	2.5	2.6	1.5	1.3	1.8	2.0
Total	112.8	132.4	131.0	133.3	124.7	94.6	104.9	111.7

Figure 18. New York State On-Road Transportation Sector Emissions by Fuel Category and On-Road Vehicle Miles Traveled, 1990–2022

Values in MMT CO_2e.

- Distillate: Distillate Fuel; Diesel
- Gasoline: Gasoline; E85
- Other: Petroleum Coke; Lubricants; Miscellaneous Petroleum Products; Special Naphthas; Waxes; Lubricants (Transportation)



3.3.6 Oil and Gas Systems

Figure 19 and Table 31 display total emissions from the oil and gas sector across upstream, mid-stream, and downstream stages. In 2022, upstream oil and gas emissions contributed 3.0 MMT CO_2e, midstream contributed 4.9 MMT CO_2e, and downstream contributed 5.5 MMT CO_2e. For more details regarding the calculation of NYS oil and gas supply chain emissions, see *New York State Oil and Gas Sector Methane Emissions Inventory: 1990–2022* (NYSERDA 2024).

Figure 19. New York State Emissions from In-State Oil and Gas Systems by Stage

Values in MMT CO_2e.

- Upstream: Drill rigs; Drilling Fugitives; Oil/Gas Well: Mud Degassing; Oil/Gas Well Completions; Oil/Gas Conventional Production; Oil/Gas Abandoned Wells
- Midstream: Oil/Gas Gathering & Processing; Gathering Pipeline; Oil/Gas Truck Loading; Gas Processing Plant; Transmission Pipeline; Gas Transmission Compressor Stations; Gas Storage Compressor Stations; Storage Reservoir Fugitives; LNG Storage Compressor Stations; LNG Terminal
- Downstream: Distribution Pipeline Main/Services; Industrial/Commercial/Residential Meters; Commercial Buildings; Residential Gas Appliances; Residential Buildings

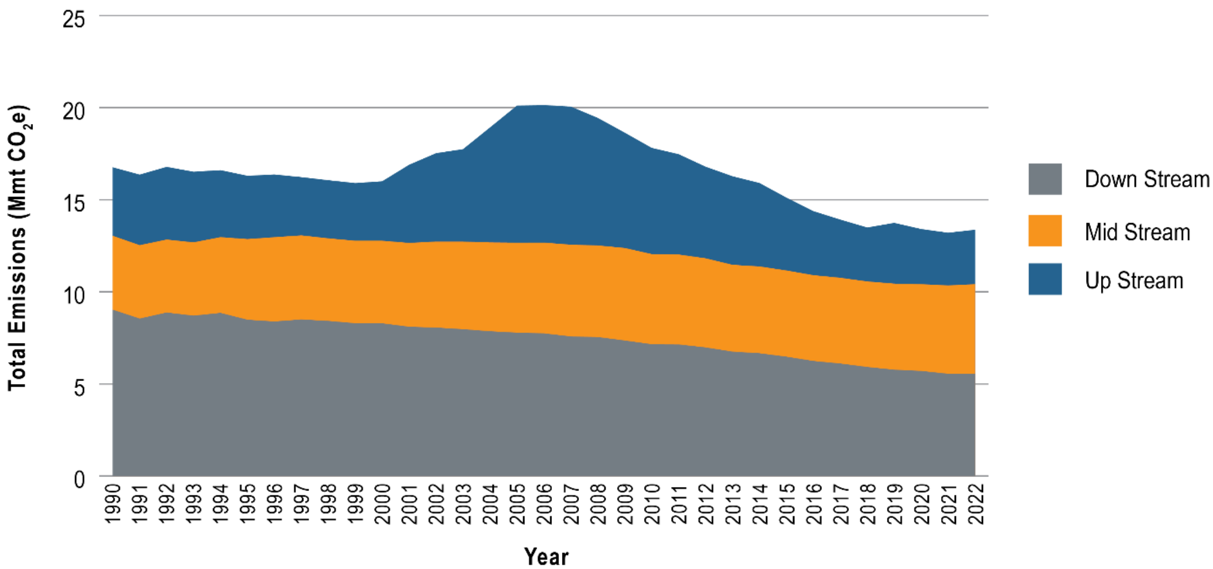


Table 31. New York State Oil and Gas Sector Energy Emissions by Context

Values in MMT CO_2e.

Context	1990	2000	2010	2015	2019	2020	2021	2022
Upstream	3.7	3.2	5.8	4.0	3.3	3.0	2.9	3.0
Midstream	4.0	4.5	4.9	4.7	4.7	4.7	4.8	4.9
Downstream	9.0	8.3	7.2	6.5	5.8	5.7	5.5	5.5
Total	16.7	16.0	17.9	15.2	13.8	13.4	13.2	13.4

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Appendix A. Review of Inventory Methods

To develop the methods for the in-state energy sector GHG Inventory, ERG first reviewed the 1990–2016 NYS GHG Inventory, along with the U.S. GHG Inventory and the California GHG Inventory. ERG then created a side-by-side comparison of the various methods and inventory characteristics, which Table A-1 summarizes.

Table A-1. Summary of Inventory Methodology Review (In-State)

Energy: Fossil Fuel Combustion (Electricity)	
Findings	NYS GHG Inventory method (1990–2016) is consistent with U.S. GHG Inventory and 2006 IPCC Guidelines.
Recommendations	Continue using NYS-specific energy data from “Patterns and Trends” (NYSERDA 2022), which leverages EIA SEDS; include biomass fuel combustion as a separate source category.
Energy: Fossil Fuel Combustion (Residential)	
Findings	NYS GHG Inventory method is consistent with U.S. GHG Inventory and 2006 IPCC Guidelines.
Recommendations	Continue using NYS-specific energy data from “Patterns and Trends” (NYSERDA 2022), which leverages EIA SEDS.
Energy: Fossil Fuel Combustion (Commercial)	
Findings	NYS Inventory method is consistent with U.S. Inventory and 2006 IPCC Guidelines.
Recommendations	Continue using NYS-specific energy data from “Patterns and Trends” (NYSERDA 2022), which leverages EIA SEDS.
Energy: Fossil Fuel Combustion (Industrial)	
Findings	NYS GHG Inventory method is consistent with U.S. GHG Inventory and 2006 IPCC Guidelines.
Recommendations	Continue using NYS-specific energy data from “Patterns and Trends” (NYSERDA 2022), which leverages EIA SEDS. Calculate nonenergy consumption activity based on industrial fuel nonenergy consumption fractions and industrial fuel storage fractions.

Table A-1. (continued)

Energy: Fossil Fuel Combustion (Transportation—On-Road Motor Vehicles)	
Findings	NYS GHG Inventory uses Federal Highway Administration and NYS Department of Transportation estimates, while U.S. GHG Inventory uses fuel consumption data for CO_2 and VMT estimates for CH_4 and N_2O.
Recommendations	Estimate county-level on-road motor vehicle emissions using county-level MOVES run. To the greatest extent possible, NYS-specific data and information will develop MOVES parameters; if necessary, default information will supplement NYS-specific data. ERG will obtain DEC's most recent MOVES inputs for the 2017 NEI and the 2016 modeling platforms (covering 2016, 2023, and 2028). ERG will adapt 2017 county databases so MOVES can use the data for other calendar years, starting from 1990 to the desired future year. The database modifications will match those ERG uses to support the EPA's modeling activities, where historic and future years rely on similar databases year to year. Exceptions will apply to commonly adjusted location-specific parameters, such as NYS-specific fuel properties, inspection and maintenance programs, and activity data. A key input will include the NYS-specific trend of vehicle population and VMT growth by vehicle class year over year. Age distribution will also play an important role in trend analysis because it determines activity allocation into vehicle model years, which are subject to varying fuel economy standards. When new input data is unavailable, ERG will rely on EPA methods used in current modeling efforts or MOVES model national data. Using MOVES to estimate emissions reduces uncertainty because it accounts for where emissions occur rather than where on-road fuels are purchased. This distinction may be particularly relevant to the New York Metropolitan Area, where fuels may be purchased in neighboring states while the associated vehicle traffic occurs in NYS.
Energy: Fossil Fuel Combustion (Transportation—Aviation)	
Findings	NYS GHG Inventory uses EIA SEDS data.
Recommendations	Disaggregate aviation fuel use from EIA SEDS based on the appropriate data series detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 through 2017* (EIA 2024f). Use passenger, freight, and mail miles from BTS to resolve potential aviation fuel discrepancies at large NYS airports. Follow IPCC Guidelines regarding boundaries for aviation activity.
Energy: Fossil Fuel Combustion (Transportation—Vessel Bunkering)	
Findings	NYS GHG Inventory uses EIA SEDS data.
Recommendations	Disaggregate marine fuel use from EIA SEDS based upon the appropriate data series as detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA 2024f). Follow IPCC Guidelines regarding boundaries for marine activity.
Energy: Fossil Fuel Combustion (Transportation—Railroad)	
Findings	NYS GHG Inventory uses EIA SEDS data.
Recommendations	Disaggregate locomotive fuel use from EIA SEDS based on the appropriate data series as detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA 2024f). Follow IPCC Guidelines regarding boundaries for locomotive activity.

Table A-1. (continued)

Energy: Fossil Fuel Combustion (Transportation—Other Nonroad)	
Findings	NYS GHG Inventory uses EIA SEDS data.
Recommendations	Disaggregate other nonroad fuel use from EIA SEDS based on the appropriate data series detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA 2024f). Clearly identify all nonroad fuel use across sectors. This source category will include nonroad fuel use that is not included elsewhere.
Energy: Oil and Gas Systems	
Findings	CO_2 and N_2O estimates are not included in the NYS GHG Inventory.
Recommendations	Continue using existing approach for CH_4. Derive CO_2/CH_4 and N_2O/CH_4 ratios from U.S. GHG Inventory data to estimate emissions for gas systems. Use Northeast National Energy Modeling System region data for the production sector and national data for other sectors. Use pollutant ratios developed from U.S. GHG Inventory data to estimate CO_2 and N_2O emissions for oil systems. EIA data indicate that a single refinery operated in NYS in 1990 and 1991. Scale national refinery emissions from the U.S. GHG Inventory for 1990–1991 using the ratio of state-to-national crude oil distillation capacity for operating refineries (EIA 2019b). Consider potential adjustments based on top-down studies as indicated in the NAS report (NAS 2018).

Appendix B. Fuel Carbon Contents and Combustion Emission Factors

Table B-1 provides the carbon contents for selected fuel types used in the NYS energy sector GHG inventory for 2022. Table B-2 lists the CH_4 and N_2O combustion emission factors for these selected fuels in the NYS energy sector GHG Inventory for 2022. The units are based on those used in the original data source for the carbon contents and emission factors.

Table B-1. Carbon Content of Selected Fuels, 2022

Values in MT/10^9 Btu.

Source: EPA (2024c).

Sector	Fuel	Carbon Content
Electricity	Coal	26.13
Electricity	Distillate fuel	20.22
Electricity	Natural gas	14.43
Electricity	Petroleum coke	27.85
Electricity	Residual fuel	20.48
Electricity	Wood	28.13
Residential	Coal	26.18
Residential	Distillate fuel	20.22
Residential	Kerosene	19.96
Residential	LPG	17.15
Residential	Natural gas	14.43
Residential	Wood	28.13
Commercial	Coal	26.18
Commercial	Distillate fuel	20.22
Commercial	Kerosene	19.96
Commercial	LPG	17.15
Commercial	Natural gas	14.43
Commercial	Residual fuel	20.48
Commercial	Wood	28.13
Industrial	Asphalt and road oil	20.55
Industrial	Coal: coking	25.61
Industrial	Coal: other	26.1
Industrial	Distillate fuel	20.22
Industrial	Kerosene	19.96
Industrial	LPG	17.15
Industrial	Lubricants	20.2
Industrial	Miscellaneous petroleum products	20.31

Table B-1. (continued)

Sector	Fuel	Carbon Content
Industrial	Natural gas	14.43
Industrial	Petroleum coke	27.85
Industrial	Residual fuel	20.48
Industrial	Special naphthas	19.74
Industrial	Waxes	19.8
Industrial	Wood	25.6
Transportation	Motor gasoline	19.27
Transportation	Distillate	20.22
Transportation	Aviation gasoline	18.86
Transportation	Jet fuel	19.7
Transportation	Residual fuel	20.48
Transportation	Natural gas	14.43

Table B-2. Methane and Nitrous Oxide Combustion Emission Factors, 2021

Sources: EPA (2024c), IPCC (2006a).

Sector	Fuel	CH_4	N_2O	Units
Electricity	Coal	0.7	3.6	g/GJ
Electricity	Distillate fuel	0.9	0.4	g/GJ
Electricity	Natural gas	1	0.3	g/GJ
Electricity	Petroleum coke	0.7	3.6	g/GJ
Electricity	Residual fuel	0.8	0.3	g/GJ
Electricity	Wood	11	7	g/GJ
Residential	Coal	300	1.5	g/GJ
Residential	Distillate fuel	10	0.6	g/GJ
Residential	Kerosene	10	0.6	g/GJ
Residential	LPG	5	0.1	g/GJ
Residential	Natural gas	5	0.1	g/GJ
Residential	Wood	300	4	g/GJ
Commercial	Coal	10	1.5	g/GJ
Commercial	Distillate fuel	10	0.6	g/GJ
Commercial	Kerosene	10	0.6	g/GJ
Commercial	LPG	5	0.1	g/GJ
Commercial	Natural gas	5	0.1	g/GJ
Commercial	Residual fuel	10	0.6	g/GJ
Commercial	Wood	300	4	g/GJ
Industrial	Asphalt and road oil	3	0.6	g/GJ
Industrial	Coal: coking	10	1.5	g/GJ
Industrial	Coal: other	10	1.5	g/GJ
Industrial	Distillate fuel	3	0.6	g/GJ

Table B-2. (continued)

Sector	Fuel	CH_4	N_2O	Units
Industrial	Kerosene	3	0.6	g/GJ
Industrial	LPG	1	0.1	g/GJ
Industrial	Lubricants	3	0.6	g/GJ
Industrial	Miscellaneous petroleum products	3	0.6	g/GJ
Industrial	Natural gas	1	0.1	g/GJ
Industrial	Petroleum coke	3	0.6	g/GJ
Industrial	Residual fuel	3	0.6	g/GJ
Industrial	Special naphthas	3	0.6	g/GJ
Industrial	Waxes	3	0.6	g/GJ
Industrial	Wood	30	4	g/GJ
Transportation: On-road[a]	Motor gasoline	25	8	g/GJ
Transportation: On-road[a]	Distillate	3.9	3.9	g/GJ
Transportation: Aviation	Aviation gasoline	60	0.9	g/GJ
Transportation: Aviation	Jet fuel	0	2.5	g/GJ
Transportation: Railroad	Distillate fuel	0.25	0.08	g/kg fuel
Transportation: Military	Distillate fuel	2.039	0.054	g/kg fuel
Transportation: Military	Residual fuel oil	0.309	0.088	g/kg fuel
Transportation: Bunker Vessel	Distillate fuel	2.039	0.054	g/kg fuel
Transportation: Bunker Vessel	Residual fuel oil	0.309	0.09	g/kg fuel
Transportation: Other Nonroad	Distillate fuel	0.318	0.296	g/kg fuel
Transportation: Other Nonroad	Industrial/commercial equipment: gasoline—4 stroke	1.006	0.563	g/kg fuel
Transportation: Other Nonroad	Construction/mining equipment: equipment gasoline—4-stroke	1.025	0.530	g/kg fuel
Transportation: Other Nonroad	Airport equipment gasoline—4-stroke	0.383	0.400	g/kg fuel
Transportation: Other Nonroad	Lawn and garden equipment: residential gasoline—4-stroke	1.084	0.701	g/kg fuel
Transportation: Other Nonroad	Ships and boats: gasoline—4-stroke	0.813	0.003	g/kg fuel
Transportation: Other Nonroad	Recreational equipment: gasoline—4-stroke	0.982	0.535	g/kg fuel

[a] Emission factors are used exclusively in the fuel consumption method. For CH_4 and N_2O emissions, MOVES calculates these internally within its model.

Appendix C. Motor Vehicle Emission Simulator (MOVES) Model Settings

C.1 Motor Vehicle Emission Simulator Run Settings and New York State Input Data

The Motor Vehicle Emission Simulator (MOVES) model was executed for calendar years 1990 and 1999–2022 using the model's Default Scale, a detail level allowing emissions at various geographic resolutions (e.g., nation, state, or county) using entirely prepopulated data. Users can also provide local data for any table. For the NYS GHG Inventory, MOVES used the Default Scale to estimate the statewide GHG emissions with updated vehicle miles traveled (VMT) and vehicle population data to better represent the NYS vehicle fleet mix. Since MOVES does not support calendar years 1991–1998, the NYS GHG Inventory interpolated emissions between 1990 and 1999 for these eight years.

Other MOVES data, such as age distribution, vehicle speed distributions, fuel formulations, fuel type distribution, temperature and relative humidity, and inspection and maintenance programs, were left at default settings. To model the 1990 and 1999–2022 calendar years, three custom database tables were created for MOVES:

1. Statewide annual VMT by Highway Performance Monitoring System (HPMS) vehicle type groups
2. Statewide vehicle population by MOVES source use types
3. Updated geographic allocation factors summing to one across the 62 NYS counties

Table C-1 lists the input parameters and ran settings used in MOVES for New York State.

Table C-1. Motor Vehicle Emission Simulator Input Parameters and Run Settings Selected for New York State

MOVES Input Parameter	MOVES Run Setting/Selection
Model	On-road
Domain/Scale	Default
Calculation Type	Inventory
Time Aggregation Level	Year
Years	1990, 1999–2022
Months	12 months
Days	Weekday, weekend day

Table C-1. (continued)

MOVES Input Parameter	MOVES Run Setting/Selection
Hours	24 hours
States	New York State
Fuels	All fuel types selected
Source Use Types	All vehicle types selected
Selected Road Types	All roads selected: off-network, rural restricted, rural unrestricted, urban restricted, urban unrestricted
Pollutants and Processes	Pollutants: CO_2, CH_4, N_2O, and the required precursors (total hydrocarbons and total energy consumption) Processes: Running, start, extended idle, crankcase running, crankcase start, crankcase extended idle, auxiliary power unit extended idle
Create Input Datasets	Custom input database for NYS containing tables for: HPMSVtypeYear, 1990 and 1999–2021 VMT SourceTypeYear, 1990 and 1999–2021 population ZoneRoadType, normalized county allocation factors
Output Database (assigned name)	nyserda_1990to2022_out
Output Units	Mass: U.S. ton (later converted to mt) Energy: Kilojoules Distance: Miles
Output Activity Types	distance traveled, population
Output Time	Year
Output Location	State
Output Selections for All Vehicle/Equipment Categories	Fuel Type
Output Selections for On- and Off-Road	Source Use Type
Advanced Features	Time Aggregation set to Year Region Aggregation set to State Input Datasets, Selections, set to nyserda_1990to2022_in

The VMT values used in MOVES for New York State are shown in Table C-2 for select years in the time series.

Table C-2. Motor Vehicle Emission Simulator Vehicle Miles Traveled Input for New York State

Values in million miles.

HPMS Vehicle Type	1990	2000	2010	2015	2020	2021	2022
10: Motorcycles	107	415	718	738	498	394	439
25: Light Duty Vehicles	102,532	117,008	122,426	117,237	93,657	98,810	106,566
40: Buses	540	897	644	974	559	692	978
50: Single Unit Trucks	1,974	4,664	3,610	4,506	3,785	3,434	3,849
60: Combination Trucks	1,748	6,073	3,854	3,775	3,978	3,542	3,561

The MOVES population inputs for New York State are shown in Table C-3 for select years.

Table C-3. New York State Vehicle Population

MOVES Source Type	1990	2000	2010	2015	2020	2021	2022
11: Motorcycle	34,319	148,222	310,646	323,910	231,638	197,250	211,797
21: Passenger Car	7,574,379	6,360,158	6,050,557	4,760,186	3,826,905	3,665,185	3,704,527
31: Passenger Truck	1,859,092	3,397,238	4,204,400	5,011,430	4,939,978	5,030,757	5,345,565
32: Light Commercial Truck	175,746	321,151	397,455	473,745	466,993	475,573	505,333
41: Intercity Bus	9,040	14,451	13,315	18,010	12,658	14,269	19,960
42: Transit Bus	2,530	4,045	4,165	6,220	3,985	4,394	6,147
43: School Bus	16,713	26,718	22,071	29,099	17,963	20,052	28,050
51: Refuse Truck	1,594	4,581	2,772	2,787	1,810	1,587	1,788
52: Single Unit Short-Haul Truck	91,949	242,500	219,295	288,806	268,269	235,182	264,940
53: Single Unit Long-Haul Truck	4,055	10,695	9,671	12,738	11,832	10,373	11,685
54: Motor Home	22,170	47,503	36,152	43,329	36,383	31,896	35,932
61: Combination Short-Haul Truck	16,259	52,256	36,211	36,211	39,752	34,193	34,119
62: Combination Long-Haul Truck	9,729	38,515	23,047	24,700	26,418	22,724	22,675

C.2 Vehicle Miles Traveled Inputs to Motor Vehicle Emission Simulator

The annual VMT provided to MOVES for 1990 and 1999–2016 matches the values from the previous NYS GHG Inventory (NYSERDA 2019a). These values align with the VMT reported for New York State in the Federal Highway Administration's (FHWA) Highway Statistics Table VM-2. To complete the time series, NYS VMT data for 2017–2022 were extracted from the FHWA VM-2 tables.

The VM-2 table provides total VMT by functional class (roadway type) but does not break down the activity by vehicle class. This distinction was derived from the FHWA Highway Statistics Table VM-4, which contains state-specific distributions of VMT by HPMS vehicle classes. The VM-4 data are available for several years in the time series, specifically 1994–1999, 2009–2010, 2013–2015, and 2017–2022. For most years without VM-4 coverage, the vehicle type mix was interpolated between the closest two years with available VM-4 data.

While the VM-4 tables are available for several years in the time series, they were not available for the base year 1990, requiring a different approach. For 1990, VMT were estimated by HPMS vehicle type through a remapping of the 1990 VMT from the prior State Inventory Tool (SIT). The vehicle type mapping was accomplished in two steps. In the first step, shown in Table C-4, motorcycle VMT remained unchanged; light-duty vehicles were grouped into a combined group of HPMS vehicle type category 25 (all light-duty vehicles); and heavy-duty vehicles were aggregated into a combined group of HPMS vehicle types, including 40 (buses), 50 (single-unit trucks), and 60 (combination trucks).

Table C-4. Step 1: Aggregation from State Inventory Tool to Groups of Motor Vehicle Emission Simulator Highway Performance Monitoring System Vehicle Types

SIT Vehicle Category Name	SIT VMT (millions)	HPMS Vehicle Type(s)	HPMS Vehicle Type VMT (millions)
Motorcycle	107	10	107
Light-Duty Gasoline Vehicle	77,810	25	102,517
Light-Duty Gasoline Truck	21,599		
Light-Duty Diesel Vehicle	2,148		
Light-Duty Diesel Truck	960		
Heavy-Duty Gasoline Truck	1,273	40, 50, 60	4,261
Heavy-Duty Diesel Truck	2,988		
Total	***106,901***		***106,901***

Table C-5 shows the disaggregation of heavy-duty vehicles into the three HPMS vehicle types 40 (buses), 50 (single-unit trucks), and 60 (combination trucks). The data source for this disaggregation is the NYS MOVES county database submittal for the 2017 NEI (EPA 2019b). VMT data was extracted from the 62 county databases, summed to the statewide level, and then used to compute the relative fraction of NYS-specific VMT for buses, single-unit trucks, and combination trucks at the state level. Table C-5 shows the resulting mapping fractions.

Table C-5. Step 2: Disaggregation into All Five Motor Vehicle Emission Simulator Highway Performance Monitoring System Vehicle Types

HPMS Vehicle Type, 3 Categories	SIT VMT (millions of miles)	HPMS Vehicle Type, 5 Categories	Mapping Fraction	Resulting HPMS VMT for Input to MOVES (millions of miles)
10	107	10	1	107
25	102,532	25	1	102,532
40, 50, 60	4,262	40	0.127	540.15
		50	0.463	1,973.95
		60	0.410	1,747.90
Total	***106,901***	—	—	***106,901***

The NYS-specific mapping fractions for buses, single-unit trucks, and combination trucks differ from the national average defaults in MOVES. The MOVES4 default relative fractions are 0.054 for buses, 0.373 for single-unit trucks, and 0.572 for combination trucks. Compared to the national averages, New York State has a higher portion of bus and single-unit truck VMT and a lower proportion of combination truck VMT.

Table C-6 is a reference table illustrating how HPMS vehicle types correspond to MOVES source use types. At the start of a model run, MOVES allocates VMT by HPMS vehicle type into the 13 source types using a combination of source type population, age distribution, and relative mileage accumulation rates.

Table C-6. Motor Vehicle Emission Simulator Highway Performance Monitoring System Vehicle and Source Type Descriptions

HPMS Vehicle Type ID	HPMS Vehicle Description	Source Type ID	Source Type Description
10	Motorcycles	11	Motorcycle
25	Light-Duty Vehicles	21	Passenger Car
		31	Passenger Truck
		32	Light Commercial Truck
40	Buses	41	Intercity Bus
		42	Transit Bus
		43	School Bus
50	Single-Unit Trucks	51	Refuse Truck
		52	Single-Unit Short-Haul Truck
		53	Single-Unit Long-Haul Truck
		54	Motor Home
60	Combination Trucks	61	Combination Short-Haul Truck
		62	Combination Long-Haul Truck

As mentioned, the NYS-specific VMT mix by HPMS vehicle class (VM-4 table) was available for 1999, 2009–2010, 2013–2015, and 2017–2022. For these years, the VM-4 VMT data were directly allocated to the five HPMS vehicle types. For 2000–2008, 2011–2012, and 2016, the VMT mix by HPMS vehicle type was interpolated from the closest two years, including 1990 and others with VM-4 data. During a MOVES run, the model apportions the input VMT by HPMS vehicle types into source types, model years, and fuel types using the underlying data in the model database.

C.3 Population Inputs to Motor Vehicle Emission Simulator

Due to the unavailability of 1990–2022 vehicle population data for New York State, the MOVES-based estimates relied on MOVES model assumptions (EPA 2024b) regarding annual mileage accrued per vehicle. MOVES source types categorize vehicle population inputs, and the input table was prepared by dividing the annual source type VMT by the MOVES default VMT-to-population ratio. The annual mileage accumulation rates vary by source type and model year, and the source type average varies by calendar year. Table C-7 shows the average VMT-to-population ratio for 1990. In MOVES, VMT per vehicle per year tends to increase over time. Year-specific ratios were multiplied by the corresponding year's VMT to estimate vehicle populations for 1990 and 1999–2022.

Table C-7. Vehicle Miles Traveled-to-Population Ratios, 1990

Source Type ID	Source Type Description	MOVES Default Ratio (miles/vehicle/year)
11	Motorcycle	3,118
21	Passenger Car	10,557
31	Passenger Truck	11,081
32	Light Commercial Truck	11,214
41	Intercity Bus	30,660
42	Transit Bus	30,654
43	School Bus	11,095
51	Refuse Truck	31,646
52	Single Unit Short-Haul Truck	17,731
53	Single Unit Long-Haul Truck	33,719
54	Motor Home	7,057
61	Combination Short-Haul Truck	41,144
62	Combination Long-Haul Truck	110,904

C.4 Other Important Data: Vehicle Age and Fuel Type Distributions

The MOVES model was provided with annual VMT and population data at the state level for New York State. The model then allocated this activity to the 62 counties in the State using a modified version of the ZoneRoadType table. The MOVES data source for the county allocation factors in the ZoneRoadType table is derived from 2011 HPMS state-level data collected annually by the FHWA that the EPA processed for the NEI (EPA 2023). This allocation of VMT activity to counties is critical to the statewide inventory because different counties are associated with varying ethanol blends depending on the calendar year.

MOVES uses several underlying model tables to determine the age and fuel type of incoming VMT and population data. The model first disaggregates VMT from HPMS vehicle types into source types and model years using the age distribution by source type from the SourceTypeAgeDistribution table and the relative annual mileage accumulation rates from the SourceTypeAge table. National age distributions in MOVES are derived from historical vehicle registration data for two years, 1999 and 2020. The age distributions are projected for the other years based on an algorithm that accounts for growth and vehicle scrappage as vehicles age. The EPA did not obtain the registration data for every calendar year because doing so is prohibitively costly, so it is used to estimate the distributions for those years. In addition, MOVES uses age distributions directly, without using mileage accrual rates, to distribute vehicle population into vehicle model years or ages.

To allocate VMT by vehicle age, MOVES incorporates relative mileage accumulation in addition to age distribution, recognizing that older vehicles generally travel fewer miles annually than newer vehicles. MOVES primarily uses the 2002 Bureau of Transportation Statistics (BTS) Vehicle Inventory and Use Survey (VIUS) (U.S. Census 2004) and a 2001 National Highway Traffic Safety Administration (NHTSA) survey (EPA 2020b) as the sources for relative annual mileage accumulation rates. After MOVES apportions VMT and population into source types and model years, it estimates the share of gasoline, diesel, compressed natural gas (CNG), and E85-capable (flex-fuel) vehicles in each model year. Flex-fuel vehicles can operate on high-ethanol fuels such as E85 or conventional gasoline, depending on local fuel availability. MOVES uses the SampleVehiclePopulation table to distribute model year, VMT, and population into fuel types, drawing on the 2014 vehicle registration data and 2002 VIUS classifications. Additionally, MOVES can adjust this information using the Alternative Fuel Vehicle and Technology (AFVT)) table lists the source type, model year, fuel type, and vehicle population fraction for each combination, ensuring that the fractions sum to one for each source type and model year.

C.5 Alternative Fuels and Biogenic Fuel Supply

At the county level, fuel supply for NYS vehicles is specified via the MOVES database FuelSupply table, which includes the market shares of conventional gasoline versus ethanol blend E10 by fuel region. MOVES classifies NYS counties into two fuel regions: one containing 12 downstate counties (Bronx, Dutchess, Kings, Nassau, New York, Orange, Putnam, Queens, Richmond, Rockland, Suffolk, and Westchester) and with the State's remaining 50 counties. The 12-county area uses more ethanol and begins using ethanol earlier in the time series than the 50-county area. Between 1993 and 2012, the 12-county area used E10, and the 50-county area used mostly conventional gasoline, with some E10. Starting in 2012, MOVES assumes the entire State uses E10. The alternative fuels CNG, E85, and biodiesel are not tied to specific fuel regions but are applied universally in the model. MOVES determines the presence of CNG- and E85-capable vehicles by model year using the SampleVehiclePopulation table.

MOVES4, used for this inventory, estimates CNG for heavy-duty source types, with the CNG amount growing steadily from 1990–2022. Similarly, MOVES estimates flex-fuel vehicles for three source types: passenger cars, passenger trucks, and light commercial trucks. MOVES assigns a fuel type fraction of zero to flex-fuel vehicles through model year 1997, 1% to 2% in 1998, and increasing percentages in later years. These flex-fuel vehicles can operate on either gasoline or E85. MOVES assumes that less than 2% of flex-fuel vehicles will use high-ethanol E85 fuel in calendar years 2010 and later. In the MOVES FuelSupply and FuelFormulation tables, the model assumes conventional diesel (B0) is in use through 2010, switching entirely to B3.4 (3.4% biodiesel) starting in 2011. For this inventory, MOVES assumes that biodiesel will not be used in New York State until 2014.

C.6 Separate Tracking of Ethanol Fuels

This study required separating the CO_2 emissions from the fossil-fuel portion of fuels from the biogenic portion. Biogenic fuels include ethanol mixed with conventional gasoline to make E10 and E85 and the volume of biodiesel ester mixed with conventional diesel to make biodiesel. MOVES fuel type identification codes and fuel supply assumptions facilitate straightforward accounting for E85 (separate from gasoline) and biodiesel (separate from conventional diesel). However, MOVES does not output E10 as a fuel type separate from E0. Instead, MOVES labels both as fuel type ID = 1. To account for this, a separate set of MOVES runs was performed over 1999–2022 that zeroed out the market shares of E0, leaving only the E10 fuel-based gasoline emissions. Subtracting the E10-only results from the total gasoline results of the main run provided separate results for E0 versus E10 from 1999–2011. From 2012 onward, the fuel supply in MOVES for New York State is entirely E10, and the 1990 fuel supply is entirely E0. The separate accounting for E0, E10, E85, B0, and biodiesel fuels allows for the calculation of the biogenic portion of CO_2 as follows:

- 10% of the E10-fueled CO_2
- 74% of the E85-fueled CO_2
- 5% of the 5% diesel (B5) CARB-fueled CO_2

E85 contains between 70% and 85% ethanol; the MOVES fuel formulation database table assumes a 74% ethanol level.

An example calculation demonstrating how the MOVES calculates for CO_2 is:

Equation C-1

$$\boldsymbol{CO_2 = Total\ Energy\ Consumed \times CC \times OF \times \frac{44}{12}}$$

where,

Total Energy Consumed = Calculated by MOVES based on rates of energy required to operate any vehicle type over a wide range of speeds and power-based operating modes, based on analysis of millions of seconds of in-use data

CC = Carbon content of fuel (g/kg of energy)

OF = Fraction of carbon that is oxidized to form CO_2 in the atmosphere; MOVES assumes an oxidation fraction of 1 for hydrocarbon-based fuels

44 = Molecular mass of CO_2

12 = Atomic mass of carbon

Figure C-1 and Table C-8 compare CO_2e emissions estimated using the MOVES model and the prior SIT-based approach. The prior SIT results came from the spreadsheet Mobile Combustion-pm07.xlsm (two tabs, Summary and CO_2 Summary). The numbers in Figure C-1 and Table C-8 represent the Mobile Sources total minus the nonhighway subtotal CO_2e. Because the prior SIT combined CH_4 and N_2O into CO_2e using AR4 100-year GWP values for comparison. The relatively larger percent differences between 1991 and 2004 for the prior MOVES2014b and the prior SIT results are likely due to an assumption of lower heavy-duty vehicle VMT contribution in the prior SIT. MOVES3 estimates higher CO_2 emissions than MOVES2014b by approximately 6% to 8% in near-term years (EPA 2021), although reductions are expected in future years due to the Heavy-Duty GHG Phase 2 rule and the Safer Affordable Fuel-Efficient (SAFE) vehicles rule. MOVES3 also estimates major changes in methane emissions, although these comprise a small portion of the CO_2e presented in Figure C-1. MOVES4 estimates similar GHG emissions to MOVES3 for the entire time series, with GHG reductions relative to MOVES3 beginning with model year 2027. This change does not impact the NYS trends from 1990 through 2022.

Figure C-1. Comparison of Transportation Model Cardon Dioxide Equivalent Emissions Trends by Year

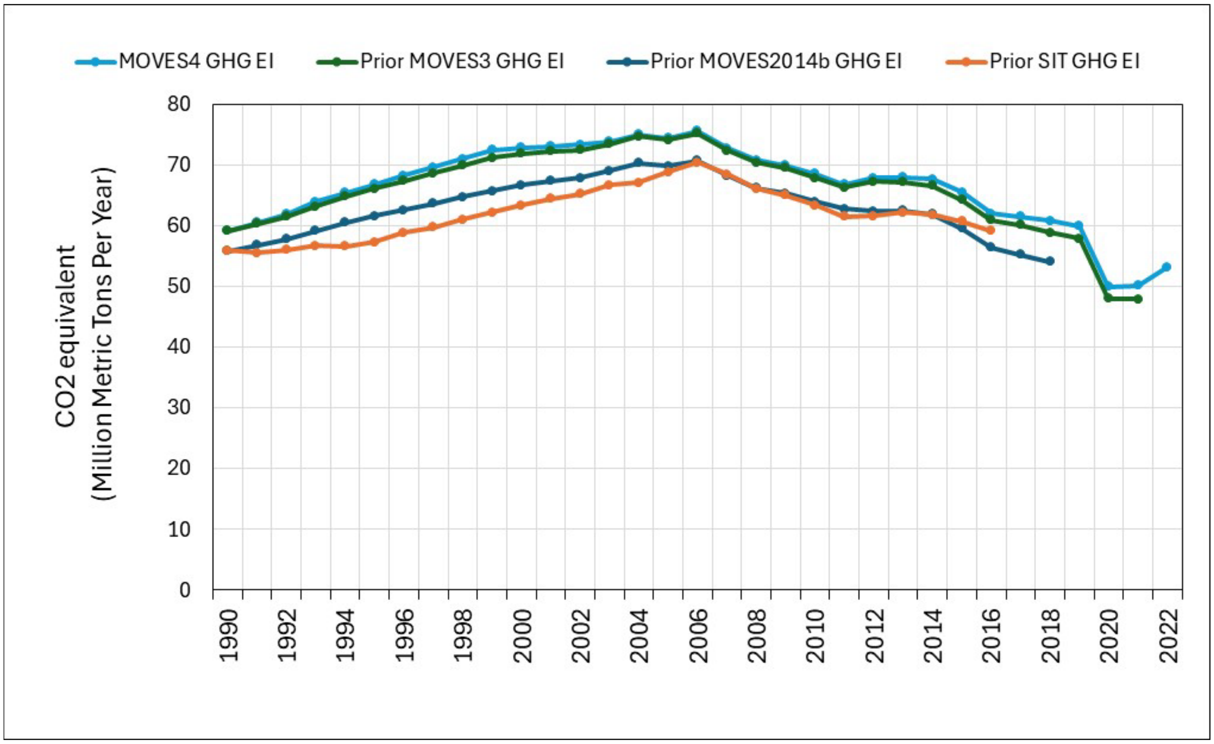


Table C-8. Comparison of Motor Vehicle Emission Simulator 4-Based Greenhouse Gas Emissions Inventory with the Prior State Inventory Tool Greenhouse Gas Emissions Inventory by Year

Year	MOVES4-Based GHG Emissions Inventory (MT CO_2e)	Prior SIT GHG Emissions Inventory (MT CO_2e)	Percent Difference (MOVES4-SIT)/SIT
1990	59,141,746	55,929,851	5.7%
1991	60,486,196	55,487,679	9.0%
1992	61,830,649	55,995,700	10.4%
1993	63,964,558	56,658,136	12.9%
1994	65,372,500	56,561,210	15.6%
1995	66,780,443	57,258,118	16.6%
1996	68,188,386	58,873,038	15.8%
1997	69,596,328	59,695,083	16.6%
1998	71,004,271	61,012,490	16.4%
1999	72,412,214	62,181,873	16.5%
2000	72,776,268	63,379,215	14.8%
2001	72,981,246	64,362,308	13.4%
2002	73,325,166	65,223,338	12.4%
2003	73,792,718	66,702,505	10.6%
2004	74,965,343	67,028,478	11.8%
2005	74,410,599	68,791,539	8.2%
2006	75,573,263	70,409,700	7.3%
2007	72,698,994	68,382,003	6.3%
2008	70,790,992	66,095,772	7.1%
2009	69,859,564	65,020,231	7.4%
2010	68,494,017	63,380,244	8.1%
2011	66,718,211	61,504,645	8.5%
2012	67,835,612	61,565,912	10.2%
2013	67,924,737	62,108,961	9.4%
2014	67,656,089	61,758,601	9.5%
2015	65,445,180	60,729,501	7.8%
2016	62,006,918	59,112,860	4.9%
2017	61,443,424	—	—
2018	60,740,628	—	—
2019	59,946,686	—	—
2020	49,975,428	—	—
2021	50,147,348	—	—
2022	53,123,207	—	—

[a] CH_4 and N_2O are converted to an AR4 100-year basis to ensure consistency with the prior SIT GWP values.

Appendix D. Summary Tables of Fossil Fuel Emission Factors

This appendix provides a stage-level breakdown of well-to-combustion emission factors for coal, distillate fuel, gasoline, and natural gas consumed in New York State. The stages include out-of-state (further broken down into substages specified in Table D-1), in-state, and combustion. The emission factors for coal and natural gas are representative of electricity end-use, while those for distillate fuel and gasoline are representative of on-road motor vehicle use. (Note that the emission factors for distillate fuel and gasoline exclude the biogenic portion of the blended feedstock).

Table D-1. Out-of-State Substages by Fuel Type

Out-of-State Stage	Coal	Distillate	Gasoline	Natural Gas
1	Extraction and processing	Extraction	Extraction	Production
2	Transportation	Processing through distribution	Processing through distribution	Gathering and boosting
3	—	—	—	Processing
4	—	—	—	Transmission

Emission factors are presented based on two units: Table D-2 lists values in pounds (lb) CO_2e/mmBtu, and Table D-3 provides values are in raw lb of pollutant/mmBtu. Both tables include three sets of emission factors for natural gas, corresponding to the three sensitivities (Low, Mid, High) described in section 2.2.1.1 of the main report.

Table D-2. Well-to-Combustion Fossil Fuel Emission Factors, 2022

Values in lb CO_2e/MMBtu. The GWP factors are based on the IPCC 2013 (AR5 GWP20), as shown in Table E-1.

Stage	Out-of-State Stage #	Pollutant	Coal	Distillate	Gasoline	Propane	Low	Mid	High
							Natural Gas		
Out-of-state	1	CO_2	5.91	12.10	10.46	10.99	6.68	6.68	6.68
		CH_4	85.13	18.09	15.63	16.42	13.83	28.52	38.25
		N_2O	0.06	0.05	0.04	0.05	3.87E-3	3.87E-3	3.87E-3
Out-of-state	2	CO_2	1.36	17.96	29.97	24.45	7.24	7.24	7.24
		CH_4	0.003	3.60	7.40	5.65	9.07	9.07	10.25
		N_2O	0.003	0.09	0.14	0.11	1.77E-5	1.77E-5	1.77E-5
Out-of-state	3	CO_2					3.04	3.04	3.04
		CH_4					2.50	2.50	4.00
		N_2O					3.14E-3	3.14E-3	3.14E-3
Out-of-state	4	CO_2					9.13	9.13	9.13
		CH_4					6.88	6.88	9.50
		N_2O					0.06	0.06	0.06
Out-of-state	***Total***	**CO_2**	**7.27**	**30.06**	**40.43**	**35.44**	**27.67**	**27.67**	**27.67**
		CH_4	**85.13**	**21.69**	**23.02**	**22.07**	**32.66**	**47.36**	**62.37**
		N_2O	**0.06**	**0.15**	**0.18**	**0.16**	**0.08**	**0.08**	**0.08**
		CO_2e	**92.46**	**51.90**	**63.64**	**57.67**	**60.41**	**75.10**	**90.12**
In-state	In-state	CO_2					0.07	0.10	0.10
		CH_4					14.66	17.11	17.11
		N_2O					5.3E-05	1.0E-04	1.0E-04
		CO_2e					**14.73**	**17.22**	**17.22**
Out-of-state + in-state	***Out-of-state + in-state***	**CO_2**	**7.27**	**30.06**	**40.43**	**35.44**	**27.74**	**27.77**	**27.77**
		CH_4	**85.13**	**21.69**	**23.02**	**22.07**	**47.32**	**64.47**	**79.48**
		N_2O	**0.06**	**0.15**	**0.18**	**0.16**	**0.08**	**0.08**	**0.08**
		CO_2e	**92.46**	**51.90**	**63.64**	**57.67**	**75.14**	**92.32**	**107.34**
Combustion	Combustion	CO_2	211.14	155.57	144.12	138.63	116.65	116.65	116.65
		CH_4	0.14	0.30	0.47	0.20	0.20	0.20	0.20
		N_2O	2.21	0.24	0.75	0.06	0.18	0.18	0.18
Well-to-combustion total	***Well-to-combustion total***	**CO_2**	**218.41**	**185.63**	**184.55**	**174.07**	**144.38**	**144.42**	**144.42**
		CH_4	**85.27**	**21.99**	**23.50**	**22.27**	**47.52**	**64.66**	**79.68**
		N_2O	**2.27**	**0.38**	**0.93**	**0.22**	**0.27**	**0.27**	**0.27**
Well-to-combustion total	***Well-to-combustion total***	**CO_2e**	**305.95**	**208.00**	**208.97**	**196.56**	**192.16**	**209.34**	**224.36**

Table D-3. Well-to-Combustion Fossil Fuel Emission Factors, 2022

Values in lb/MMBtu. The emissions are shown unadjusted, with no GWP factors applied.

Stage	Out-of-State Stage #	Pollutant	Coal	Distillate	Gasoline	Propane	Low	Mid	High
							Natural Gas		
Out-of-state	1	CO_2	5.91	12.1	10.5	11.0	6.68	6.68	6.68
		CH_4	1.01	0.22	0.19	0.20	0.16	0.34	0.46
		N_2O	2.2E-04	1.9E-04	1.7E-04	1.7E-04	1.5E-05	1.5E-05	1.5E-05
Out-of-state	2	CO_2	1.36	18.0	30.0	24.4	7.24	7.24	7.24
		CH_4	4.0E-05	0.04	0.09	0.07	0.11	0.11	0.12
		N_2O	1.2E-05	3.6E-04	5.3E-04	4.2E-04	6.7E-08	6.7E-08	6.7E-08
Out-of-state	3	CO_2					3.04	3.04	3.04
		CH_4					0.03	0.03	0.05
		N_2O					1.2E-05	1.2E-05	1.2E-05
Out-of-state	4	CO_2					9.13	9.13	9.13
		CH_4					0.08	0.08	0.11
		N_2O					2.2E-04	2.2E-04	2.2E-04
Out-of-state	***Total***	**CO_2**	**7.27**	**30.1**	**40.4**	**35.4**	**27.7**	**27.7**	**27.7**
		CH_4	**1.01**	**0.26**	**0.27**	**0.26**	**0.39**	**0.56**	**0.74**
		N_2O	**2.3E-04**	**5.5E-04**	**7.0E-04**	**6.0E-04**	**3.1E-04**	**3.1E-04**	**3.1E-04**
In-state	In-state	CO_2					0.07	0.10	0.10
		CH_4					0.17	0.20	0.20
		N_2O					2.0E-07	3.8E-07	3.8E-07
Out-of-state + in-state	***Out-of-state + in-state***	**CO_2**	**7.27**	**30.1**	**40.4**	**35.4**	**27.7**	**27.8**	**27.8**
		CH_4	**1.01**	**0.26**	**0.27**	**0.26**	**0.56**	**0.77**	**0.95**
		N_2O	**2.3E-04**	**5.5E-04**	**7.0E-04**	**6.0E-04**	**3.1E-04**	**3.1E-04**	**3.1E-04**
Combustion	Combustion	CO_2	211.1	155.6	144.1	138.6	116.6	116.6	116.6
		CH_4	1.6E-03	3.5E-03	5.6E-03	2.3E-03	2.3E-03	2.3E-03	2.3E-03
		N_2O	8.4E-03	9.0E-04	2.8E-03	2.3E-04	7.0E-04	7.0E-04	7.0E-04
Well-to-combustion total	***Well-to-combustion total***	**CO_2**	**218.4**	**185.6**	**184.5**	**174.1**	**144.4**	**144.4**	**144.4**
		CH_4	**1.02**	**0.26**	**0.28**	**0.27**	**0.57**	**0.77**	**0.95**
		N_2O	**8.6E-03**	**1.5E-03**	**3.5E-03**	**8.3E-04**	**1.0E-03**	**1.0E-03**	**1.0E-03**

Appendix E. Global Warming Potentials

Table E-1 lists the GWP factors used to generate the time series inventory. As described in section 1.2.2, the Climate Act requires the use of 20-year GWPs.

Table E-1. Global Warming Potentials

Source: IPCC (2013).

Species Name	Chemical Formula	GWP Values (AR4)		GWP Values (AR5)	
		20-year	100-year	20-year	100-year
Carbon dioxide	CO_2	1	1	1	1
Methane	CH_4	72	25	84	28
Nitrous oxide	N_2O	289	298	264	265
PFC-14	CF_4	5,210	7,390	4,880	6,630
PFC-116	C_2F_6	8,630	12,200	8,210	11,100
PFC-218	C_3F_8	6,310	8,830	6,640	8,900
PFC-318	$C4F_8$	7,310	10,300	7,110	9,540
Sulfur hexafluoride	SF_6	16,300	22,800	17,500	23,500
Nitrogen trifluoride	NF_3	12,300	17,200	12,800	16,100
HFC-23	CHF_3	12,000	14,800	10,800	12,400
HFC-32	CH_2F_2	2,330	675	2,430	677
HFC-125	CHF_2CF_3	6,350	3,500	6,090	3,170
HFC-134a	CH_2FCF_3	3,830	1,430	3,710	1,300
HFC-143a	CH_3CF_3	5,890	4,470	6,940	4,800
HFC-236fa	$CF_3CH_2CF_3$	8,100	9,810	6,940	8,060
Biogenic CO2	Biogenic CO_2	0	0	0	0

Appendix F. Greenhouse Gas Inventory Results

This appendix presents greenhouse gas emissions by sector for selected years, using the AR5 20-year Global Warming Potential. Table F-1 provides emissions data in thousand metric tons of carbon dioxide equivalent (CO_2e), including biogenic CO_2, which is reported separately for each sector where applicable.

Table F-1. Greenhouse Gas Emissions by Sector for Selected Years

Results are in MT CO_2e. All values include biogenic CO_2, which is also shown separately for each sector. Emissions are based on the AR5 GWP20.

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2019	2020	2021	2022
Electricity	Fuel Combustion	Coal	25,044	24,542	13,673	460	159	—	—
Electricity	Fuel Combustion	Distillate Fuel	473	1,026	274	163	77	89	454
Electricity	Fuel Combustion	Natural Gas	12,595	20,232	23,101	20,725	23,186	24,502	26,039
Electricity	Fuel Combustion	Petroleum Coke	—	166	539	—	—	—	—
Electricity	Fuel Combustion	Residual Fuel	25,452	10,781	847	171	100	400	773
Electricity	Fuel Combustion	Wood	68	591	444	602	611	576	525
Electricity Total, Fuel Combustion, Biogenic CO_2 only[a]			66	575	432	585	594	560	511
Electricity Total, Fuel Combustion			**63,631**	**57,339**	**38,878**	**22,121**	**24,134**	**25,566**	**27,791**
Electricity	Imported Fossil Fuels	Coal	6,741	3,639	3,886	161	69	—	—
Electricity	Imported Fossil Fuels	Distillate Fuel	153	336	92	52	25	29	144
Electricity	Imported Fossil Fuels	Natural Gas	11,523	20,385	25,412	16,299	18,146	18,983	20,023
Electricity	Imported Fossil Fuels	Petroleum Coke	—	34	112	—	—	—	—
Electricity	Imported Fossil Fuels	Residual Fuel	6,634	2,888	233	44	26	106	199
Electricity Total, Imported Fossil Fuels			**25,051**	**27,281**	**29,735**	**16,557**	**18,266**	**19,118**	**20,366**
Electricity	Net Electricity Imports—Fuel Combustion	All	914	6,919	8,114	4,700	3,700	5,301	5,384
Electricity	Electricity Imports—NJ—Fuel Combustion	All	—	2,067	2,337	3,113	2,829	3,116	3,325
Electricity Imports Total, Fuel Combustion, Biogenic CO_2 only[a]			6	2,227	2,456	3,113	2,829	3,116	3,325
Electricity Imports Total, Fuel Combustion			**914**	**8,986**	**10,451**	**7,814**	**6,529**	**8,417**	**8,710**
Electricity	Net Elec. Imports—Upstream Fossil Fuels	Coal	184	924	1,642	944	955	998	1,397

Table F-1. (continued)

Emissions Category(1	Emissions Category 2	Fuel Type	1990	2000	2010	2019	2020	2021	2022
Electricity	Net Elec. Imports—Upstream Fossil Fuels	Distillate Fuel	7	36	26	28	26	35	26
Electricity	Net Elec. Imports—Upstream Fossil Fuels	Natural Gas	59	1,027	2,131	1,381	1,271	1,592	1,828
Electricity	Net Elec. Imports—Upstream Fossil Fuels	Petroleum Coke	1	0	—	—	—	—	—
Electricity	Net Elec. Imports—Upstream Fossil Fuels	Residual Fuel	19	56	12	0	1	1	2
Electricity	Elec. Imports—NJ—Upstream Fossil Fuels	Distillate Fuel	—	—	13	0	0	1	1
Electricity	Elec. Imports—NJ—Upstream Fossil Fuels	Natural Gas	—	3,528	2,439	1,682	1,465	1,659	1,836
Electricity	Elec. Imports—NJ—Upstream Fossil Fuels	Petroleum Coke	—	—	5	2	—	2	1
Electricity Imports Total, Upstream Fossil Fuels			**270**	**5,571**	**6,269**	**4,037**	**3,718**	**4,288**	**5,092**
Electricity Total			**89,866**	**99,177**	**85,333**	**50,528**	**52,646**	**57,390**	**61,959**
Residential	Fuel Combustion	Coal	167	35	—	—	—	—	—
Residential	Fuel Combustion	Distillate Fuel	13,772	15,542	8,598	7,946	5,841	7,688	7,789
Residential	Fuel Combustion	Kerosene	743	987	420	242	232	185	167
Residential	Fuel Combustion	LPG	910	1,385	1,407	1,791	1,619	1,620	1,533
Residential	Fuel Combustion	Natural Gas	18,609	22,115	21,408	26,098	24,119	24,548	24,782
Residential	Fuel Combustion	Wood	4,977	10,800	2,715	4,630	2,878	3,060	3,417
Residential Total, Fuel Combustion, Biogenic CO_2 only[a]			3,923	8,514	2,140	3,650	2,268	2,412	2,694
Residential Total, Fuel Combustion			**39,178**	**50,864**	**34,547**	**40,708**	**34,689**	**37,101**	**37,688**
Residential	Imported Fossil Fuels	Coal	35	4	—	—	—	—	—
Residential	Imported Fossil Fuels	Distillate Fuel	4,408	5,027	2,857	2,502	1,845	2,465	2,438
Residential	Imported Fossil Fuels	Kerosene	185	252	110	60	58	47	41
Residential	Imported Fossil Fuels	LPG	391	606	624	752	682	692	641
Residential	Imported Fossil Fuels	Natural Gas	16,957	22,198	23,467	20,445	18,800	18,941	18,977

Table F-1. (continued)

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2019	2020	2021	2022
Residential Total, Imported Fossil Fuels			**21,975**	**28,088**	**27,059**	**23,760**	**21,384**	**22,145**	**22,097**
Residential Total			**61,153**	**78,952**	**61,606**	**64,468**	**56,073**	**59,247**	**59,784**
Commercial	Fuel Combustion	Coal	528	221	7	—	—	—	—
Commercial	Fuel Combustion	Distillate Fuel	6,735	6,674	4,368	3,622	2,786	3,663	3,663
Commercial	Fuel Combustion	Kerosene	113	399	65	31	23	18	16
Commercial	Fuel Combustion	LPG	258	393	418	535	602	665	645
Commercial	Fuel Combustion	Natural Gas	10,736	20,217	15,755	17,786	15,942	16,407	16,743
Commercial	Fuel Combustion	Residual Fuel	8,330	4,514	3,751	56	43	90	92
Commercial	Fuel Combustion	Wood	544	1,806	353	668	657	700	637
Commercial Total, Fuel Combustion, Biogenic CO_2 only[a]			429	1,423	278	527	518	552	502
Commercial Total, Fuel Combustion			**27,245**	**34,224**	**24,718**	**22,699**	**20,051**	**21,543**	**21,797**
Commercial	Imported Fossil Fuels	Coal	141	33	2	—	—	—	—
Commercial	Imported Fossil Fuels	Distillate Fuel	2,156	2,159	1,451	1,141	880	1,175	1,147
Commercial	Imported Fossil Fuels	Kerosene	28	102	17	8	6	5	4
Commercial	Imported Fossil Fuels	LPG	111	172	185	225	253	284	270
Commercial	Imported Fossil Fuels	Natural Gas	9,782	20,293	17,271	13,934	12,426	12,660	12,821
Commercial	Imported Fossil Fuels	Residual Fuel	2,146	1,195	1,019	14	11	24	24
Commercial Total, Imported Fossil Fuels			**14,363**	**23,953**	**19,946**	**15,321**	**13,576**	**14,146**	**14,265**
Commercial Total			**41,608**	**58,177**	**44,664**	**38,020**	**33,627**	**35,690**	**36,062**
Industrial	Fuel Combustion	Coal—Coking	3,446	—	—	—	—	—	—
Industrial	Fuel Combustion	Coal—Other	4,422	4,060	1,953	846	384	510	584
Industrial	Fuel Combustion	Distillate Fuel	1,283	924	625	633	658	585	591
Industrial	Fuel Combustion	Kerosene	104	63	229	51	160	45	34
Industrial	Fuel Combustion	LPG	29	105	16	14	15	21	25
Industrial	Fuel Combustion	Natural Gas	5,388	5,103	3,987	4,630	4,427	4,597	4,536
Industrial	Fuel Combustion	Petroleum Coke	1,335	1,500	1,005	825	493	598	121
Industrial	Fuel Combustion	Residual Fuel	2,224	952	244	171	92	211	216
Industrial	Fuel Combustion	Special Naphthas	13	3	1	11	10	9	10
Industrial	Fuel Combustion	Wood	2,496	3,015	1,598	1,820	1,754	1,764	1,784
Industrial	Non-Energy Fuel Use	Asphalt and Road Oil	12	13	14	12	12	14	13
Industrial	Non-Energy Fuel Use	Coal—Coking	—	2,596	416	—	—	—	—
Industrial	Non-Energy Fuel Use	Coal—Other	20	34	19	15	8	11	12

Table F-1. (continued)

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2019	2020	2021	2022
Industrial	Non-Energy Fuel Use	Distillate Fuel	4	5	2	2	2	2	2
Industrial	Non-Energy Fuel Use	LPG	51	151	43	54	62	88	105
Industrial	Non-Energy Fuel Use	Lubricants	429	437	292	255	238	236	241
Industrial	Non-Energy Fuel Use	Lubricants (Transportation)	445	453	394	296	252	283	310
Industrial	Non-Energy Fuel Use	Misc. Petroleum Products	232	536	118	147	140	140	150
Industrial	Non-Energy Fuel Use	Natural Gas	88	87	50	124	117	132	130
Industrial	Non-Energy Fuel Use	Petroleum Coke	40	12	—	—	—	—	—
Industrial	Non-Energy Fuel Use	Special Naphthas	85	31	14	59	53	50	55
Industrial	Non-Energy Fuel Use	Waxes	33	36	14	8	7	9	10
Industrial Total, Fuel Combustion and Non-Energy Fuel Use, Biogenic CO_2 only[a]			2,400	2,898	1,536	1,750	1,686	1,696	1,716
Industrial Total, Fuel Combustion and Non-Energy Fuel Use			**22,179**	**20,116**	**11,035**	**9,974**	**8,885**	**9,303**	**8,929**
Industrial	Imported Fossil Fuels	Asphalt and Road Oil	602	664	744	610	624	720	646
Industrial	Imported Fossil Fuels	Coal	2,138	1,039	697	301	168	175	258
Industrial	Imported Fossil Fuels	Distillate Fuel	416	304	210	202	211	190	187
Industrial	Imported Fossil Fuels	Kerosene	26	16	61	13	40	11	8
Industrial	Imported Fossil Fuels	LPG	44	152	41	43	50	67	79
Industrial	Imported Fossil Fuels	Lubricants	165	171	116	97	90	91	91
Industrial	Imported Fossil Fuels	Lubricants (Transportation)	171	177	157	112	96	109	117
Industrial	Imported Fossil Fuels	Misc. Petroleum Products	60	142	32	38	36	37	38
Industrial	Imported Fossil Fuels	Natural Gas	5,100	5,355	4,547	3,861	3,676	3,777	3,698
Industrial	Imported Fossil Fuels	Petroleum Coke	275	309	210	163	98	120	24
Industrial	Imported Fossil Fuels	Residual Fuel	578	254	67	44	24	56	56
Industrial	Imported Fossil Fuels	Special Naphthas	49	18	8	34	31	29	32

Table F-1. (continued)

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2019	2020	2021	2022
Industrial	Imported Fossil Fuels	Waxes	18	20	8	5	4	5	6
Industrial Total, Imported Fossil Fuels			**9,642**	**8,621**	**6,898**	**5,522**	**5,148**	**5,388**	**5,239**
Industrial Total			**31,821**	**28,737**	**17,932**	**15,496**	**14,034**	**14,690**	**14,168**
Transp.—On-Road Motor Vehicles	Fuel Combustion	CNG	0	81	258	193	179	231	331
Transp.—On-Road Motor Vehicles	Fuel Combustion	Diesel	8,937	12,040	12,826	14,033	12,856	13,811	15,597
Transp.—On-Road Motor Vehicles	Fuel Combustion	Gasoline	51,275	61,559	55,678	50,288	39,950	42,437	41,251
On-road Transportation Total, Fuel Combustion, Biogenic CO2 only[a]			—	105	3,634	4,110	3,262	3,539	3,558
On-road Transportation Total, Fuel Combustion			**60,212**	**73,681**	**68,761**	**64,515**	**52,985**	**56,479**	**57,179**
Transp.—On-Road Motor Vehicles	Imported Fossil Fuels	CNG	0	51	250	46	42	49	101
Transp.—On-Road Motor Vehicles	Imported Fossil Fuels	Diesel	2,900	3,989	4,264	4,191	3,881	4,219	4,672
Transp.—On-Road Motor Vehicles	Imported Fossil Fuels	Gasoline	21,214	26,079	22,695	19,318	15,394	16,565	15,721
On-road Transportation Total, Imported Fossil Fuels			**24,114**	**30,119**	**27,209**	**23,555**	**19,318**	**20,833**	**20,494**
On-road Transportation Total			**84,327**	**103,800**	**95,970**	**88,069**	**72,303**	**77,311**	**77,673**
Transp.—Nonroad—Aviation	Fuel Combustion	Aviation Gasoline	62	44	15	33	28	30	31
Transp.—Nonroad—Aviation	Fuel Combustion	Jet Fuel	5,835	5,107	6,450	7,311	3,624	5,286	6,762
Transp.—Nonroad—Railroad	Fuel Combustion	Distillate Fuel	123	488	349	576	470	541	608
Transp.—Nonroad—Marine/Boating	Fuel Combustion	Distillate Fuel	105	174	74	296	266	294	331
Transp.—Nonroad—Marine/Boating	Fuel Combustion	Gasoline	447	602	515	801	876	1,010	796
Transp.—Military	Fuel Combustion	Distillate Fuel	120	51	197	13	33	23	26
Transp.—Military	Fuel Combustion	Residual Fuel	121	36	-	-	-	-	-
Transp.—Bunker (Vessel)	Fuel Combustion	Residual Fuel	496	4,195	5,014	425	513	891	914
Transp.—Bunker (Aircraft)	Fuel Combustion	Jet Fuel	11,579	8,286	10,344	13,667	6,164	7,428	10,739
Transp.—Nonroad—Other	Fuel Combustion	Diesel	486	516	361	468	347	295	299
Transp.—Nonroad—Industrial/Commercial	Fuel Combustion	Gasoline	130	120	347	1,020	1,038	1,045	1,110
Transp.—Nonroad—Construction	Fuel Combustion	Gasoline	202	86	310	74	75	70	30
Transp.—Nonroad—Agricultural	Fuel Combustion	Gasoline	127	160	236	11	11	12	21
Transp.—Nonroad—Public Nonhighway	Fuel Combustion	Gasoline	295	48	49	14	13	12	12
Transp.—Nonroad—Miscellaneous/Unclassified	Fuel Combustion	Gasoline	189	32	21	4	4	4	230
Transp.—Nonroad—Lawn and Garden	Fuel Combustion	Gasoline	1,060	1,118	1,124	1,205	1,224	1,242	1,261

Table F-1. (continued)

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2019	2020	2021	2022
Transp.—Nonroad—Recreational Vehicle	Fuel Combustion	Gasoline	465	488	487	557	568	539	551
Transp.—Nonroad—Pipelines	Fuel Combustion	Natural Gas	259	405	823	1,642	1,468	1,955	2,183
Nonroad Transportation Total, Fuel Combustion, Biogenic CO_2 only[a]			—	5	199	309	297	313	323
Nonroad Transportation Total, Fuel Combustion			**22,100**	**21,957**	**26,715**	**28,116**	**16,720**	**20,679**	**25,903**
Transp.—Nonroad—Aviation	Imported Fossil Fuels	Aviation Gasoline	15	11	4	8	7	8	8
Transp.—Nonroad—Aviation	Imported Fossil Fuels	Jet Fuel	1,501	1,330	1,725	1,836	914	1,358	1,687
Transp.—Nonroad—Railroad	Imported Fossil Fuels	Distillate Fuel	40	158	115	172	142	165	182
Transp.—Nonroad—Marine/Boating	Imported Fossil Fuels	Distillate Fuel	32	54	23	85	77	86	94
Transp.—Nonroad—Marine/Boating	Imported Fossil Fuels	Gasoline	187	254	205	300	329	384	295
Transp.—Military	Imported Fossil Fuels	Distillate Fuel	37	16	62	4	10	7	7
Transp.—Military	Imported Fossil Fuels	Residual Fuel	31	9	—	—	—	—	—
Transp.—Bunker (Vessel)	Imported Fossil Fuels	Residual Fuel	127	1,109	1,360	109	132	233	233
Transp.—Bunker (Aircraft)	Imported Fossil Fuels	Jet Fuel	2,978	2,158	2,766	3,433	1,555	1,908	2,679
Transp.—Nonroad—Other	Imported Fossil Fuels	Distillate Fuel	153	164	116	137	103	88	87
Transp.—Nonroad—Industrial/Commercial	Imported Fossil Fuels	Gasoline	52	49	132	363	371	378	391
Transp.—Nonroad—Construction	Imported Fossil Fuels	Gasoline	82	35	117	27	27	25	11
Transp.—Nonroad—Agricultural	Imported Fossil Fuels	Gasoline	53	67	92	4	4	5	8
Transp.—Nonroad—Public Nonhighway	Imported Fossil Fuels	Gasoline	119	19	19	5	5	4	4
Transp.—Nonroad—Miscellaneous/Unclassified	Imported Fossil Fuels	Gasoline	76	13	8	1	1	1	81
Transp.—Nonroad—Lawn and Garden	Imported Fossil Fuels	Gasoline	425	449	420	423	431	443	439
Transp.—Nonroad—Recreational Vehicle	Imported Fossil Fuels	Gasoline	186	197	184	198	203	195	195
Transp.—Nonroad—Pipelines	Imported Fossil Fuels	Natural Gas	237	409	908	1,295	1,152	1,519	1,683
Nonroad Transportation Total, Imported Fossil Fuels			**6,332**	**6,501**	**8,256**	**8,400**	**5,461**	**6,808**	**8,083**
Nonroad Transportation Total			**28,431**	**28,458**	**34,971**	**36,515**	**22,180**	**27,487**	**33,987**
Transportation Total			**112,758**	**132,258**	**130,941**	**124,585**	**94,483**	**104,798**	**111,660**
Oil and Gas Systems	Fugitive Emissions	All	16,771	15,998	17,812	13,741	13,406	13,205	13,367
Grand Total (AR5 GWP20)			**353,977**	**413,298**	**358,289**	**306,839**	**264,269**	**285,020**	**297,000**

[a] Biogenic CO_2 results by sector for electricity, residential, commercial, and industrial reflect combustion of wood, while results for transportation sectors reflect biofuels, such as ethanol and biodiesel.

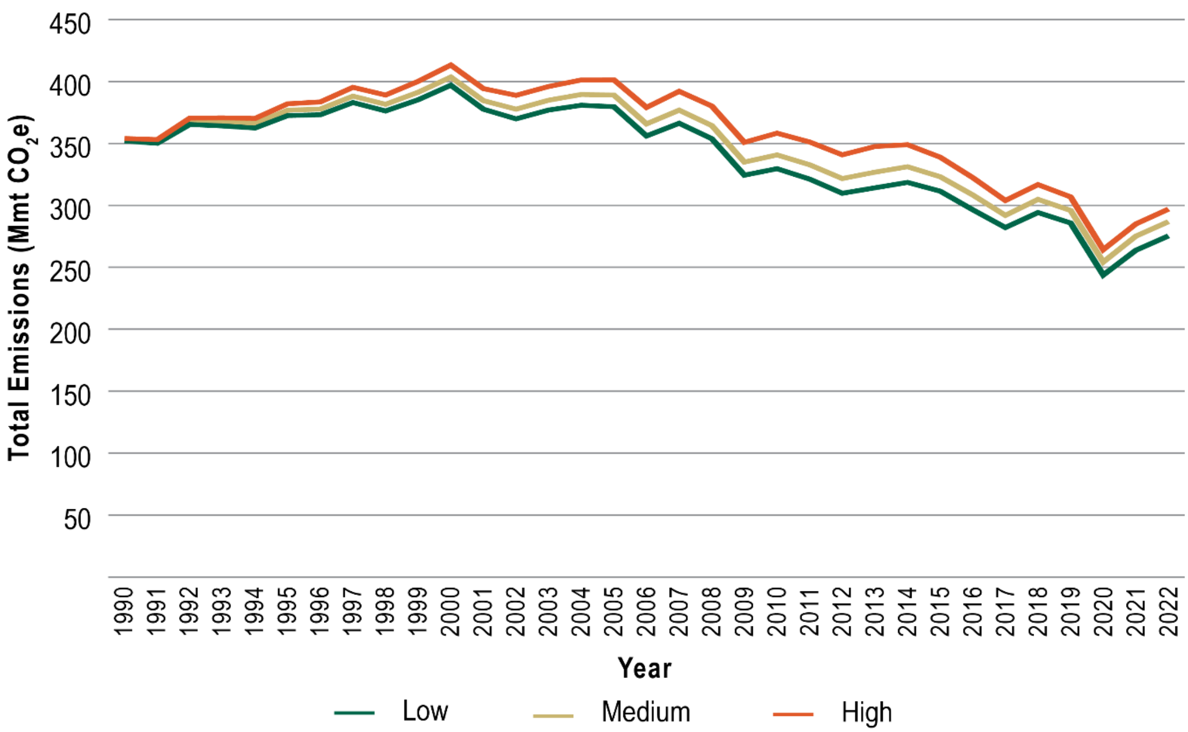
Appendix G. Results under Alternative Inventory Settings

G.1 Upstream Natural Gas Emission Factors

Figure G-1 tests the sensitivity of various natural gas approaches (described in section 2.2.1.1) on total NYS energy emissions. The default inventory uses the High natural gas upstream emission factor approach, which results in a total of 297 MMT CO_2e total emissions for 2022. By comparison, the Mid approach yields 286.9 MMT CO_2e, 3.4% reduction from the High approach. The Low approach results in 275.4 MMT CO_2e, a -7.3% reduction from the High approach.

Figure G-1. Total New York State Energy Emissions by Upstream Natural Gas Approach, 1990–2022

Values in MMT CO_2e.

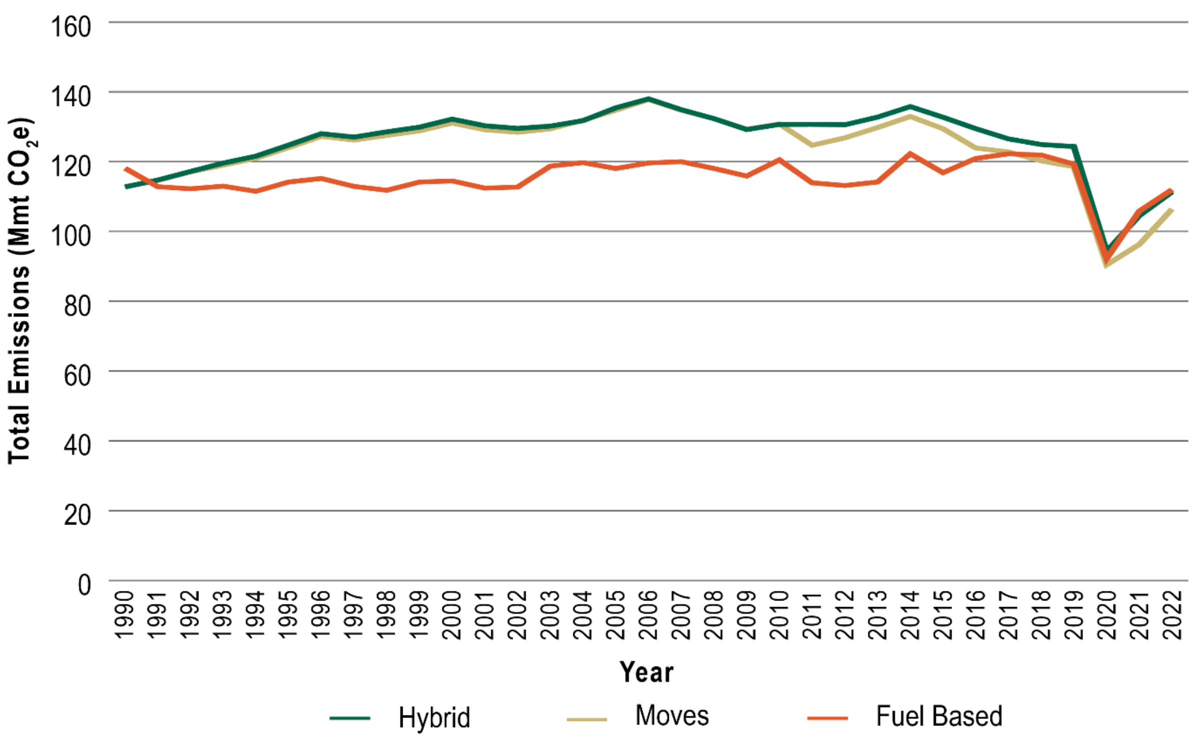


G.2 Transportation Method

Figure G-2 tests the sensitivity of total transportation sector emissions to the three on-road transportation input approaches available for the inventory, as described in section 2.1.5. The inventory uses the hybrid transportation assumptions by default. Throughout the time series, the hybrid and MOVES approaches align closely, while the fuel-based approach produces slightly lower estimates. However, in 2022, emissions values from all three approaches converge, with the hybrid approach estimating 111.4 MMT CO_2e, the MOVES approach at 106.4 MMT CO_2e, and the fuel-based approach estimating 112.0 MMT CO_2e.

Figure G-2. Total New York State Transportation Sector Energy Emissions by On-Road Transportation Input Approach, 1990–2022

Values in MMT CO_2e.

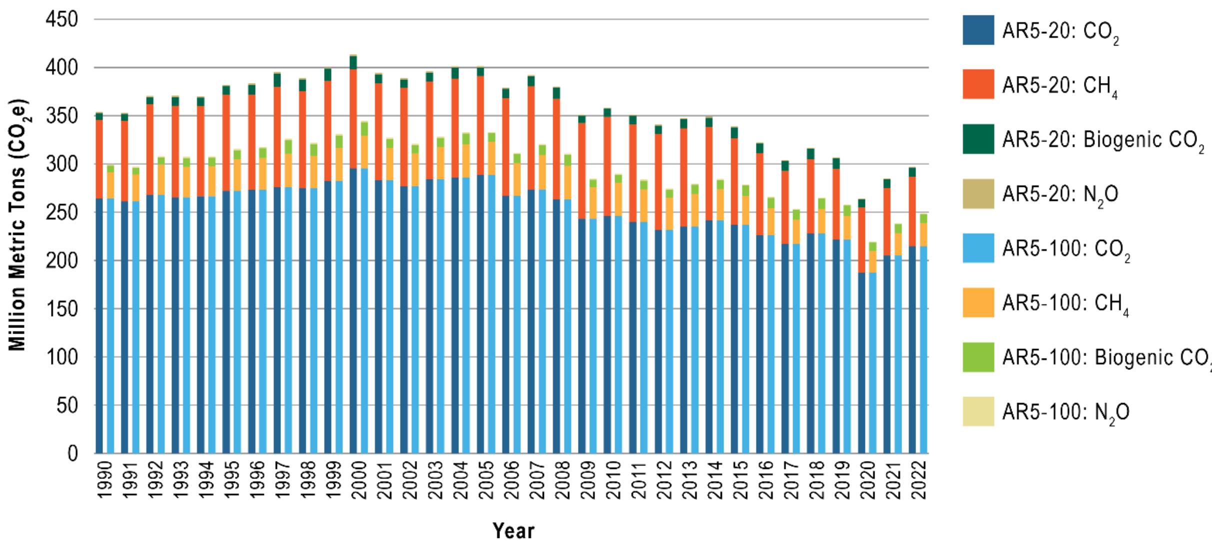


G.3 Global Warming Potential Characterization Factors

Figure G-3 shows the effects of different GWP approaches on total NYS energy emissions, categorized by gas type. By default, the inventory applies the reflected AR5 GWP20. The significant decrease in overall emissions from GWP20 to GWP100 results entirely from the reduction in methane GWP multipliers, which decline from 84 under the 20-year time horizon to 28 under the 100-year time horizon (AR5).

Figure G-3. New York State Energy Emissions by Greenhouse Gas

Total emissions presented for GWP20 and GWP100.

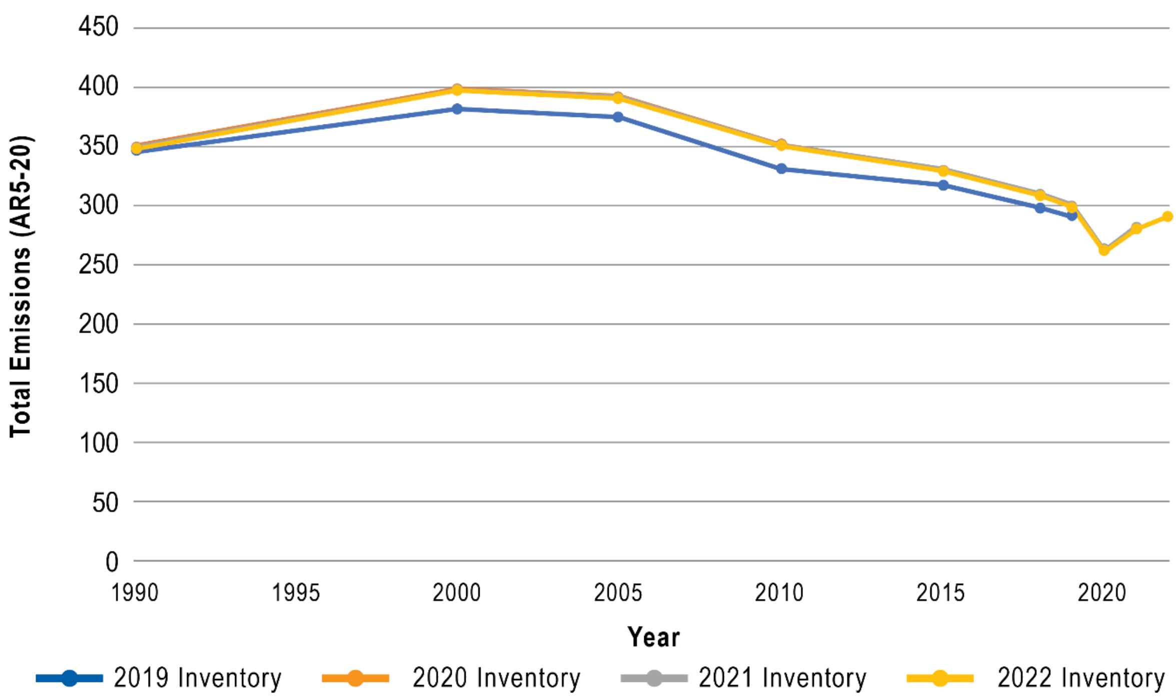


Appendix H. 2022 Data Year Results

Figure H-1 compares NYS energy emissions inventory results from the current 2022 inventory to with prior published inventories since the 2019 data year. Until 2010, the inventories showed slight differences in overall emissions, primarily due to updates in EPA emissions modeling profiles for transportation fuels, transitioning from MOVES2014b (used in the 2019 inventory) to MOVES3 (used in the 2020 inventory). Revisions to the underlying data for the oil and gas sector resulted in an annual decrease of approximately 1–2 MMT CO_2e across the time series (NYSERDA 2024).

Figure H-1. Change in Energy Emissions, 2019–2022 Inventory

Values in MMT CO_2e.



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New York State Energy Research and Development Authority

17 Columbia Circle
Albany, NY 12203-6399

toll free: 866-NYSERDA
local: 518-862-1090
fax: 518-862-1091

info@nyserda.ny.gov
nyserda.ny.gov

State of New York

Kathy Hochul, Governor

New York State Energy Research and Development Authority

Richard L. Kauffman, Chair | Doreen M. Harris, President and CEO