Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2021

Final Report | Report Number 23-27 | December 2023

NEW YORK STATE | NYSERDA

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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: 1990–2021

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

Macy Testani
Project Manager

Prepared by:

Eastern Research Group, Inc.

Concord, MA

NYSERDA Report 23-27 NYSERDA Contract 150851 December 2023

Notice

Preferred Citation

New York State Energy Research and Development Authority (NYSERDA). 2023. "Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990–2021." NYSERDA Report 23-27. Prepared by Eastern Research Group Inc, Concord, MA, USA. www.nyserda.ny.gov/About/Publications

Abstract

In July 2019, the New York State Legislature passed the landmark Climate Leadership and Community Protection Act. The Climate Act requires establishment of statewide limits to greenhouse gases (GHG) as a percentage of 1990 emissions (i.e., 60 percent by 2030 and 15 percent 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 the use of 20-year global warming potentials (GWP) and 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 the year 2021 and tracks GHG emission progress within New York State's 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 288.4 Mmt CO_2e in 2021. Emissions per capita peaked in 2000 but have since fallen to a low of 13.2 mt CO_2e per person in 2020 before rebounding to 14.5 mtCO_2e per person in 2021 (NYS, 2023). In-State emissions of CO_2 contributed 65 percent (186.3 Mmt CO_2e) to total GHGs in 2021.Combustion and upstream emissions for the transportation sector remained the largest source of energy sector emissions in the State in 2021, totaling 104.9 Mmt CO_2e, which saw a surge from 2020 as a result of the easing of the COVID-19 pandemic's travel restrictions. Residential emissions were the next largest contributing sector (60.3 Mmt CO_2e), followed by the electricity sector (58.0 Mmt CO_2e), the commercial sector (35.8 Mmt CO_2e), the oil and natural gas sector (14.9 Mmt CO_2e), and the industrial sector (14.6 Mmt CO_2e).

Keywords

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

Acknowledgements

This report describes the methods and results for the New York State GHG emissions inventory for the year 2021. This report was prepared by Eastern Research Group, Inc. (ERG) as 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 (NYSDEC) in development of this energy sector GHG inventory.

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Abbreviations

AR4	Fourth Assessment Report
AR5	Fifth Assessment Report
AVFT	Alternative Fuel Vehicle and Technology
B0	conventional diesel
B5	5% diesel
bbl	barrels
Btu	British thermal unit
CARB	California Air Resources Board
CC	carbon content
CH_4	methane
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
E10	gasoline containing up to 10% ethanol
E85	gasoline containing 70–85% ethanol
EIA	Energy Information Administration
ERG	Eastern Research Group, Inc.
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
g	gram
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
kg	kilogram
LPG	liquefied petroleum gas
ME	Maine
mmBtu	one million British thermal units
MMCF	one million cubic feet
MOVES	Motor Vehicle Emission Simulator (model)
MT	metric ton
MW	megawatt

N_2O	nitrous oxide
NAS	National Academy of Sciences
NEI	National Emissions Inventory
NETL	National Energy Technology Laboratory
NYISO	New York Independent System Operator
NYS GHG	New York State greenhouse gas
NYS	New York State
NYSDEC	New York State Department of Environmental Conservation
NYSERDA	New York State Energy Research & Development Authority
OPGEE	The Oil Production Greenhouse Gas Emissions Estimator
PADD	Petroleum Administration for Defense District
PRELIM	The Petroleum Refinery Life Cycle Inventory Model
SEDS	State Energy Data System
SIT	State Inventory Tool
U.S. EPA	United States Environmental Protection Agency
U.S. GHG	United States greenhouse gas
VIUS	Vehicle Inventory and Use Survey
VMT	vehicle miles traveled

Executive Summary

In July 2019, the New York State Legislature passed the landmark Climate Leadership and Community Protection Act. The Climate Act requires establishment of statewide limits to greenhouse gases (GHG) as a percentage of 1990 emissions (i.e., 60 percent by 2030 and 15 percent 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 the use of 20-year global warming potentials (GWP) and 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 the year 2021 and tracks GHG emission progress within New York State's 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 288.4 Mmt CO_2e in 2021. Emissions per capita peaked in 2000 but have since fallen to a low of 13.2 mt CO_2e per person in 2020 before rebounding to 14.5 mt CO_2e per person in 2021 (NYS, 2023). In-State emissions of CO_2 contributed 65 percent (186.3 Mmt CO_2e) to total GHGs in 2021.

Figure ES-1. Total In-State and Out-of-State Energy Emissions, Per Capita Emissions, and 2021 GHG Makeup, Mmt CO_2e for New York State

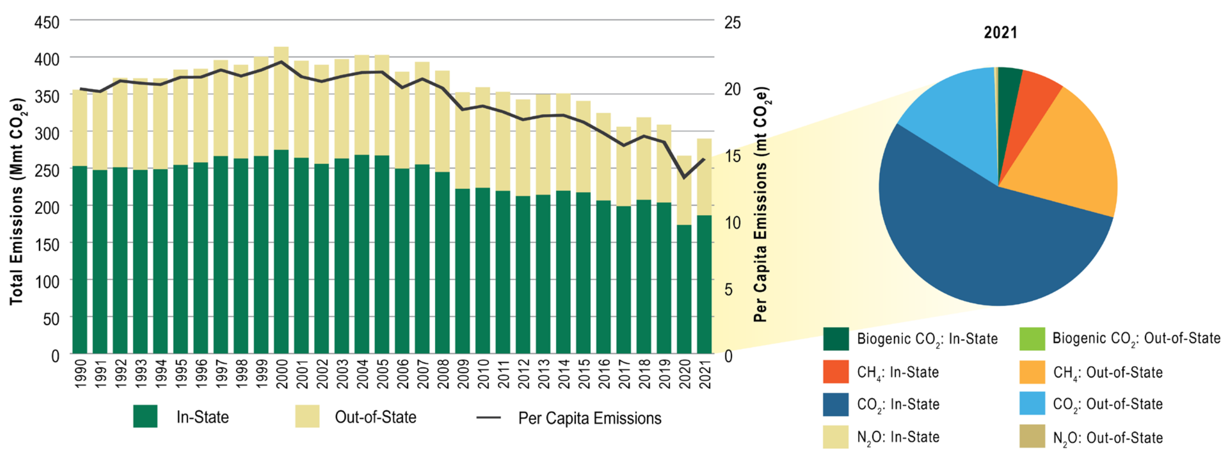
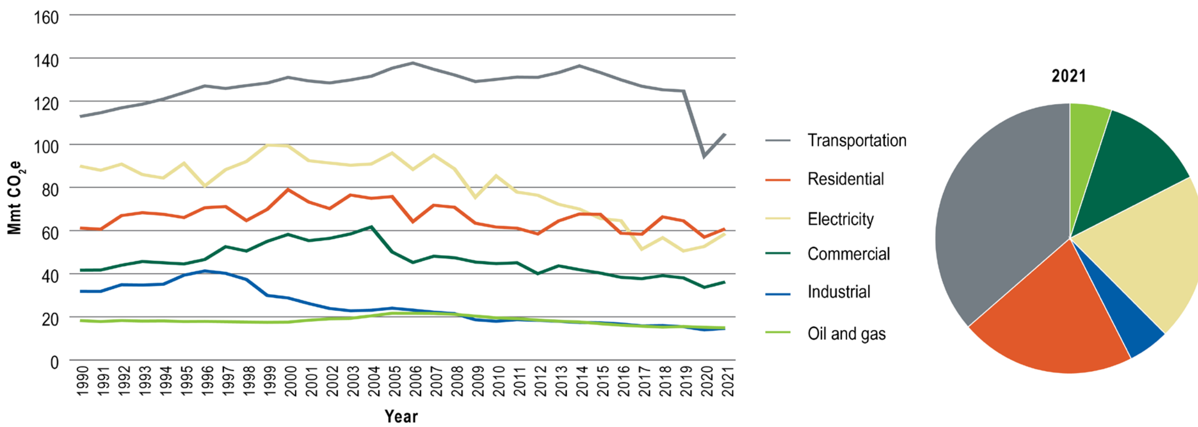


Table ES-2. Total In-State and Out-of-State Energy Emissions (Mmt CO_2e) for New York State

Emission Category	1990	2000	2005	2010	2015	2019	2020	2021
In-State	252.8	274.7	267.3	223.5	217.4	203.6	173.4	186.3
Out-of-State	102.9	139.0	135.4	135.7	123.4	105.1	92.9	102.1
Total	355.7	413.7	402.7	359.2	340.8	308.7	266.3	288.4

Combustion and upstream emissions for the transportation sector remained the largest source of energy sector emissions in the State in 2021, totaling 104.9 Mmt CO_2e, which saw a surge from 2020 as a result of the easing of the COVID-19 pandemic's travel restrictions. Residential emissions were the next largest contributing sector (60.3 Mmt CO_2e), followed by the electricity sector (58.0 Mmt CO_2e), the commercial sector (35.8 Mmt CO_2e), the oil and natural gas sector (14.9 Mmt CO_2e), and the industrial sector (14.6 Mmt CO_2e).

Figure ES-2. New York State Energy Emissions, by Sector, Mmt CO_2e



1 Introduction

In July 2019, the New York State Legislature passed the landmark Climate Leadership and Community Protection Act. The Climate Act requires establishment of statewide limits to greenhouse gas (GHG) emissions as a percentage of 1990 emissions (i.e., 60 percent by 2030 and 15 percent 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 the use of 20-year global warming potentials (GWP) and 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.

The Climate Act also requires preparation of 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 the year 2021.

1.1 Objectives

The objective of this study is to update New York State's energy sector GHG emissions inventory to provide the input required by the Climate Act. This updated inventory tracks GHG emission progress within New York State (NYS)'s 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

The NYS energy sector GHG Inventory approach as documented in this report is for calendar years 1990–2021. Emissions are estimated on an annual basis (i.e., metric tons/year). The following describes the NYS energy sector GHG Inventory geographic domain and spatial resolution:

- The New York State greenhouse gas (NYS GHG) Inventory includes all energy sector GHG emissions emitted from sources located and operating within State boundaries.
- The NYS 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 how boundaries are established for the upstream imported fossil fuels and electricity, respectively.

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 to carbon dioxide equivalent (CO_2e). CO_2e is calculated by multiplying the individual GHG species by their 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 included as an optional sensitivity analysis in the NYS energy sector GHG Inventory. Specific GWP characterization factors are listed in appendix E.

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 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 Intergovernmental Panel on Climate Change (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 current 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, ERG reviewed the previous NYS GHG Inventory as well as the United States (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 (U.S. EPA, 2023c)

These three inventories are bottom-up inventories that were developed using emission factors, activity data, and process-based models. A summary of the review findings and approach decisions is provided in appendix A. ERG completed a similar review for sources relevant for upstream fuel cycle emissions from imported fossil fuels, which is also summarized in Table 16, Table 20, and Table 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 methods described below were used to estimate emissions occurring within NYS for the entire 1990–2021 time 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 Intergovernmental Panel on Climate Change (IPCC). This approach was also adopted by the latest United States greenhouse gas (U.S. GHG) Inventory (U.S. EPA, 2023c). The calculation of biogenic CO_2 emissions is described in detail below within each source category where relevant.

Appendix B: Fuel Carbon Contents and Combustion Emission Factors provides the fuel carbon contents, as well as CH_4 and N_2O emission factors used in the in-State energy sector inventory (see Table 25 and Table 26).

Example calculations for CO_2 and CH_4 emissions from combustion are shown below. Source category specific modifications are discussed in each section where appropriate.

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

where,

$CO_{2,Total,y}$	= Total annual CO_2 emissions (metric tons, or 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 unit [Btu])
$CC_{f,y}$	= Carbon content of fuel *f* for year *y* (metric tons of C/billion Btu)
44/12	= ratio of the molecular weight of CO_2 to the molecular weight of C

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

$CH_{4,Total,y}$	= Total annual CH_4 emissions (metric tons) 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* (kilogram [kg] CH_4/trillion joules)
1055.06	= conversion factor from Btu to joules
1/1000	= conversion factor from kg to metric tons

2.1.1 Fuel Combustion: Electricity Generation

GHG emissions from electricity generation fuel combustion are estimated using State-level activity data from the Energy Information Administration's (EIA's) State Energy Data System (SEDS) (EIA, 2023a) 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 (U.S. EPA, 2023c). Methane and N_2O emissions are estimated using U.S.-specific emission factors also from the latest U.S. GHG Inventory (U.S. EPA, 2023c). 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.

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

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

2.1.2 Fuel Combustion: Residential

GHG emissions from residential fuel combustion are estimated using state-level activity data from SEDS (EIA, 2023a) 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 (U.S. EPA, 2023c). Methane and N_2O emissions are estimated using U.S.-specific emission factors from the latest U.S. GHG Inventory (U.S. EPA, 2023c). 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, 2023a) 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 (U.S. EPA, 2023c). Methane and N_2O emissions are estimated using U.S.-specific emission factors from the latest U.S. GHG Inventory (U.S. EPA, 2023c). 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, 2023a).

The SEDS industrial sector distillate fuel oil sales data consist of four components: industrial space heating and farm use, oil company use, off-highway use, and all other uses. It should be noted that the oil company use-sales data (SEDS data series "DFOCP") are relatively small, and all other use-sales data (SEDS data series "DFOTP") are assumed to be zero beginning in 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 (U.S. EPA, 2023c). Methane and N_2O emissions are estimated using U.S.-specific emission factors from the latest U.S. GHG Inventory (U.S. EPA, 2023c).

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 are tracked separately from those used for energy consumption in emissions calculations. Non-combustion use fractions and fuel storage fractions are from EPA's State Inventory Tool (SIT) (U.S. EPA, 2023d). Only CO_2 is tracked for nonenergy fuel use from industrial sectors, consistent with the U.S. GHG Inventory (U.S. EPA, 2023c).

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

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

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

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*

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

where,

$CO_{2,Total,y}$	= Total annual CO_2 emissions (metric tons) 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* (metric tons of C/billion Btu)
44/12	= ratio of the molecular weight of CO_2 to the molecular weight of C

The equation above also applies to calculating CO_2 emissions for non-energy purposes.

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

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

where,

$CH_{4,Total}$	= Total annual CH_4 emissions (metric tons) 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* (kilogram [kg] CH_4/trillion joules)
1055.06	= conversion factor from Btu to joules
1/1000	= conversion factor from kg to metric tons

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

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

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

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

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

While the following calculation reflects CO_2 emissions from non-energy fuel use.

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

2.1.5 Fuel Combustion: Transportation—On-road Motor Vehicles

On-road motor vehicles produce emissions of CO_2, CH_4, and N_2O 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, 5% biodiesel (B5), compressed natural gas (CNG), and gasoline containing 70–85% ethanol (E85).

Multiple data sources are available to characterize the emissions from on-road motor vehicles across the time series. Three methods were employed to estimate emissions from on-road motor vehicles, each described below:

1. Estimates of combustion emissions calculated from the U.S. EPA's MOtor Vehicle Emission Simulator (MOVES) model with NYS-specific parameters developed by ERG.
2. Estimates of combustion emissions calculated based on fuel consumption data from EIA SEDS.
3. Estimates of combustion emissions calculated using a hybrid approach of fuel consumption data and reported emissions calculated using MOVES for the EPA National Emissions Inventory (NEI).

For this inventory, NYSERDA and NYSDEC chose to implement the hybrid approach discussed in the third method.

Additionally, characterizing the quantity of blended biofuels (i.e., ethanol and biodiesel) varies by data source. EPA MOVES uses a volumetric assumption that varies by year, while SEDS tracks the consumption of biofuels for transportation by state for ethanol (SEDS data series “EMTCB”) and biodiesel (SEDS data series “BDACB”). SEDS reports CO_2 emissions from ethanol and biodiesel as biogenic CO_2. Users can select the choice of biofuels activity data can in the inventory separately from the three methods described above. For this inventory, NYSERDA and NYSDEC use SEDS data to characterize the biogenic portion of blended fuels. In 2021, the biogenic portion is 7.0% and 5.5% (energy basis) for gasoline and diesel, respectively.

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

The July 2023 release of U.S. EPA’s MOVES model (version MOVES3, database version movesdb20221007) (U.S. EPA, 2022) is used to estimate on-road GHG emissions in NYS (NYSERDA, 2019a).

MOVES is U.S. EPA’s state-of-the-science emissions modeling system for estimating criteria and GHG pollutants from on-road motor vehicles. The underlying data in MOVES are peer reviewed and based on analysis of millions of emissions test results, as well as many instrumented vehicle and telematics activity studies that produced second-by-second driving schedules, hourly speed distributions, temporal patterns of vehicle miles traveled (VMT), and more. U.S. EPA uses MOVES for its GHG rulemakings for motor vehicles.

A major benefit of using MOVES rather than other approaches is that MOVES allows an emission inventory calculation of GHG pollutants from on-road fuel combustion (i.e., CO_2, CH_4, and N_2O) all under one model. While a calculation of CO_2 based on fuel sales is a valid approach, it does not readily provide policy makers with detailed breakouts of the CO_2 emissions by fuel type, vehicle class, vehicle model year, or geographic areas (i.e., counties) contributing to the statewide totals. Additionally, because the location of the fuel sales might not match the location of combustion, and therefore CO_2 emissions, fuel purchased outside of NYS might not be properly accounted for in a fuel sales approach. Using MOVES for GHG emission inventories also presents an opportunity to begin shifting toward consolidating on-road emission modeling input data across different State regulatory use cases (e.g., shared MOVES inputs for State Implementation Plans, transportation conformity, GHG analysis, data submittals for NEI).

MOVES estimates 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. The model estimates N_2O emissions from N_2O emission rates in units of grams per hour (running exhaust) and grams per start (start exhaust) derived from emissions tests measured on the Federal Test Procedure supplemented by U.S. GHG Inventory N_2O emission rates (U.S. EPA, 2015).

Additional details on MOVES settings and specific data inputs are provided in Appendix C: MOVES Model.

2.1.6.1 EIA SEDS Fuel Consumption Method (Method 2)

Under the Fuel Consumption method, data for emissions from on-road fuel combustion are estimated using State-level activity data from SEDS (EIA, 2023a) for motor gasoline and diesel. Motor gasoline ("MGMFP") reflects highway fuel use. Data for diesel uses the SEDS series "DFONP" for on-highway use. E85 is not reported separately in this method.

Carbon dioxide emissions for the full-time series are estimated using U.S.-specific carbon content data from the latest U.S. GHG Inventory (U.S. EPA, 2023c). Methane and N_2O emissions are estimated using on-road emission factors from the IPCC (2006a) (Table 26).

2.1.6.2 Hybrid Approach

Under the hybrid approach, emissions data for on-road fuel combustion sourced from U.S. EPA's NEI are combined with ERG MOVES data to generate a full-time series. The NEI data for NYS is based on NYSDEC MOVES model and is available for 2011, 2014, 2017, 2020 and 2021; emissions data for interim years is extrapolated from known years, except for 2018 and 2019 which are carried forward from 2017. Prior years data are sourced from the ERG MOVES model described in section 2.1.5.1. Fuel-specific combustion activity from SEDS are scaled proportionally each year so that CO_2 emissions from these fuels are consistent with the emissions reported in the MOVES models, enabling fuel specific emissions estimates under this method.

2.1.7 Fuel Combustion: Transportation—Aviation

GHG emissions from fuel combustion from aviation activities are estimated using State-level data from SEDS for two fuel types: aviation gasoline and jet fuel (EIA, 2023a). This method was selected because it is consistent with the latest U.S. GHG Inventory (U.S. EPA, 2023c) and the 2006 IPCC Guidelines.

Prior to 2019, SEDS data for aviation fuels were assigned to states based on reporting by fuel suppliers. In 2019, this method was updated to use data from the Bureau of Transportation Statistics for years since 2010 to better reflect supply versus use of aviation fuels across state borders. For consistency across the time series for years before 2010, in the NYS GHG Inventory fuel use quantities for both NYS and New Jersey are summed together and then multiplied by the fraction of NYS passenger, freight, and mail revenue miles relative to the combined miles. Passenger, freight, and mail revenue mile data are sourced from the Bureau of Transportation Statistics (BTS, 2023).

The percentage of jet fuel consumed by international aircraft bunkers (i.e., international flights) was estimated based on the fraction of miles reported for international flights by the Bureau of Transportation Statistics. This percentage was excluded from NYS jet fuel consumption. Aviation gasoline is not consumed by international aircraft bunkers, so no further adjustment is needed. Aircraft bunkering emissions are included in section 2.1.11.

Carbon dioxide 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 (U.S. EPA, 2023c). Note that modern jet engines emit CH_4 at low power and idle operation, but these jet engines consume CH_4 at higher power modes. Over the entire range of operating modes, aircraft jet engines are net consumers of CH_4. As a result, the CH_4 emission factor for aircraft consuming jet fuel is zero (U.S. EPA, 2023c).

2.1.8 Fuel Combustion: Transportation—Railroads

GHG emissions from fuel combustion from railroad activities are estimated using State-level sales data from SEDS for distillate fuel oil (EIA, 2022). The railroad-use distillate fuel oil and residual fuel sales data have to date been reported under SEDS data series “DFRRP” and “RFRRP,” respectively.

However, EIA has since discontinued reporting of distillate fuel oil sales for railroad use, with their last update generated for 2020 sales. In the absence of alternative sources or proxy data, 2021 railroad distillate fuel oil sales were extrapolated using data from recent years. Historical values for distillate fuel oil sales to railroad activities were divided by annual total transportation sector distillate fuel oil sales (EIA data series “DFTRP”) to generate yearly contribution factors for the 2016-2020 period. These factors were then averaged and multiplied by total distillate fuel oil sales to the transportation sector for 2021 to yield an estimated distillate fuel oil sales value attributed to railroad activities. Furthermore, because the reported railroad-use residual fuel sales data for NYS are zero for 1990–2021, railroad use residual fuel is not included in the inventory. Carbon dioxide 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 (U.S. EPA, 2023c). The biogenic fraction of diesel (i.e., biodiesel content) is based on reported biodiesel consumption from SEDS (“BDACB”) relative to total diesel consumed for transportation. This fraction is applied for calculating biogenic CO_2 in all transportation categories where diesel is consumed.

2.1.9 Fuel Combustion: Transportation—Military Use

GHG emissions from transportation for military use are estimated using State-level data from SEDS for distillate and residual fuel oil (EIA, 2022). The military-use distillate fuel oil sales data are reported under SEDS data series “DFMIP,” while military use residual fuel oil sales data are reported under data series “RFMIP.” The same methods discussed in section 2.1.8 for estimating distillate fuel oil sales for railroad activities were applied to estimate distillate fuel oil sales for military use for 2021. Unlike railroad activities, residual fuel oil sales have historically been reported for military use, but this data series has also been discontinued by EIA. Residual fuel oil sales 2021 data were, therefore, extrapolated using similar methods developed to manage discontinued distillate fuel oil. Historical values for residual fuel oil sales to railroad activities were divided by annual total transportation sector distillate fuel oil sales (EIA data series “RFTRP”) to generate yearly contribution factors for the 2016–2020 period. Contribution factors were averaged and multiplied by total residual fuel oil sales to the transportation sector for 2021 to yield estimated residual fuel oil sales for military use. Carbon dioxide 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 (U.S. EPA, 2023c). 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

Vessel bunkering activities include all international marine transport activities. GHG emissions from vessel bunkering are estimated using state-level data from SEDS for distillate and residual fuel oil (EIA, 2022). The vessel bunkering distillate fuel oil sales data are reported under SEDS data series "DFBKP," while vessel bunkering residual fuel oil sales data used in this section are reported under data series "RFBKP." As of 2021, these data series have been discontinued, so distillate and residual fuel oil sales for vessel bunkering activities were calculated using the methods employed in sections 2.1.8 and 2.1.9, respectively.

Carbon dioxide 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 (U.S. EPA, 2023c). 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 activities include all international aviation transport activities. These emissions are tracked separately from those reported for domestic aviation described in section 2.1.6., which also describes the calculation for estimating the portion of NYS fuel consumed by international aircraft bunkers.

Carbon dioxide 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 (U.S. EPA, 2023c). This method was selected because it is consistent with the latest U.S. GHG Inventory (U.S. EPA, 2023c) 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 emissions of CO_2, CH_4, and N_2O. The distillate fuel oil sales data for off-highway use in this section are reported under SEDS data series "DFOFP." In order to avoid double counting, the off-highway distillate fuel oil sales quantities are subtracted from the overall industrial distillate fuel oil sales quantities (i.e., SEDS data series "DFICB") as described in section 2.1.4. As of 2021, these data series have been discontinued, so distillate fuel oil sales for other nonroad activities were calculated using the updated methods described in section 2.1.8.

Carbon dioxide 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 (U.S. EPA, 2023c). 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, 2023a). 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 non-highway 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 different SEDS data series that are spliced together: marine use from 1990–2014 and boating use from 2015 to present. In addition, the lawn and garden–use and recreational vehicle–use components are based on SEDS data series that were initiated in 2015; sales data for these two components were backcast for the remainder of the time series based upon NYS population (NYSOITS, 2022). For 2021, the Federal Highway Administration 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, 2021a; FHWA, 2021b).

Carbon dioxide 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 (U.S. EPA, 2023c). The emission factors are assumed to be for four-stroke, gasoline-powered equipment in each component. Public non-highway use and miscellaneous/unclassified use are assumed 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."

Carbon dioxide 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 (U.S. EPA, 2023c).

2.1.15 Oil and Gas Systems

Various processes and equipment associated with the oil and gas sector result in the release of CH_4, CO_2, and N_2O to the atmosphere.

The emissions estimation method for oil and gas systems relies on the methane estimates developed for the 1990–2021 NYS Oil and Gas Methane Inventory, a geospatially resolved, bottom-up inventory that was developed using identified best practices (NYSERDA, 2023). For the 2021 inventory, the NYS Oil and Gas Methane Inventory included additional source categories. 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 (U.S. EPA, 2023c).

To account for uncertainty in emissions estimates from bottom-up approaches, emissions estimates for natural gas systems utilize 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.

For oil systems, pollutant ratios are developed for four individual segments: exploration, production, transportation, and abandoned oil wells. For natural gas systems, pollutant ratios are developed for seven individual 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 NYS in 1990 and 1991 (EIA, 2023b). Petroleum refinery emissions are estimated using national-level refinery estimates developed for the U.S. GHG Inventory (U.S. EPA, 2023c). National-level estimates are scaled to NYS based on the ratio of state-to-national crude oil distillation capacity (EIA, 2023b).

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

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

where,

$CO_{2,EXP,NY}$ = Annual CO_2 emissions from oil exploration in NYS (metric tons)
$CH_{4,EXP,NY}$ = Annual CH_4 emissions from oil exploration in NYS (metric tons)
$CO_{2,EXP,US}$ = Annual CO_2 emissions from oil exploration in the United States (metric tons)
$CH_{4,EXP,US}$ = Annual CH_4 emissions from oil exploration in the United States (metric tons)

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

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

An example calculation for CH_4 emissions from petroleum refineries is:

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

where,

$CH_{4,NY}$ = Annual CH_4 emissions from refineries in NYS (metric tons)
$CH_{4,US}$ = Annual CH_4 emissions from refineries in the United States (metric tons)
$RefineryCapacity_{NY}$ = Crude oil distillation capacity for refineries in NYS (bbl/calendar day)
$RefineryCapacity_{US}$ = Crude oil distillation capacity for refineries in the United States (bbl/calendar day)

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

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 requirement necessitates incorporating upstream fuel-cycle factor data for these select fuel types. Table 2 shows the relevant fuel types considered for estimating emissions from upstream fuel cycle imports. For this inventory, “imported fossil fuel” emissions are defined as emissions from fuel extraction, processing, transportation, and distribution to the NYS boundary. The upstream fuel cycle does not include emissions associated with infrastructure construction and maintenance or manufacturing of equipment (e.g., buildings, roads, pipelines, motor vehicles, industrial machinery).

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

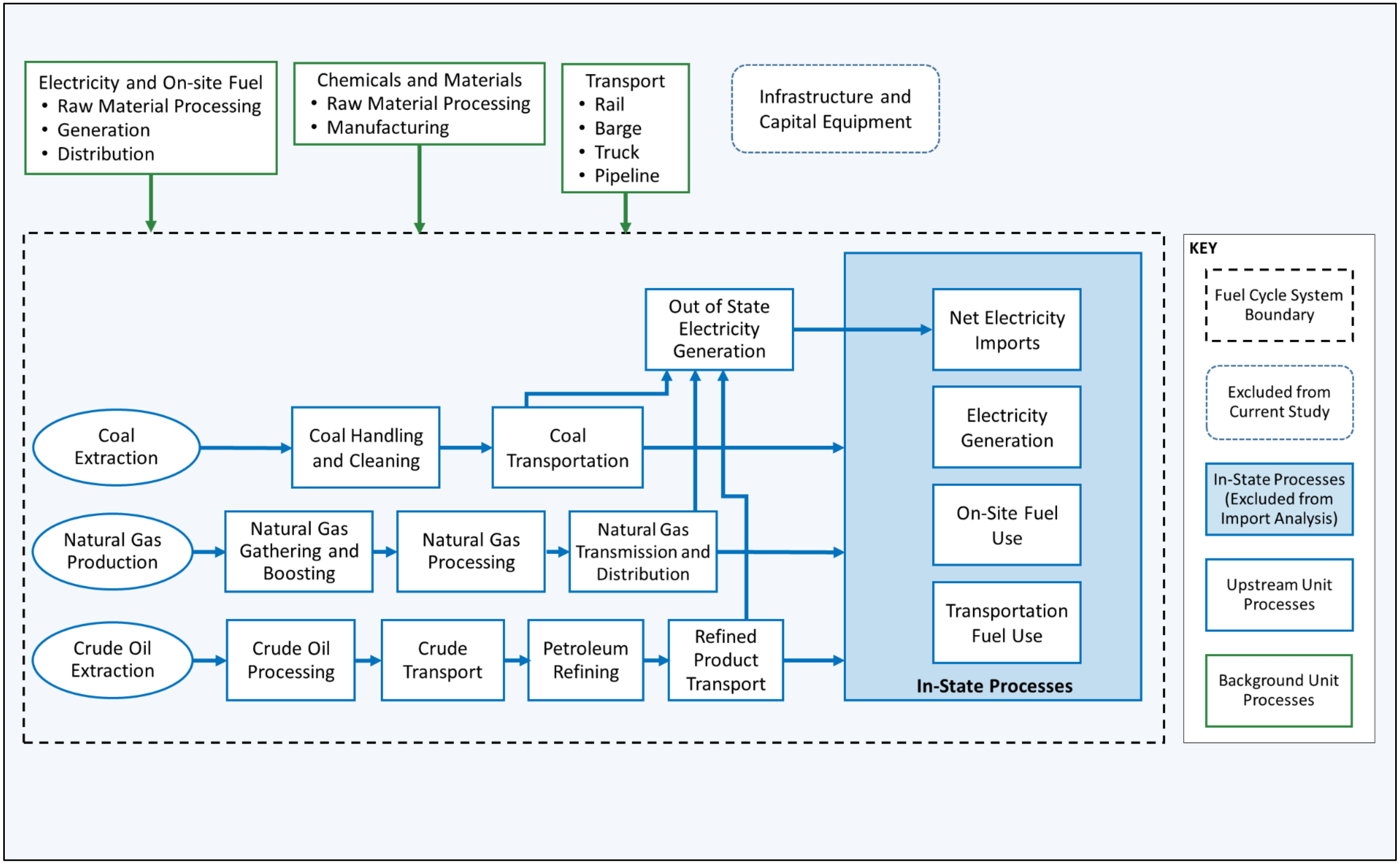
Fuel Type	Electric Power	Transportation	Commercial	Residential	Industrial
Coal	x		x	x	x
Distillate	x	x	x	x	x
Jet fuel		x			
Kerosene			x	x	x
LPG			x	x	x
Motor gasoline		x			x
Diesel		x			
Natural gas	x	x	x	x	x
Residual fuel	x	x	x		x
Other petroleum fuels[a]	x	x	x	x	x

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

Figure 1 depicts the system boundaries for the upstream fuel-cycle analysis. Upstream fuel cycle emissions for fossil fuels are accounted for in order to ensure compliance with the Climate Act. Inclusion of upstream fuel-cycle factors for non-fossil fuels (e.g., biofuels) is not required by the Climate Act, and these non-fossil fuels are excluded from the out-of-State upstream fuel-cycle analysis.

Calculations used to estimate upstream fuel-cycle emissions associated with imported fossil fuels for the 1990–2021 time series are described in detail in this section. To calculate upstream fuel-cycle emissions, upstream fuel-cycle emission factors for each fuel are multiplied by the total quantity of fuel consumed each year in NYS. For blended fuels, upstream fuel-cycle emission factors developed from the underlying models reflect the fossil-only portion of those fuels, and therefore, are only applied to the estimate of the non-biogenic content of fuels consumed in NYS.

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



2.2.16 Natural Gas Upstream Fuel Cycle Imports

The National Energy Technology Laboratory (NETL) Natural Gas model (NETL, 2019) assesses GHG emissions from natural gas extraction, processing, transmission, and distribution from U.S. natural gas basins. Upstream fuel cycle emissions for NYS are sourced from this bottom-up model in openLCA, an open-source life-cycle modeling software application. However, the model simply serves as a starting point; available empirical data addressing areas of uncertainty in the wider natural gas literature body are integrated into the NETL model framework to develop regionally specific emission factors unique to this inventory. Among the areas of uncertainty this approach sought to address are skewed emissions from low-producing conventional gas wells (known as “super-emitters”) and uncertainty around shale gas emissions, as well as discrepancies in natural gas emissions reporting between bottom-up inventories and top-down measurements (both discussed further in section 2.2.1.1). Adjustments are also made to the NETL model—which is reflective of 2016 conditions—to account for both changes in GHG emission intensity throughout the time series based on data from the U.S. GHG Inventory and variation in transmission distance to the New York State border based on the location of the natural gas source basins.

ERG identified five gas basins located in the southern United States/Gulf Coast and Appalachian region that provided the State conventional and tight natural gas from 1990–present and shale gas from 2007–present. Emissions from Canadian natural gas, relevant from 1990–2013, are modeled as the production-weighted average conventional mix of these five U.S. basins for NYS, as data from the Canadian GHG Inventory suggest 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 Annex 3.6 of the U.S. GHG Inventory (U.S. EPA, 2023e), from which the model’s emission factors are already derived. The U.S. GHG Inventory provides a comprehensive set of activity data at each stage of the natural gas supply chain and associated emissions on an annual basis, reaching back to 1990. Data in the inventory are representative of a U.S. national average, and while activity data are provided at a level of granularity that allows for manipulation of individual parameters, the NETL model does not share the same level of detail. Therefore, as opposed to using a process-level approach and manipulating individual parameters such as equipment quantity or number of wells, a higher-level approach was used to develop stage-level scaling factors to apply to CH_4 and N_2O emissions in the NETL model. Carbon dioxide takes both a stage-level and process-level approach, described later in this section.

Scaling factors are developed by first taking stage-level emissions provided by the U.S. GHG Inventory and dividing them by total natural gas produced in the United States on an annual basis (EIA, 2023c). For each stage (i.e., production through transmission), emissions for a given year are compared to 2016 emissions (the base year of the NETL model) per unit of natural gas produced. Below, Table 3 shows an example scaling factor calculation for the gathering and boosting stage, and Table 4 shows a list of all calculated scaling factors applied to the NETL model for 1990. Year 2016 was chosen as the baseline year for developing scaling factors in order to be consistent with the NETL model, which sources its data from the U.S. GHG Inventory and the Greenhouse Gas Reporting Program (GHGRP).

Table 3. Natural Gas Scaling Factor Calculation Example

	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

Scalar Equation: 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 (2023d).

Table 4. Natural Gas Scaling Factors Applied to NETL 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 distribution N_2O flare emissions.

New parameters were created in the NETL model for the calculated scaling factors and were directly applied to relevant GHG emissions in each stage. For CH_4, scaling factors were applied to emissions resulting from venting without flaring. In contrast, scaling factors for N_2O were applied to emissions resulting from flaring processes, which the U.S. GHG Inventory lists as the sole source of N_2O emissions. The inventory shows that CO_2 emissions predominantly stem from acid gas removal in Stage 3 (processing), so a process-level scaling factor was applied to CO_2 emissions in the NETL model. Carbon dioxide flaring emissions were also scaled at each relevant stage using the same flaring rates as N_2O. After applying the scaling factors, ERG generated emissions data using the NETL openLCA model for each relevant year in the time series.

The final parameter considered in manipulating the NETL model for NYS conditions was transmission pipeline distance. To model transmission, large cities located near each production basin were chosen as natural gas departure points. To avoid potential accounting for emissions associated with in-State movement of natural gas via pipelines, New York City is modeled as the destination for natural gas traveling from the five basins, as it is located along the State boundary. Table 5 lists the origin city for each basin and the transmission distance to New York City. Distribution distances are excluded from the imported fuel cycles as 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

The natural gas production basins responsible for the gas consumed by NYS are modeled as Gulf Coast, East Texas, Arkoma, Anadarko, and Appalachia (see Figure 2). These basins account for conventional, tight, and shale gas production and are highlighted as sources of gas consumed in NYS in a 2006 study prepared for NYSERDA (Rosenberg, Z. and Janney, A., 2006), as shown in Figure 3. While Figure 3 does not highlight East Texas as a contributing basin, this basin was modeled given its proximity to the Gulf Coast basin and the high volume of natural gas produced in Texas (EIA, 1994). Figure 3 also highlights the Western Canadian Sedimentary Basin as a source of gas. EIA data on the international and interstate movement of natural gas (EIA, 2023f) show that Canadian gas constitutes a significant portion of NYS net gas imports from 1992–2010, predominantly sourced from Alberta (CER, 2020). Since the NETL model only profiles U.S. basins, Canadian natural gas is modeled as a production-weighted average mix of these U.S. basins. EIA data on natural gas gross withdrawals and production (EIA, 2023d) begins to incorporate data on shale gas production starting in 2007. As such, shale gas production for the five basins is modeled for years 2007–present. Canadian gas constitutes a significant portion of NYS net gas imports up until 2010, at which point shale gas from Appalachia begins to replace Canadian imports.

Figure 2. Basins that Account for the Majority of United States Natural Gas Production

Source: Exhibit 2-2 of NETL Report Life Cycle Analysis of Natural Gas Extraction and Power Generation.

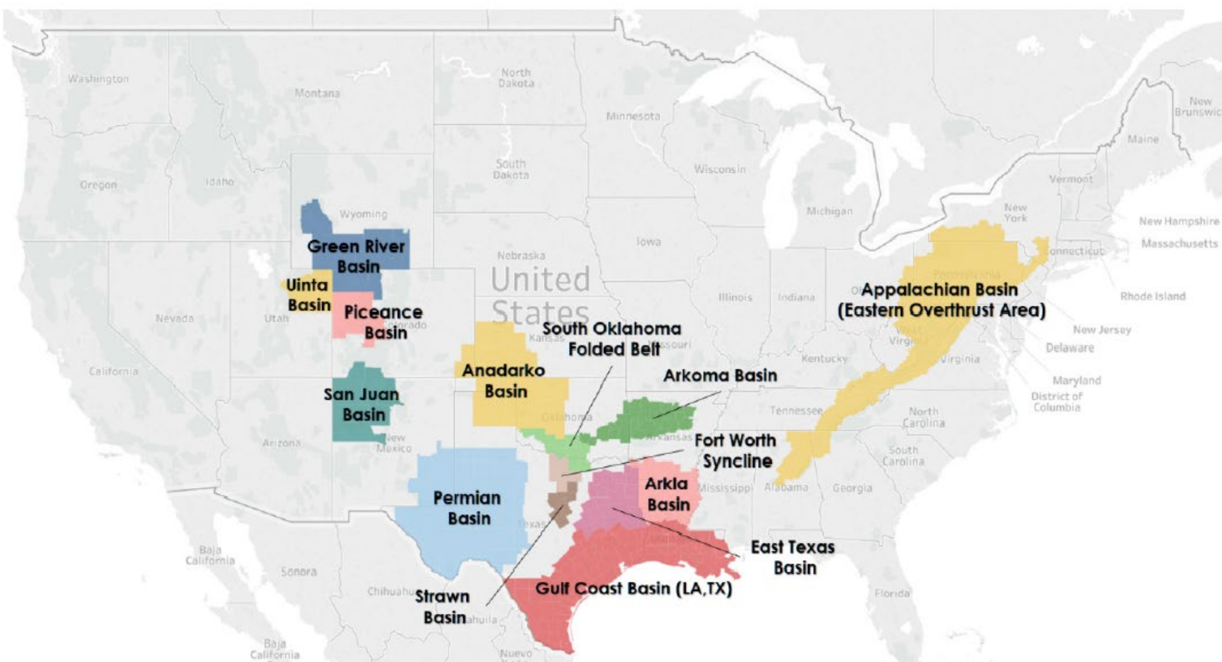
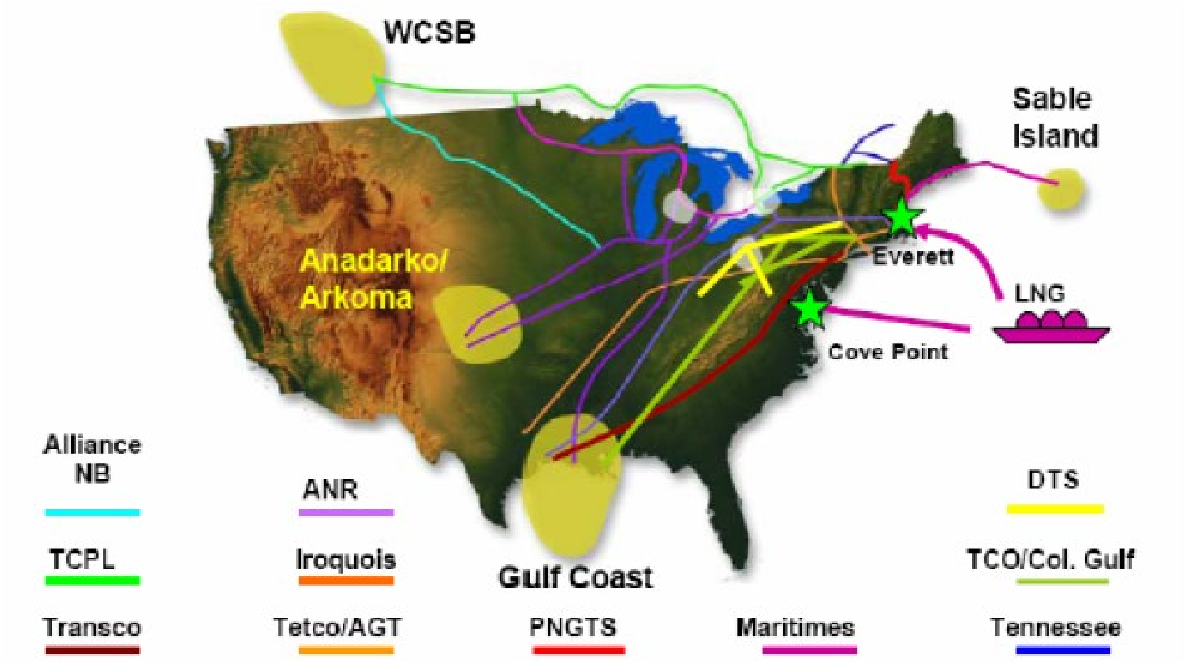


Figure 3. Source Basins for New York Natural Gas Consumed in 2006

Source: Exhibit IV-2 from 2006 ICF Report Petroleum Infrastructure Study.



To develop a New York State production-weighted aggregate emission rate for consumption of imported natural gas, the annual contribution of each basin and gas type to total gas consumed in NYS was first calculated. 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—were taken from the EIA's data on natural gas gross withdrawals and production (EIA, 2023d) and are displayed in Table 6. EIA data on shale gas production includes tight gas production, so an annual split between shale and tight gas was determined up until 2019 and extrapolated for future years (Table 7) from the EIA's Annual Energy Outlook (EIA, 2023e) and applied to the natural gas gross withdrawal data (EIA, 2023d) to separate the portion estimated to be from tight gas plays (Table 8). Figure 4 provides a visualization of the contribution of each basin and gas type to NYS consumption over the 1990–2021 time series.

Table 6. 2021 EIA Raw Natural Gas Production Data

State	Conventional (MMCF)	Shale/Tight (MMCF)
Texas	2,027,300	8,634,037
Oklahoma	594,770	1,932,590
Arkansas	68,983	378,295
Ohio	89,733	2,191,453
Pennsylvania	179,747	7,442,654
West Virginia	142,001	2,612,917
Virginia	15, 246	291

Table 7. Shale/Tight Gas National Split (2021)

Gas Type	Contribution (%)
Shale	91%
Tight	9%

Table 8. 2021 EIA Raw Natural Gas Production Data (expansion of Table 6 using Table 7)

State	Conventional (MMCF)	Shale (MMCF)	Tight (MMCF)
Texas	2,027,300	7,867,744	766,293
Oklahoma	594,770	1,761,068	171,522
Arkansas	68,983	344,720	33,575
Ohio	89,733	1,996,956	194,497
Pennsylvania	179,747	6,782,099	660,555
West Virginia	142,001	2,381,014	231,903
Virginia	15,246	265	26

Texas, Oklahoma, and Arkansas are representative of the Gulf Coast, East Texas, Anadarko, and Arkoma while the remaining states are representative of Appalachia. Using Figure 2, a basin's percent contribution to its respective state's production was estimated based off 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 represents 40% of Texas's total yearly production (Table 9). Table 10 provides a breakdown of 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	Percent of State Contribution (Based on Basin Area)[a]	Total Production (MMcuft)[b]	Percent 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 off EIA data for natural gas gross withdrawals and production (EIA, 2023d).

In 1990, Canadian gas accounted for 12.6% of total New York natural gas imports (EIA, 2023f) and in-State production accounted for 2.2% of total State consumption (NYSERDA, 2023), so the basins in Table 10 constitute around 85.2% of gas produced for New York State for 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, 2023).

Conventional extraction of natural gas from Appalachia is not characterized in the NETL model, as natural gas wells in that region often do not meet the GHGRP emissions reporting threshold of 25,000 metric tons CO_2e per year per facility (100-yr IPCC AR4 GWP) (NETL, 2019). Given the importance of the Appalachian basin to natural gas consumed in NYS, conventional gas production emissions from this basin were assessed using data from the NYSERDA Oil and Gas Methane Inventory (NYSERDA, 2023). 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).

This same approach was used 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. The same five basins and basin splits were used, a central point for each electricity region was chosen as the destination for the gas, and the transmission distance parameter was adjusted in the NETL model to reflect the distance from the origin city to the destination.

GHG emissions from natural gas systems are often reported as a methane emission rate, which reflects 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 (of which methane is the primary constituent) throughout the supply chain. Figure 5 displays the natural gas system CH_4 emission rate for basins serving NYS over the time series. The resulting aggregate NYS methane emission rate from out-of-State production through transmission to the NYS border is shown in Figure 6. 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

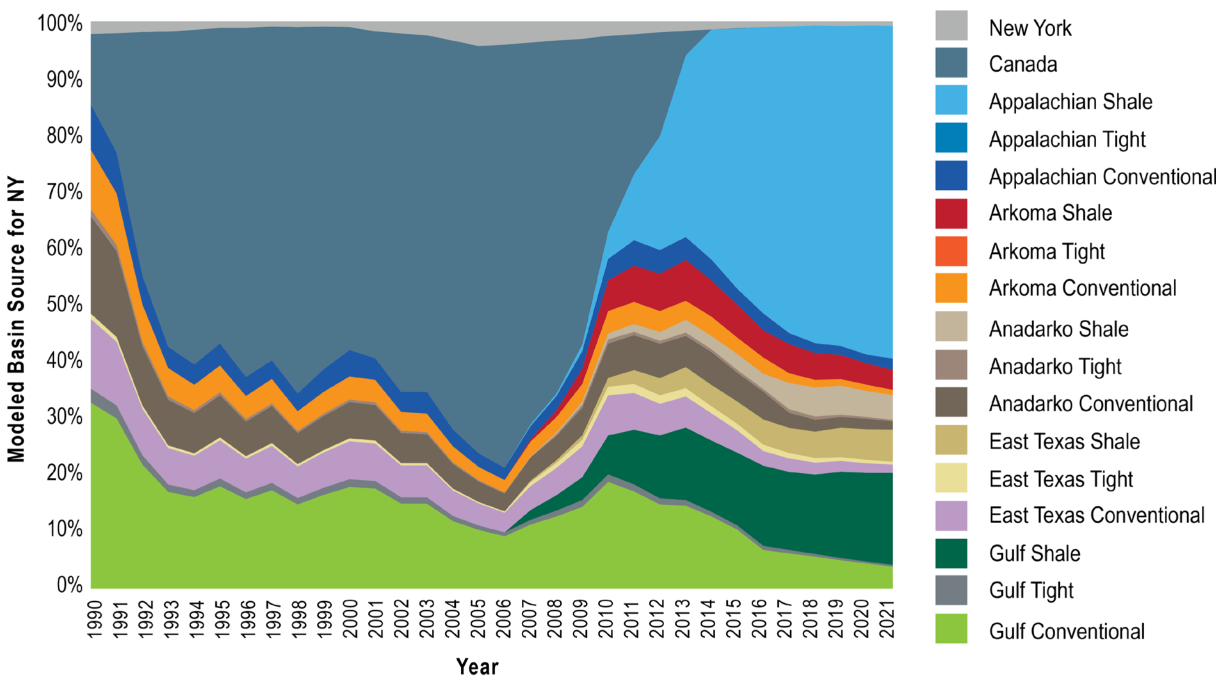


Figure 5. Natural Gas System Methane Emission Rates for Basins Serving New York State

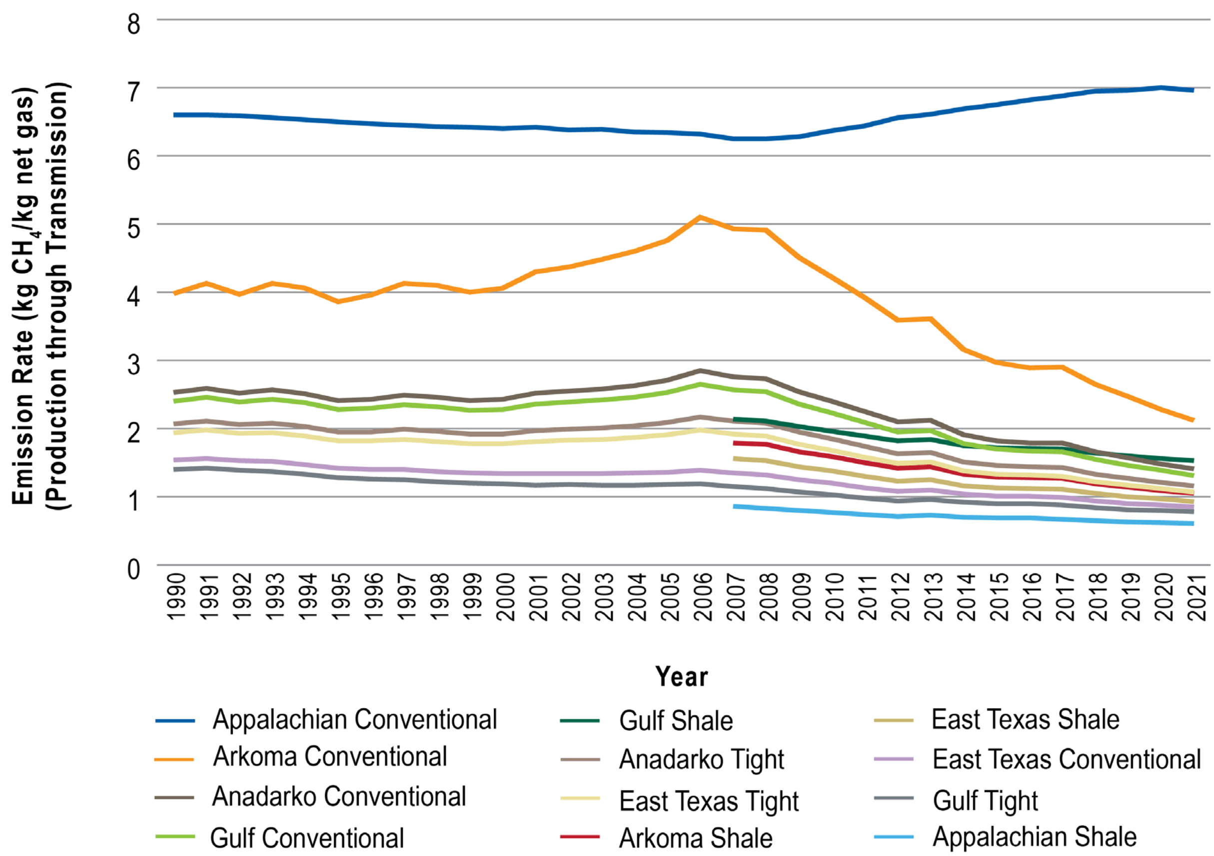


Figure 6. Natural Gas System Weighted Average Methane Emission Rates by Stage

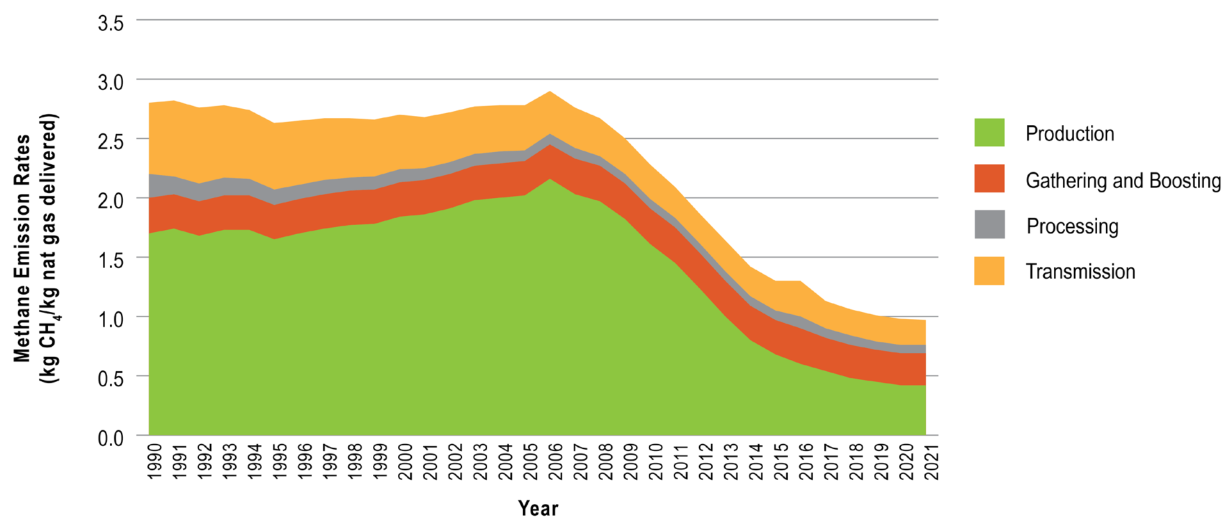


Table 12. Summary of Methane Emissions Rate by Basin and Stage

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 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 Aggregate	1990		1.7%	0.3%	0.2%	0.6%	2.8%

[a] Total may not equal sum of values across row due to rounding.

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

2.2.16.1 Natural Gas Upstream Sensitivity Analyses

Comparisons of results between recent top-down approaches using observations and atmospheric transport models and bottom-up inventories have identified significant differences in emission estimates, as shown in the National Academy of Sciences (NAS) report "Improving Characterization of Anthropogenic Methane Emissions in the United States" (National Academies of Sciences, Engineering, and Medicine, 2018). These differences are considered during the development of the NYS GHG Inventory, with a particular emphasis on one of the largest methane source categories identified in the NAS report: petroleum and natural gas systems.

Due to these discrepancies, ERG completed a targeted literature review of top-down versus bottom-up approaches for the natural gas and petroleum systems categories. Several studies suggest that using a strictly bottom-up approach has the potential to 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 percent or more (National Academies of Sciences, Engineering, and Medicine, 2018).

Additional critiques of bottom-up approaches include uncertainty and inaccuracy surrounding activity data and emission factors, often in reference to the U.S. GHG Inventory. NAS (2018) discusses how the scarcity of activity data on which to base the development of emissions estimates represents a significant source of uncertainty in the U.S. GHG Inventory, even though the U.S. GHG Inventory accounts for numerous emissions sources from petroleum and natural gas systems. In addition, the U.S. GHG Inventory may underestimate emissions because it fails to account for high emissions caused by abnormal operating conditions (Alvarez et al., 2018). Based on GHG measurements obtained via aircraft observation, Plant et al. (2019) notes that current urban inventory estimates of natural gas emissions are substantially low, either due to underestimates of leakage, lack of inclusion of end-use emissions, or some combination of both. To improve bottom-up approaches, NAS (2018) suggests using finer scale, geographically gridded inventories of national methane emissions to allow for better characterization and comparison of inventories and testing against top-down methane estimates.

Several studies discuss how a complementary, hybrid top-down/bottom-up approach can provide a more accurate emission estimate. For example, an Environmental Defense Fund study (Alvarez et al., 2018) employs a combined top-down/bottom-up approach by first integrating results of facility-scale, bottom-up studies to estimate methane emissions from the U.S. oil and natural gas supply chain, and then by validating these results using materials and 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 decreased in time, resulting in low-producing conventional wells. Despite their increasingly diminishing output, these low-producing wells (known as super-emitters) have been flagged in literature due to their disproportionately large emissions (Alvarez et al., 2018; Schneising et al., 2020; Zavala-Araiza et al., 2015).

ERG recognizes that a strictly bottom-up approach may result in underestimating GHG emissions; therefore, we made further adjustments to emission factors relating to the upstream natural gas fuel cycle to reflect the latest literature including top-down methods in the natural gas supply chain. Those adjustments are described below, reflecting both a mid-range and high-range approach.

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

The High sensitivity builds on the approach outlined in the Mid sensitivity through the addition of stage-level scaling factors. Literature surrounding natural gas methane emissions has highlighted discrepancies in reported estimates between inventory data and emissions monitoring (Alvarez et al., 2018). Alvarez and colleagues assess national methane emissions from the U.S. natural gas supply chain using facility-level estimates and validate these emissions with aircraft observations. Their measurements were estimated to be about 60 percent higher than the emissions reported in the U.S. GHG Inventory, suggesting that the Inventory may be underestimating methane emissions by not fully accounting for emissions released during abnormal operating conditions. The differences in emission estimates identified by Alvarez (2018) enabled the adjustment of emission factors for this analysis through the integration of stage-level scaling factors (Table 13).

Table 13. Alvarez (2018) Stage-Level Scaling Factors

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

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

Table 14 provides a summary of the parameters 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 2021 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, 2023). The default inventory in the NYS Oil and Gas Methane Inventory applies an Omara-derived emission factor for conventional natural gas production that reflects the 25th percentile of measured site-level production emissions (Omara et al., 2016). Just as in the upstream emissions calculations for conventional gas in the Appalachian basin, the in-State inventory is modified to use the 50th percentile emission factor from Omara (labeled as “Mid” in that inventory) under the Mid and High sensitivities calculated here. Only the emissions from conventional gas production, both low- and high-producing wells, are impacted by this sensitivity. No further adjustment to in-State emissions is made in the High sensitivity (i.e., no stage-level scaling factors are used) 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 (2021 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 25th percentile][a]	x			Production emission rate: 6.4%
Addition of Appalachian Conventional production emission rate [Omara 50th percentile]		x	x	Production emission rate: 15.2%
NETL Natural Gas Model Appalachian Shale production emission rate	x			Production emission rate: 0.08%
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]
NY aggregate out-of-State emission rate (%)	1.04%	1.47%	1.88%	Representative of production, gathering and boosting, processing, and transmission
NY aggregate well-to-burner emission rate (%)	1.46%	1.97%	2.38%	Includes all stages above as well as in-State production and consumption

[a] The Omara data supplements the NETL Natural Gas Model, which does not characterize Appalachian Conventional emissions.

[b] Top-down scaling factors applied from production through transmission for all basins and stages except Appalachian production. Example calculation: If original production emission rate is 1.34%, the top-down adjusted rate is 1.34% × 2.17 = 2.91%. This represents of an increase of 117% compared to the original rate.

Table 15. 2021 Emission Rates by Basin Across Sensitivities

Basin	Low Sensitivity	Mid Sensitivity	High Sensitivity
Anadarko Conventional	1.41%	1.41%	2.47%
Anadarko Shale	0.85%	0.85%	1.26%
Anadarko Tight	1.16%	1.16%	1.93%
Appalachian Conventional	6.96%	15.7%	15.9%
Appalachian Shale	0.61%	1.07%	1.22%
Arkoma Conventional	2.12%	2.12%	3.96%
Arkoma Shale	1.05%	1.05%	1.65%
East Texas Conventional	0.85%	0.85%	1.25%
East Texas Shale	0.93%	0.93%	1.43%
East Texas Tight	1.07%	1.07%	1.72%
Gulf Conventional	1.31%	1.31%	2.32%
Gulf Shale	1.53%	1.53%	2.78%
Gulf Tight	0.78%	0.78%	1.15%

Appendix D: Summary Tables of Fossil Fuel Emission Factors 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 below provides a summary of 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	Used the NETL Natural Gas Extraction model (NETL, 2019) available in the openLCA software as a starting point and source for activity data and emission factors for the following stages that constitute 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, 2023) take a similar approach to modeling natural gas production emissions, and the NETL model was used for the upstream fuel cycle approach as it contains readily available region-specific data. Available empirical data addressing areas of uncertainty in the wider natural gas literature body are integrated into the NETL model framework to develop regionally specific emission factors unique to this inventory. Among the areas of uncertainty this approach sought to address are skewed emissions from low-producing conventional gas wells (known as "super-emitters") and uncertainty around shale gas emissions, as well as discrepancies in natural gas emissions reporting between bottom-up inventories and top-down measurements. Annex 3.6 of the EPA's GHG Inventory (U.S. EPA, 2023e) was used to develop emissions scaling factors reflective of changes in emissions across the time series that were then applied to the NETL model and later adjusted further during sensitivity analysis.

Table 16 continued

Activity	Extraction and Processing of Natural Gas
Source category references	Transportation, electricity, residential, commercial, industrial.
Result	Two sets of emission factors for each main GHG (i.e., CO_2, CH_4, N_2O) are generated for gas produced for use as electricity and for use as fuel by consumers. However, natural gas distribution (after transmission) is excluded from the upstream emissions as it is captured in the in-State inventory (see section 2.1.14).
Technological scope	The NETL gas model accounts for upstream emissions from the point of production to the point of distribution, including blowdowns, flaring, and venting. Emissions associated with end-use combustion are not included. The model also includes emissions from any energy inputs into the process, such as emissions from production and consumption of diesel, natural gas, and electricity used for natural gas extraction.
Geographic scope	The NETL natural gas model reflects emissions from 14 gas-producing regions across the United States. The following basins are modeled to represent gas consumed by NYS from 1990–2020: Gulf Coast, East Texas, Anadarko, Arkoma, and Appalachian. Basin-specific parameters include emissions from equipment in the pre-processing stages, as well as the chemical composition of the natural gas, which differs between basins. Other differences between basins include how much gas is vented or flared. National parameters are used for stages after processing. The model is parameterized to NYS-specific transmission data.
Temporal scope	The NETL natural gas model reflects emissions and activities in 2016. Underlying data sources for major emission sources and activity data are released annually in the GHGRP and U.S. GHG Inventory, so the model can be updated in future years. NYSERDA's Oil and Gas Methane Emissions Inventory (NYSERDA, 2023) assumes that emission factors have remained constant since 1990 while production efficiency has fluctuated due to changes in activity data. Despite the lack of historical data in the NETL model, similarities to NYSERDA's Oil and Gas Methane Emissions Inventory are assumed regarding the consistency of emission factors and activity data over time. The U.S. GHG Inventory provides updated activity and emissions data over time. These data were used to develop emission scaling factors to apply to the model's 2016 values. Parameters for adjustment include flaring rates and venting rates, number of wells, equipment quantity, and energy inputs to the extraction process (e.g., electricity, diesel, and natural gas combustion amounts).
Alternate approaches considered	Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model includes emission factors for the extraction and processing of natural gas. However, the model does not enable parameterization for basin-specific characteristics, nor does it explicitly account for the full range of sources of emissions within the gas supply chain.
Notes	Two sensitivities are performed on the baseline approach outlined above to address discrepancies in national methane emissions from natural gas cited in literature. The first sensitivity applies the 50th percentile value of measured site-level conventional and shale gas emissions (Omara et al., 2016) to Appalachian production to address disproportionate releases from super-emitters. The second sensitivity builds on the first by applying top-down scaling factors (Alvarez et al., 2018) to other basins and natural gas stages[a] to address the difference in top-down vs. bottom-up methane emission estimates discussed in literature (Alvarez et al., 2018; Burnham, 2022).

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

2.2.17 Coal Upstream Fuel Cycle

The NETL Coal model, which profiles coal extraction through coal cleaning, was adapted to model conditions for coal production and distribution to NYS for the entire time series (NETL, 2020). To account for changes in underground coal mine methane over time, basin-level scaling factors are applied in Table 17 from data calculated using the U.S. GHG Inventory (U.S. EPA, 2019a). The U.S. GHG Inventory data estimates are developed using annual Mine Safety and Health Administration and facility-reported data from the GHGRP. The estimates account for ventilation emissions, drainage emissions, and avoided emissions from methane capture and use projects. All other mining emission sources are assumed 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, EIA Form 923 and Federal Energy Regulatory Commission (FERC) Form 423 (EIA, 2023l; FERC, 2011) were used. The forms specify the amount of coal received by New York State power plants as well as the coal mine condition and mine type. Based on the amount of coal coming from each state, a proportional contribution from each basin was determined. The NETL Coal model was then run 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 transport of coal from each relevant coal-producing state to NYS, data were taken from the EIA's Annual Coal Distribution Report (EIA, 2023g). The Coal Distribution Report specifies the amount of coal delivered to NYS from each state via a specific mode of transportation. The combination of quantity and mode was used to calculate a yearly percentage that was then applied to the utility data from forms FERC-423 and EIA-923. Table 18 shows a breakdown of coal transported by mode for each state to NYS in 1990. The same method was applied to all years in the time series.

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

State of Origin	Quantity (Short Tons)[a]	Percent Transport Via Truck[b]	Percent Transport Via Rail[b]	Percent Transport Via River Barge[b]	Percent 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 off 1990 FERC coal distribution data.

[b] Based off EIA coal distribution data.

Several underlying assumptions are made in modeling transport distances, such as points of origin and destination. Coal is transported either by land (i.e., rail or truck) or water (i.e., river or Great Lakes). Buffalo was selected as the destination point for Great Lakes transport and New York City was used for land transport. River transport was modeled to stop at the New York–Pennsylvania border north of Pittsburgh to avoid accounting for in-State transportation emissions. Table 19 below shows each state's point of origin for coal transport in 1990, as well as distance to its destination. The same NYS boundaries were used for future years in the time series.

Table 19. Coal Transportation Distances

Destination	Origin Location				
	Pikeville, Kentucky	Cumberland, Maryland	Ohio	Pennsylvania	Charleston, West Virginia
NY/PA border north of Pittsburgh (river)	N/A	N/A	530 mi (from Cincinnati)	130 mi (from Pittsburgh)	410 mi
Buffalo (Great Lakes)	N/A	N/A	N/A	80 mi (from Erie)	N/A
New York City (truck)	640 mi	N/A	460 mi (from Cambridge)	370 mi (from Pittsburgh)	530 mi
New York City (rail)	520 mi	260 mi	N/A	315 mi (from Pittsburgh)	450 mi

Emission factors associated with coal transportation are taken from NETL's Coal Excel model. The model provides emissions data for the transportation modes listed in Table 19 relative to the amount of diesel consumed over a specified distance. The amount of diesel consumed was adjusted by manipulating the underlying distance parameter to those listed in Table 19.

This same approach was used to model coal imports to the four regions from which NYS imports electricity: PJM, ISO New England, Ontario, and Quebec. Since PJM and ISO New England encompass several states, a weighted average of coal delivered to power plants in each state was taken to determine the amount of coal coming from each basin. The amount of coal delivered to power plants and the mode of coal transport were also taken 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. Since the NETL Coal model only profiles U.S. coal basins, associated methane emissions for internationally sourced coal were taken from Appendix B-3 of the EPA's Global Non-CO_2 GHG Emissions Projections (U.S. EPA, 2012) and were divided by total coal produced nationally (IEA, 2023) for the respective year to determine an emission factor. This emission factor was assumed to be representative of underground coal. Surface coal mine methane emissions were modeled as equal to the U.S. national average, as were surface and underground carbon dioxide and nitrous oxide emissions.

Appendix D: Summary Tables of Fossil Fuel Emission Factors provides a breakdown of coal emission factors at each stage of the well-to-combustion fuel cycle.

Table 20 below provides a summary of 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	Used the NETL Coal Extraction and Processing model available in the openLCA software as a source for emission factors for coal (NETL, 2018). This model includes emissions from combustion processes during mining and processing as well as fugitive coal mine CH_4. Infrastructure impacts are excluded.
Source category references	Electricity, industrial, residential, commercial.
Result	Emission factors (CO_2, CH_4, N_2O) for the relevant coal basins and coal types consumed in NYS.
Technological scope	Coal processing accounts for the weighted average mix of cleaned and uncleaned coal. Distribution of coal to powerplants accounts for the distance and mode of transport.
Geographic scope	This model reflects emissions from 10 coal mine basins throughout the United States. FERC Form 423 (FERC, 2011) and EIA Form 923 (EIA, 2023l) provide data on the source of coal by state of origin for utilities back to 1990 for each state. These data are leveraged to identify the appropriate basin and coal type consumed. They are assumed to be the same across all source categories as data for coal consumption by sector are not available prior to 2001. EIA's Annual Coal Distribution Report also provides data on coal transport modes back to 2001 (EIA, 2023g). These data were applied to production values over the entire time series.
Temporal scope	EIA data for coal consumption by sector date back to 2001. 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 emissions from underground coal mine CH_4 by basin, which are used to create 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 does not account for differences across mine basins or mine types.

2.2.18 Petroleum Upstream Fuel Cycle

Upstream petroleum fuel cycle emission factors and data on the domestic and international share of crude oil (Table 21) are sourced from Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) Model 2022 (Argonne National Laboratory, 2022). The modeling uses GREET's default time series data to account for the changing share of conventional oil in the United States. For the entire time series, conventional oil is the largest source of petroleum production, despite the introduction of oil sands in 2000 and shale oil in 2013.

Table 21. Source of Crude at United States Refineries, 2018–2021

Year	2018	2019	2020	2021
U.S. domestic	64.4%	74.4%	80.2%	77.5%
Canada (oil sands)	8.0%	6.5%	7.2%	7.9%
Canada (conventional crude)	9.0%	7.6%	4.9%	5.9%
Mexico	3.1%	2.2%	2.2%	2.1%
Middle East	6.8%	3.2%	2.4%	2.0%
Latin America	5.2%	3.0%	2.0%	1.9%
Africa	2.2%	1.4%	0.5%	1.1%
Others	1.4%	1.2	0.6%	1.5%

Emissions associated with crude extraction and transport in GREET are applied to petroleum products by 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, which reflects the stream of gasoline blendstock prior to mixing with blending components such as ethanol. The ethanol content of gasoline in NYS is based on MOVES. As of 2014, emissions for diesel reflect a 5 percent reduction based on biodiesel content. Emissions for E85 reflect 26 percent of emissions from motor gasoline based on the energy content of gasoline within E85. The source data for each of these assumptions is consistent with the modeling performed for transportation (see section 2.1.5 for on-road motor vehicles).

GREET does not provide data for waxes and lubricants. Research by Sun et al. (2019) to characterize emissions for refinery products at U.S. refineries is used to scale refining emissions for waxes and lubricants from data provided in GREET for residual oil.

Transportation and distribution parameters in GREET are modified to reflect NYS-specific data. Data on annual petroleum imports via tanker and Canadian pipeline are sourced from the EIA's company-level imports archives (EIA, 2023h; EIA, 2023i) while data on domestic, interstate petroleum movement are sourced from EIA's Movement by Pipeline and Refinery and Blender Net Production data sets (EIA, 2023h; EIA, 2023j). Total pipeline quantity to NYS reflects the pipeline capacity of the Colonial, Sun, and Buckeye pipelines (ICF International, 2012). The quantity assumed from the Petroleum Administration for Defense District (PADD) 3 reflects the share of net receipts from PADD 3 by pipeline to PADD 1 (where NYS is located), relative to total production in PADD 1, while the remainder is assumed to be supplied from within PADD 1. Data on barge transport from PADD 3 are from EIA Movements by Tanker and Barge (EIA, 2023i). NYSERDA reports the quantity of receipts by tanker or barge to NYS for 2005 (Rosenberg, Z. and Janney, A., 2006). The share to NYS relative to the rest of PADD 1B is assumed constant throughout the time series.

Table 22 shows a breakdown of petroleum products transported by mode from each region to NYS in 1990. The same method is applied for all other years in the time series.

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

	Pipeline PADD 3[a]	Pipeline PADD 1[b]	Pipeline Canada[c]	Barge PADD 3[d]	Tanker Africa and 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, Texas to New York City.
[b] Assumed transport from Trenton, New Jersey to New York City.
[c] Assumed transport from Fort McMurray, Alberta, Canada to New York City.
[d] Assumed transport from Houston, Texas 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 volume weighted-average distances and total share of the transportation mode are applied in GREET to all petroleum products. Emissions from local distribution of products from bulk terminals via truck transport is accounted for within fuel combustion data in this inventory (see section 2.1.5 for on-road motor vehicles). As a result, transportation parameters for this portion are set to 0 in GREET.

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

- All distribution of petroleum products for Quebec and Ontario is assumed via pipeline.
- Receipts to PJM by barge from PADD 3 reflect the remaining portion of receipts by PADD 1B not allocated to New York State.
- The remaining apparent consumption for PJM not supplied by international imports or barge from PADD 3 is assumed to be supplied via pipeline from PADD 1 or PADD 3.

- Receipts to ISO New England by barge from PADD 3 reflect net movement by barge to PADD 1A (EIA, 2023i).
- The remaining apparent consumption for ISO New England not supplied by international imports or barge from PADD 3 is assumed to be supplied by barge from PADD 1B (ICF International, 2016).

Appendix D: Summary Tables of Fossil Fuel Emission Factors provides a breakdown of gasoline and distillate emission factors at each stage of the well-to-combustion fuel cycle.

Table 23 provides a summary of 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	Used the GREET model to produce emission factors for petroleum products. The GREET model tracks emissions from the extraction of crude oil, transport to refineries, refining into petroleum products, and distribution of petroleum products. GREET also includes the emissions from energy production for energy consumed during these processes. Infrastructure is excluded.
Sector references	Transportation, aviation, commercial, residential, industrial, electricity
Result	Emission factors (CO_2, CH_4, N_2O) by petroleum product from U.S. refineries, specifically conventional diesel, gasoline blendstock, residual oil, and kerosene. The quantity of blended ethanol, biodiesel, or any other bio-based blendstocks is excluded from this accounting and may be accounted for in future iterations of the inventory that include bio-based fuels.
Technological scope	The GREET model uses a weighted average approach on an energy basis to estimate crude oil extraction activities for conventional crude and shale oil. Venting and flaring emissions for crude extraction in GREET are based on the U.S. GHG Inventory, where these emissions are tracked separately for oil and natural gas (Cai, 2018). The model includes average transportation distances and expected transportation mode for imported crudes and distribution of petroleum products within the United States. Emissions from crude oil extraction and transport to refineries are allocated to refinery products at the level of individual refinery processes.
Geographic scope	According to EIA data, refineries in PADD 3 are the largest source of petroleum products to PADD 1 (where NYS is located). PADD 3 is also the largest share of production in the United States (EIA, 2023j; EIA, 2023k). As such, a national, as opposed to PADD-specific, model for extraction and refining of imported petroleum products is sufficient. GREET reflects the mix of foreign and domestic crudes used by U.S. refineries. The default transportation parameters for crude oil in GREET are maintained. Transportation of petroleum products to NYS is modeled according to transportation mode and estimated distance using existing modules in GREET. These data are estimated from reported movement of products between PADDs and imports from foreign countries.

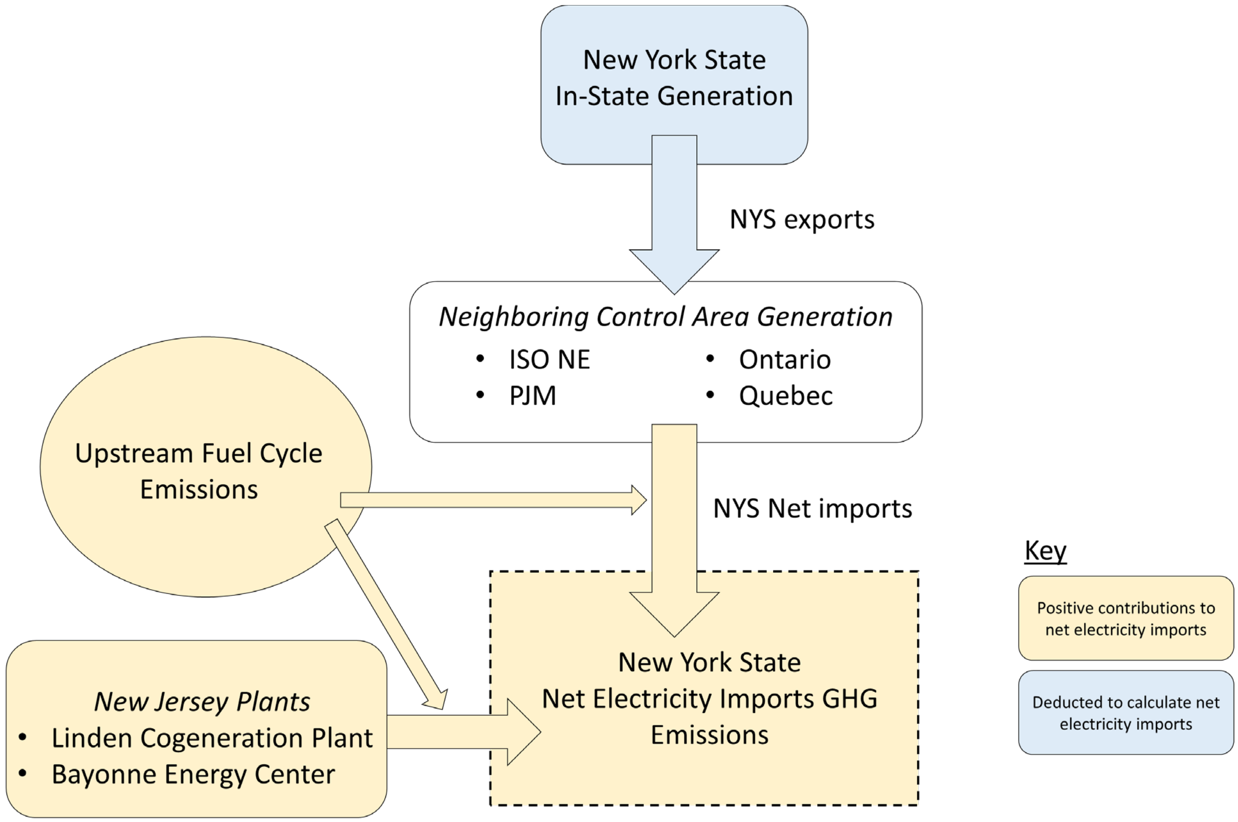
Table 23 continued

Activity	Extraction and Processing of Petroleum Products
Temporal scope	GREET contains time series data—in some cases back to 1990—for understanding emissions over time. Key parameters that are adjusted for the petroleum products supply chain include: • Sources of crude oil • Combustion emission factors (e.g., industrial boilers) • Refinery efficiency • National electricity mix
Alternate approaches considered	Other existing models for extraction (e.g., The Oil Production Greenhouse gas Emissions Estimator (OPGEE)) and refining (e.g., The Petroleum Refinery Life Cycle Inventory Model (PRELIM)) (Brandt, 2018; Bergerson, 2021) require extensive input data that are unavailable for the specific crude assays consumed in NYS. Additionally, these models have been leveraged in developing the GREET model. The EPA Oil and Gas Estimation Tool (U.S. EPA, 2015) utilizes county-level activity data to estimate criteria air pollutant emissions, but these data are too granular for use in the context of imported petroleum fuels where detailed activity location data are not available.

2.3 Energy (Imported Electricity)

To estimate GHG emissions from imported electricity, net electricity imports to NYS from each neighboring region are calculated by subtracting gross electricity exports from gross electricity imports into NYS. An emission factor specific to GHG emissions intensity in each region is applied to estimated net imports from each region. In addition, upstream fuel cycle emissions associated with net electricity imports are estimated by multiplying fuel specific upstream emission factors by net electricity imports (Figure 7). Each of these calculation steps is described in more detail in this section, with consideration for adjustments made across the time series to account for variation in data availability. Specifically, the approach used to estimate emissions for imported electricity is separated into two time periods based on data availability: 1990–2004 and 2005 to present.

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



2.3.1 Net Electricity Imports

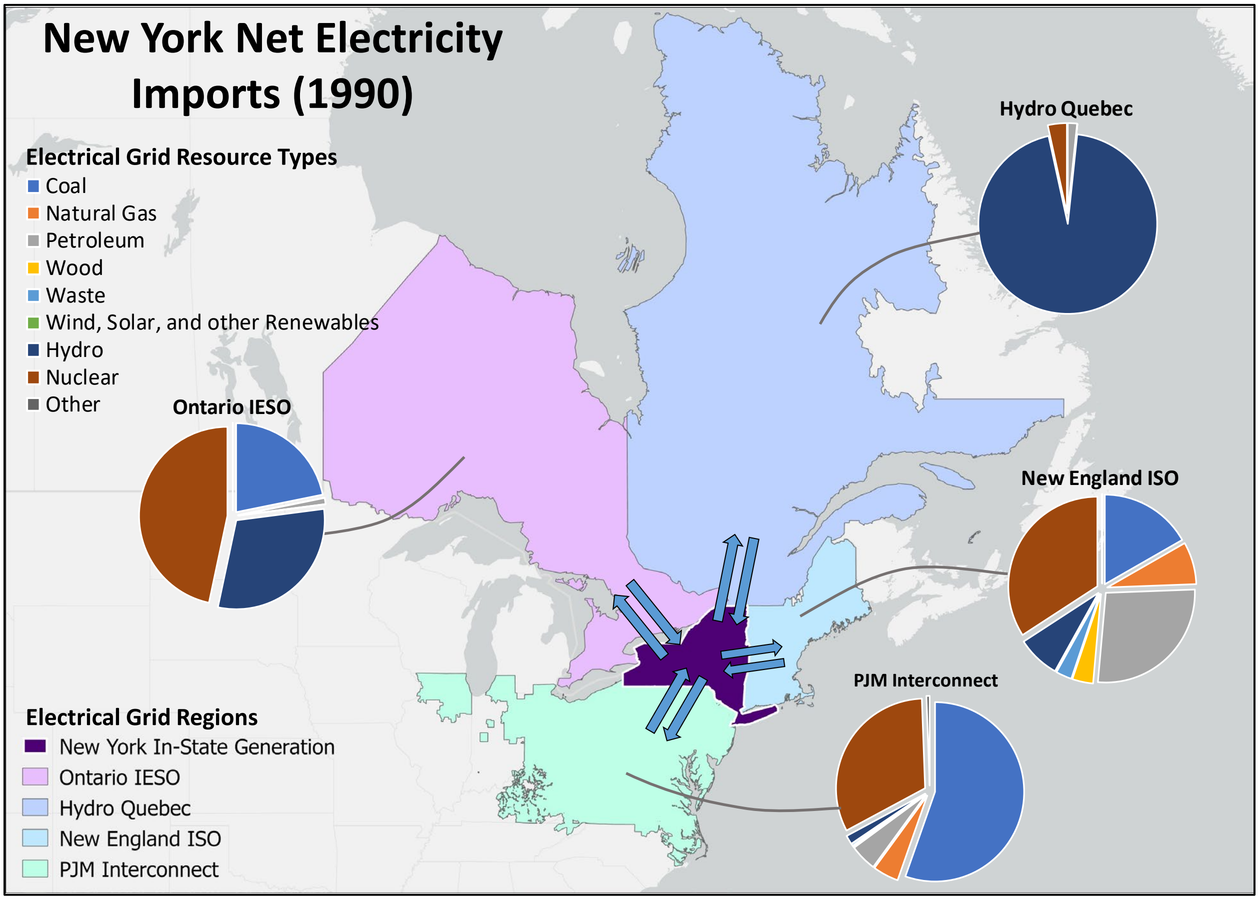
For the time period 1990–2004, data for NYS generation and total system demand are sourced from EIA and New York Independent System Operator (NYISO) Gold Book respectively (NYISO, 2022a). Net imports are calculated by subtracting in-State generation from total system demand. The generation mix for each U.S. based importing region is calculated from fuel specific generation quantities by state from EIA (EIA, 2023l), while the generation mix for Canadian imports is sourced from Canada's National Emissions Inventory (Environment and Climate Change Canada, 2023) (an example for 1990 is shown in Figure 8). No data are available on the share of electricity imported from each region into NYS, so it is assumed that the regional share of electricity in 1990–2004 is proportional to the regional share of electricity imports observed in 2005–2009.

For the time period 2005–present, imported energy is calculated based on reported interface data from NYISO (NYISO, 2022b). Hourly net import data series are tabulated for each of the four surrounding regions: PJM, ISO New England, Quebec, and Ontario. These data have been calibrated with sources like the Regional Greenhouse Gas Initiative report and import data reported by neighboring Independent System Operator (ISOs), and they are broadly consistent with the methodology used in the 2017 Patterns and Trends calculations for this same period.

For years when New York Independent System Operator (NYISO) is a net exporter of energy to a neighboring power control region, the applied emission factor is assumed to be 0 metric tons per megawatt hour. This approach ensures that all emissions produced in NYS continue to be counted in the State.

Two power plants located in New Jersey are electrically connected to the NYISO and supply power directly to NYS. Because of their direct connection, emissions from these plants are associated with the State's electricity demand. These two plants are the 974 MW Linden Cogeneration Plant in Linden, New Jersey, and the 644 MW Bayonne Energy Center in Bayonne, New Jersey. Emissions from these plants are tracked separately for every year using the plant-specific data from U.S. EPA's Air Markets Program data set. This inventory associates these emissions with net electricity imports while identifying them explicitly and transparently, which allows these emissions to be associated with in-State emissions in future inventories if desired. Neither of these two plants was operational for the 1990 baseline inventory year.

Figure 8. New York State Imported Electricity in 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, where possible by fuel type, and multiplied by each region's calculated import quantity to determine total emissions from each region. Emission factors for each region are estimated as follows:

- For the time period 1990–2004, emission factors for PJM and ISO New England are developed by dividing EIA's state-specific CO_2 emissions data by EIA's data on total state generation. For this time period, PJM is defined as the following states: Delaware, Maryland, New Jersey, and Pennsylvania, as well as Washington, D.C. ISO New England includes the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Methane and N_2O emission factors are then estimated by multiplying fuel-specific emission factors from IPCC's AR5 (Myhre et al., 2013) by total fuel consumption in each region, then dividing the total emissions by total state generation. This calculation includes the separate, explicit calculation of biogenic emission factors. In each calculation, generation and emissions associated with the two power plants located in New Jersey but electrically connected to New York State are subtracted.

- For the time period 2005–present, generation and emissions data from the Regional Greenhouse Gas Initiative, EIA, EPA, and the PJM Generation Attribute Tracking System (EIS, 2023) are used to determine appropriate CO_2 emission factors for each import region. For CH_4, N_2O, and biogenic emissions from PJM and ISO New England, data on fuel consumption and generation from EIA are used to derive fuel-specific heat rates, which are then applied to generation data directly from PJM and ISO New England. (Note that this particular step in the methodology begins earlier than 2005 for these two regions depending on when ISO-specific generation data become available. ISO New England data are first available in 2000 and PJM data are first available in 2004.)
- For the New Jersey power plants electrically connected to NYISO, CO_2 emissions are estimated using data from U.S. EPA's Air Markets Program dataset. Using SEDS data (EIA, 2023m) on fuel consumption, the same fuel-specific, IPCC-derived CH_4 and N_2O emission factors discussed above are applied to determine plant-specific non-CO_2 GHG emissions.
- For emission factors associated with Canadian imports, data reported in Canada's National Emissions Inventory (Environment and Climate Change Canada, 2023) for Ontario and Quebec are used. These data are reported for 1990, 2000, 2005, and 2012–present; 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 fuel consumed for generating net electricity imports. The approach used for these emissions is consistent with that described for fuels consumed within NYS. However, adjustments are made to account for specific transportation and distribution modeling for fuels to each neighboring generating region. Relevant details for each fuel are discussed in section 2.2.

3 Results

The following section presents the NYS 1990 to 2021 energy sector GHG inventory results. A full table of results is provided in Appendix F: GHG Inventory Results.

Unless otherwise specified, results shown reflect AR5-20yr GWP, include biogenic carbon dioxide emissions, reflect the High natural gas upstream emission factor calculation approach discussed in section 2.2.1.1, and show hybrid transportation assumptions. Additional sensitivities for these settings are available in Appendix G: Results under Alternative Inventory Settings.

3.1 Time Series Findings

Figure 9 and Table 24 show total energy emissions from 1990 to present broken out by those emissions resulting from in-State sources and emissions from out-of-State sources. In-State emissions includes all in-State fuel combustion as well as all emissions from in-State oil and gas production. Out-of-State emissions includes all net electricity imports and upstream fuel cycle emissions. Total energy sector emissions were 288.4 Mmt CO_2e in 2021. Emissions per capita peaked in 2000 but have since fallen to a low of 13.2 mtCO2e per person in 2020 before rebounding to 14.5 mt CO_2e per person in 2021 (NYS, 2023). In-State emissions of CO_2 contributed 65 percent (186.3 Mmt CO_2e) to total GHGs in 2021.

Figure 9. Total In-State and Out-of-State Energy Emissions, Per Capita Emissions, and 2021 GHG Makeup, Mmt CO_2e for New York State

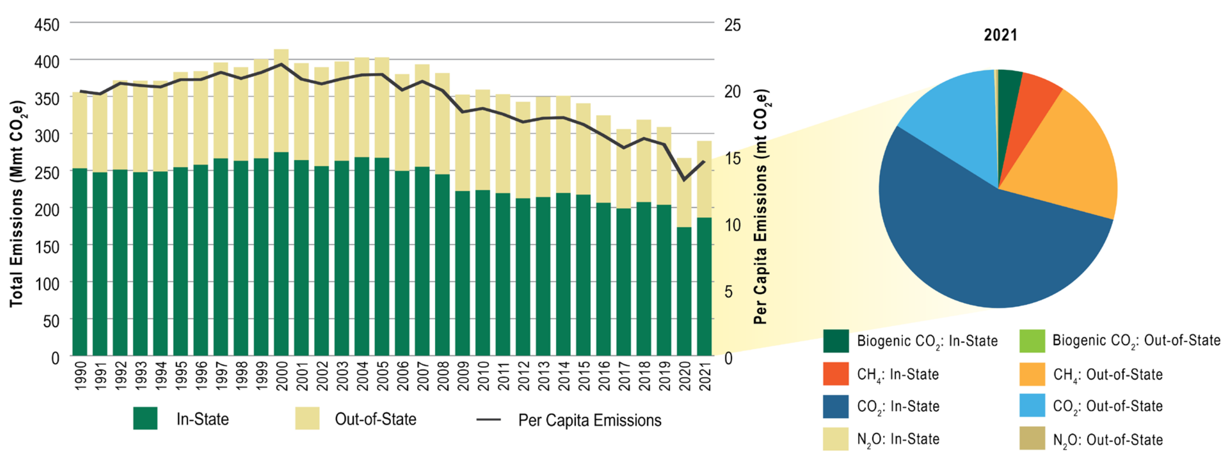


Table 24. Total In-State and Out-of-State Energy Emissions (Mmt CO_2e) for New York State

Emission Category	1990	2000	2005	2010	2015	2019	2020	2021
In-State	252.8	274.7	267.3	223.5	217.4	203.6	173.4	186.3
Out-of-State	102.9	139.0	135.4	135.7	123.4	105.1	92.9	102.1
Total	355.7	413.7	402.7	359.2	340.8	308.7	266.3	288.4

3.1.1 Results by Fuel

Figure 10 and Table 25 show total NYS energy GHG emissions by fuel type from in-State and out-of-State contributions. Emissions from production and use of petroleum products and natural gas products together resulted in 271.5 Mmt CO_2e in 2021. In 2021, in-State petroleum product emissions were the largest contributor to total emissions at 91.5 Mmt CO_2e and was closely followed by in-State natural gas combustion and fugitive emissions at 87.3 Mmt CO_2e. In 2021, out-of-State natural gas production and transmission was the third-largest contributor to total emissions at 60.2 Mmt CO_2e. Out-of-State petroleum product emissions emission totaled 32.5 Mmt CO_2e.

Figure 10. Total In-State and Out-of-State Energy Emissions, by Fuel Group Mmt CO_2e for New York State

- 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

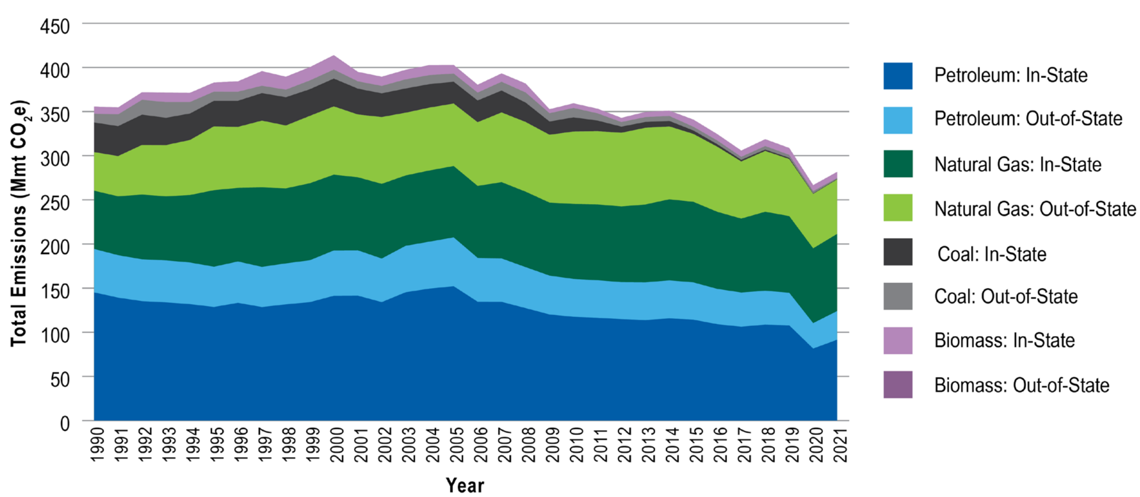


Table 25. Total In-State and Out-of-State Energy Emissions, by Fuel Group, Mmt CO_2e for New York State

Fuel, Context	1990[a]	2000	2005[b]	2010	2015	2019	2020	2021
Petroleum Products, In-State	145.1	141.2	152.1	117.4	114.3	107.8	81.5	91.5
Petroleum Products, Out-of-State	49.2	51.4	55.4	43.0	42.2	37.0	28.9	32.6
Natural Gas Products, In-State	65.9	85.8	80.7	84.9	91.2	86.7	84.6	87.3
Natural Gas Products, Out-of-State	43.7	77.4	70.8	82.0	76.9	64.7	61.3	66.7
Coal Products, In-State	33.6	31.5	24.7	16.1	3.9	1.3	0.6	0.5
Coal Products, Out-of-State	10.0	10.2	9.3	10.7	4.2	3.4	2.7	2.9
Biomass, In-State	8.1	16.2	9.7	5.1	8.1	7.7	6.7	7.0
Biomass, Out-of-State	*	0.1	-	0.1	-	-	-	-
Total	355.6	413.8	402.7	359.3	340.8	308.6	266.3	288.4

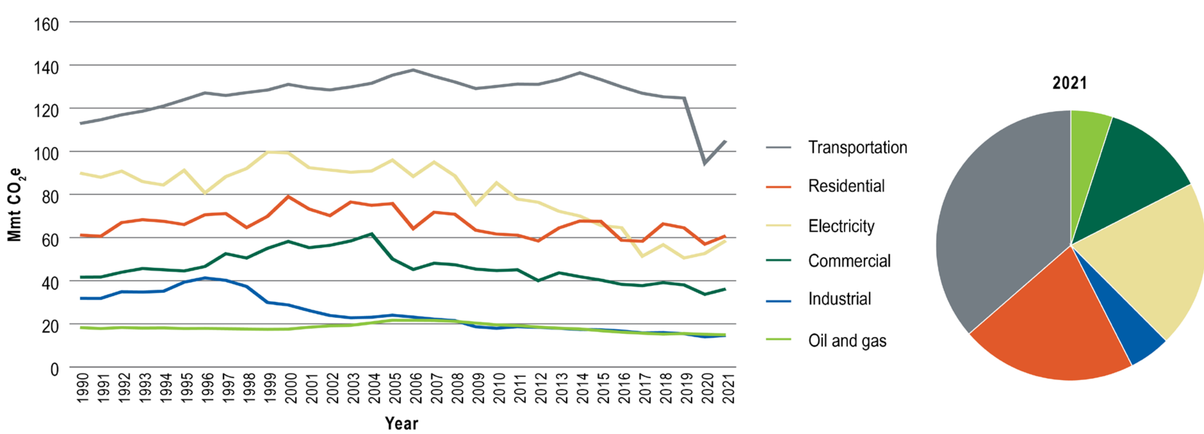
[a] Values marked as "*" indicate negligible emissions that round to 0

[b] "-" indicate no reported emissions.

3.1.2 Results by Sector

Energy emissions by sector are shown in Figure 11. Despite a significant drop due to impacts of the COVID-19 pandemic, combustion and upstream emissions for the transportation sector remain the largest source of energy sector emissions in the State in 2021.

Figure 11. New York State Energy Emissions, by Sector, Mmt CO_2e



3.1.2.1 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 2021 were from in-State (24.5 Mmt CO_2e) and out-of-State (19.1 Mmt CO_2e) natural gas consumption.

Figure 12. New York State Residential Sector Energy Emissions by Fuel, Mmt CO_2e

Other: Coal; Kerosene; LPG

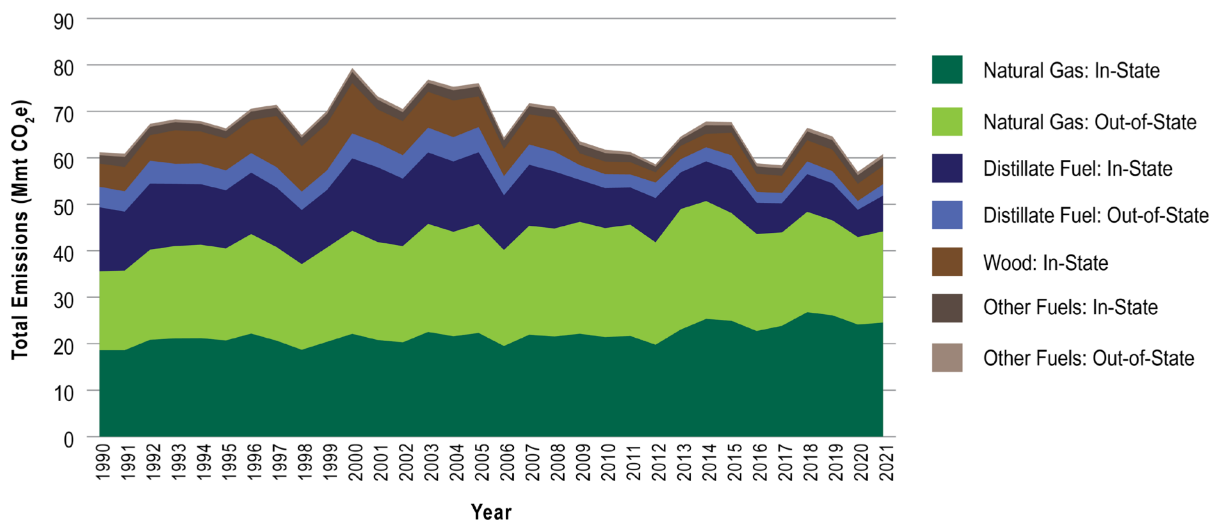


Table 26. New York State Residential Sector Energy Emissions, by Fuel Group and Context (Mmt CO_2e)

Fuel, Context	1990	2000	2005	2010	2015	2019	2020	2021
Distillate Fuel, In-State	13.8	15.5	15.4	8.6	9.2	7.9	5.8	7.7
Distillate Fuel, Out-of-State	4.4	5.1	5.1	2.9	3.1	2.5	1.9	2.5
Natural Gas, In-State	18.6	22.1	22.3	21.4	24.9	26.1	24.1	24.5
Natural Gas, Out-of-State	17.0	22.2	23.4	23.5	23.2	20.4	18.6	19.1
Wood, In-State	5.0	10.8	6.6	2.7	4.8	4.6	3.7	3.9
Other, In-State	1.8	2.4	2.1	1.8	1.6	2.0	1.9	1.8
Other, Out-of-State	0.6	0.9	0.8	0.7	0.7	0.8	0.7	0.7
Total	61.2	79.0	75.7	61.6	67.5	64.3	56.7	60.2

3.1.2.2 Commercial Sector

Figure 13 and Table 27 display commercial sector energy emissions by fuel and in-State/out-of-State categories. Like the residential sector, both in-State (16.4 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 1990–2021.

Figure 13. New York State Commercial Sector Energy Emissions by Fuel, Mmt CO_2e

Other: Coal; Kerosene; LPG; Wood

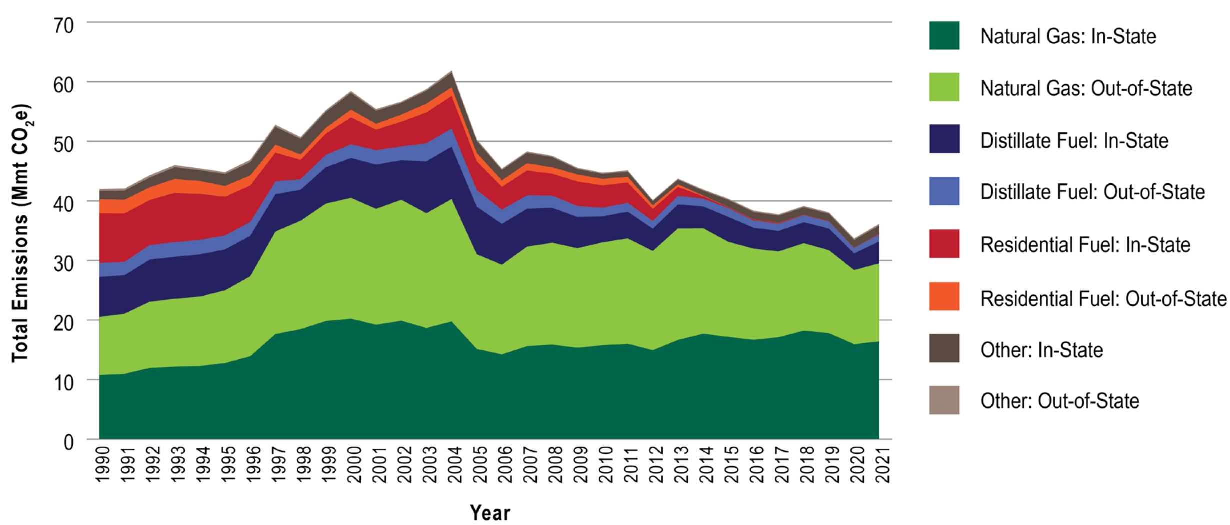


Table 27. New York State Commercial Sector Energy Emissions, by Fuel Group and Context (Mmt CO_2e)

Values marked as "*" indicate negligible emissions that round to 0

Fuel, Context	1990	2000	2005	2010	2015[a]	2019	2020	2021
Distillate Fuel – In-State	6.7	6.7	8.0	4.4	4.2	3.6	2.8	3.7
Distillate Fuel – Out-of-State	2.2	2.2	2.6	1.5	1.4	1.1	0.9	1.2
Natural Gas – In-State	10.7	20.2	15.1	15.8	17.2	17.8	15.9	16.4
Natural Gas – Out-of-State	9.8	20.3	15.9	17.3	16.0	13.9	12.3	12.8
Residual Fuel – In-State	8.3	4.5	4.8	3.8	0.1	0.1	*	0.1
Residual Fuel – Out-of-State	2.2	1.2	1.3	1.0	*	*	*	*
Other – In-State	1.4	2.8	2.0	0.8	1.2	1.2	1.3	1.4
Other – Out-of-State	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3
Total	41.6	58.2	50.1	44.7	40.3	38.0	33.5	35.8

3.1.2.3 Electricity Sector

Figure 14 and Table 28 illustrate trends in electricity sector emissions by fuel type. Figure 14 and Table 28 include electricity imports in the out-of-State fuel emissions categories. Table 28 additionally provides aggregated emissions for all fuels according to in-State combustion, out-of-State upstream, and imported electricity emissions. Between 1990 and 2021, electricity emissions from coal and petroleum declined as natural gas use increased. Where total emissions attributable to natural gas represented 27 percent (24.2 Mmt CO_2e) of those from the electricity sector in 1990, natural gas contributed 93 percent (54.0 Mmt CO_2e) in 2021. Figure 15 shows the electricity generation mix for electricity produced in NYS and illustrates the growth of natural gas use for this sector since the early 2000s (EIA, 2023l). In-State consumption of natural gas for electricity reached an all-time high in 2021, and emissions from natural gas are the highest they have been since 2016, partly due to the closing of the final nuclear reactor of the Indian Point Energy Center in 2021. The reduction in in-state generation in 2021 was primarily offset by an increase in imported electricity from PJM.

Figure 14. New York State Electricity Sector Energy Emissions by Fuel, Mmt CO_2e

Petroleum Products: Distillate Fuel; Petroleum Coke; Residual Fuel

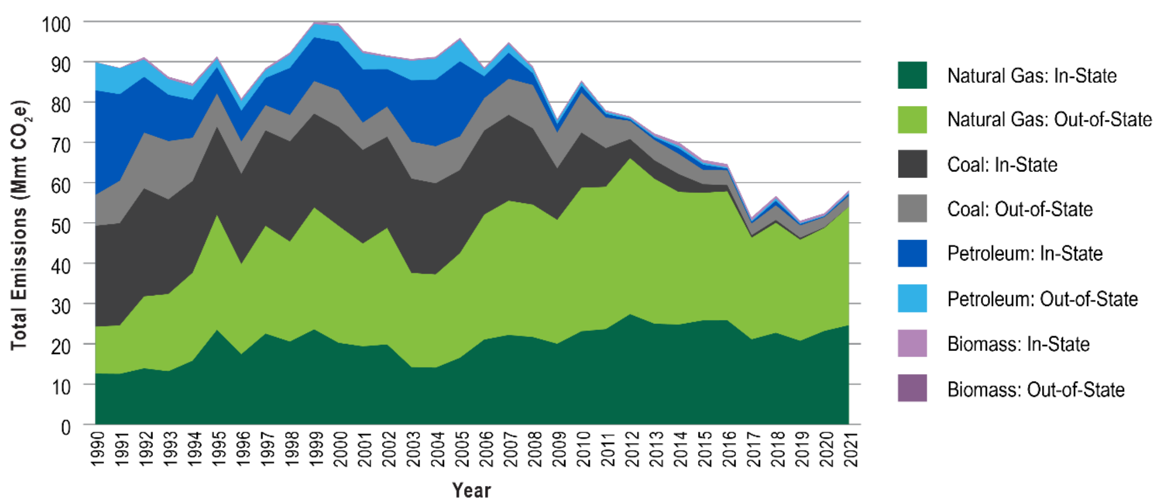


Table 28. New York State Electricity Sector Energy Emissions, by Fuel Group and Context (Mmt CO_2e)

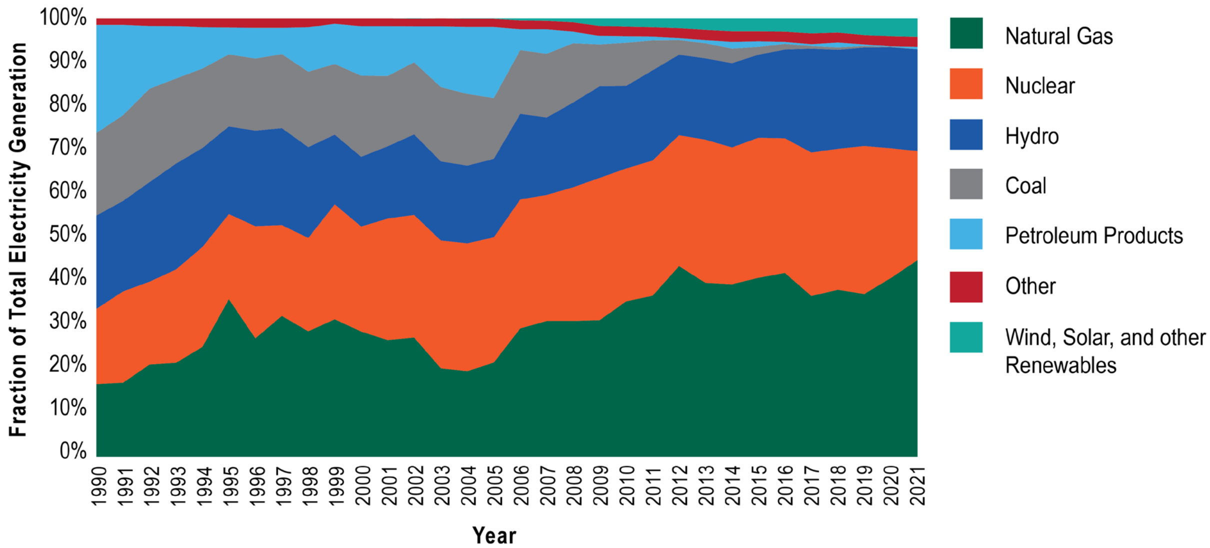
Fuel, Context	1990[a]	2000	2005[b]	2010	2015	2019	2020	2021
Coal, In-state	25.0	24.5	20.6	13.7	2.1	0.5	0.2	-
Coal, Out-of-State	7.7	9.1	8.4	10.0	3.6	3.1	2.5	2.7
Petroleum Products, In-State	25.9	12.0	18.6	1.7	1.3	0.3	0.2	0.5
Petroleum Products, Out-of-State	7.0	3.7	5.3	0.8	0.5	0.2	0.2	0.3
Natural Gas, In-State	12.6	20.2	16.5	23.1	25.8	20.7	23.2	24.6
Natural Gas, Out-of-State	11.6	29.1	26.0	35.6	31.7	25.1	25.6	29.4
Biomass, In-State	0.1	0.6	0.5	0.4	0.7	0.6	0.6	0.6
Biomass, Out-of-State	*	0.1	-	0.1	-	-	-	-
Total	89.9	99.3	95.9	85.3	65.6	50.5	52.4	58.0
Source								
All Fuels, In-State, Combustion	63.6	57.3	56.2	38.9	29.9	22.1	24.1	25.7
All Fuels, Out-of-State Upstream	25.4	32.9	31.8	36.0	29.2	20.6	21.8	24.0
Imported Electricity	0.9	9.0	7.9	10.5	6.6	7.8	6.5	8.4

[a] Values marked as "*" indicate negligible emissions that round to 0

[b] "-" indicate 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*



3.1.2.4 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 and represented 58.2% (8.5 Mmt CO_2e) of total industrial sector emissions in 2021.

Figure 16. New York State Industrial Sector Energy Emissions by Fuel, Mmt CO_2e

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

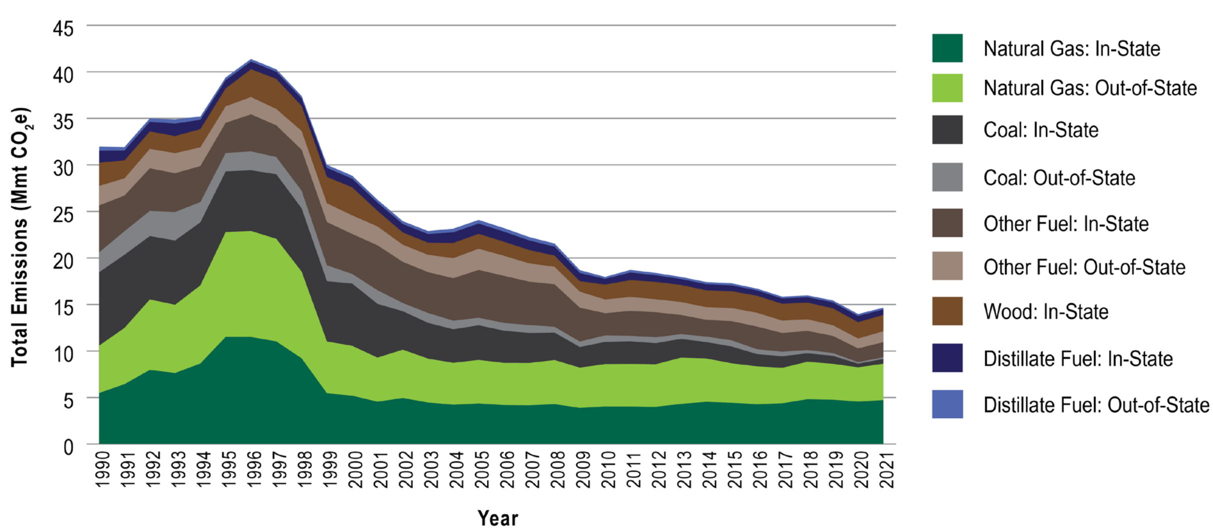


Table 29. New York State Industrial Sector Energy Emissions, by Fuel Group & Context (Mmt CO_2e)

Fuel, Context	1990	2000	2005	2010	2015	2019	2020	2021
Coal, In-State	7.9	6.7	3.7	2.4	1.8	0.9	0.4	0.5
Coal, Out-of-State	2.1	1.0	0.8	0.7	0.7	0.3	0.2	0.2
Distillate Fuel, In-State	1.3	0.9	1.1	0.6	0.6	0.6	0.7	0.6
Distillate Fuel, Out-of-State	0.4	0.3	0.4	0.2	0.2	0.2	0.2	0.2
Natural Gas, In-State	5.5	5.2	4.4	4.0	4.4	4.8	4.5	4.7
Natural Gas, Out-of-State	5.1	5.4	4.7	4.5	4.2	3.9	3.6	3.8
Wood, In-State	2.5	3.0	1.6	1.6	1.8	1.8	1.8	1.8
Other Fuel, In-State	5.0	4.3	5.1	2.4	2.1	1.8	1.5	1.6
Other Fuel, Out-of-State	2.0	1.9	2.2	1.4	1.4	1.1	1.1	1.2
Total	31.8	28.7	24.0	17.8	17.2	15.4	14.0	14.6

3.1.2.5 Transportation Sector

Figure 17 and Table 30 show total transportation sector energy emissions by fuel source for both on-road and non-road vehicles. Gasoline is the largest source of emissions in the transportation sector. In 2021, gasoline consumption contributed 66.8 Mmt CO_2e or 63.7 percent of transportation emissions. Figure 18 shows emissions for on-road transportation only alongside total NYS on-road vehicle miles travelled (VMT) for the 1990–2021 period (U.S. EPA, 2023a). A year after the COVID-19 pandemic, the easing of travel restrictions and stay-in-place orders likely had a notable influence on fuel consumption for the transportation sector and resulted in higher transportation sector emissions in 2021 compared to 2020, though emissions have not yet returned to pre-pandemic levels.

Figure 17. New York State Transportation Sector Emissions by Fuel, Mmt CO_2e

Other: Natural Gas; Residual Fuel; Other

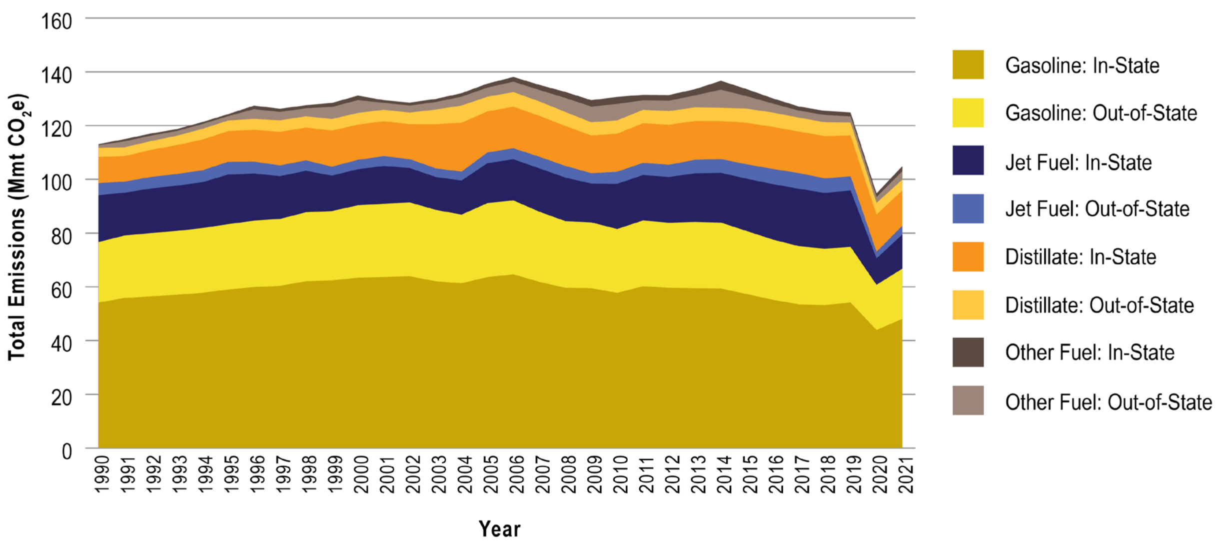
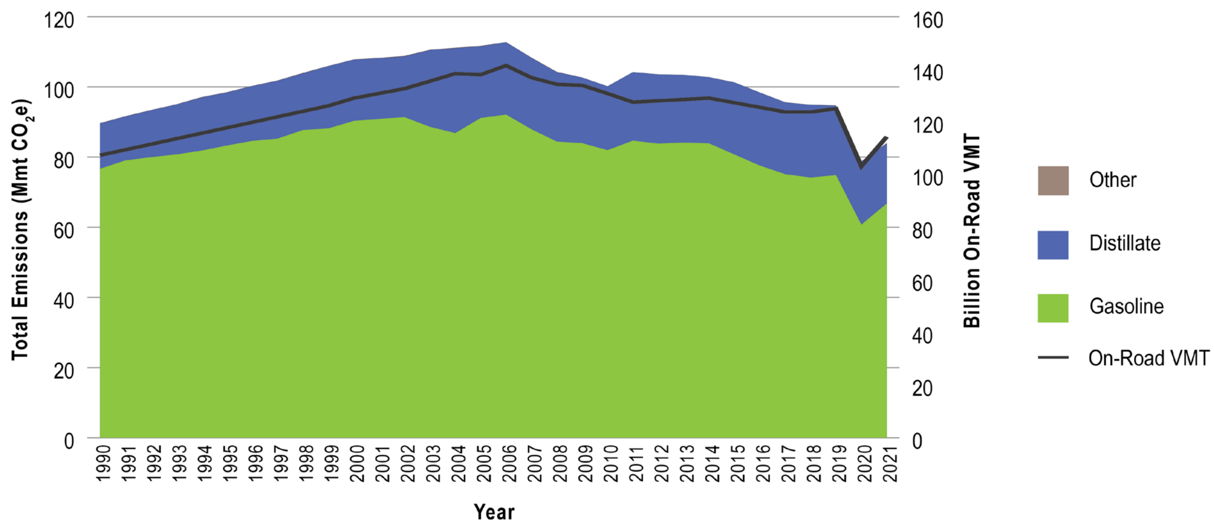


Table 30. New York State Transportation Sector Energy Emissions, by Fuel Group & Context (Mmt CO_2e)

Fuel, Context	1990	2000	2005	2010	2015	2019	2020	2021
Distillate, In-State	9.8	13.1	15.3	13.6	15.4	15.2	13.8	13.1
Distillate, Out-of-State	3.2	4.4	5.2	4.6	5.1	4.6	4.2	4.0
Gasoline, In-State	54.1	63.4	63.6	58.2	57.3	54.1	43.9	48.1
Gasoline, Out-of-State	22.5	27.0	27.5	23.8	23.5	20.7	16.8	18.7
Jet Fuel, In-State	17.4	13.4	14.8	16.8	19.5	21.0	9.8	12.7
Jet Fuel, Out-of-State	4.5	3.5	4.0	4.5	5.4	5.3	2.5	3.3
Other, In-State	0.9	4.8	3.4	6.1	4.6	2.3	2.2	3.1
Other, Out-of-State	0.4	1.6	1.5	2.5	2.6	1.5	1.3	1.8
Total	112.8	131.2	135.3	130.1	133.4	124.7	94.5	104.8

Figure 18. NYS On-Road Transportation Sector Emissions, by Fuel Category, Mmt CO_2e, and Billion On-Road VMT, 1990–2021

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



3.1.2.6 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 2021, upstream oil and gas emissions contributed 2.9 Mmt CO_2e; mid-stream oil and gas emissions contributed 6.2 Mmt CO_2e; and downstream oil and gas contributed 5.9 Mmt CO_2e. See the New York State Oil and Gas Methane Emissions Inventory: 1990–2021 report for more details regarding the calculation of NYS oil and gas supply chain emissions (NYSERDA, 2023).

Figure 19. New York State Emissions from In-State Oil and Gas Systems, Mmt CO_2e, by Stage

- Upstream: Drill rigs; Drilling Fugitives; Oil/Gas Well: Mud Degassing; Oil/Gas Well Completions; Oil/Gas Conventional Production; Oil/Gas Abandoned Wells.
- Mid-Stream: 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.

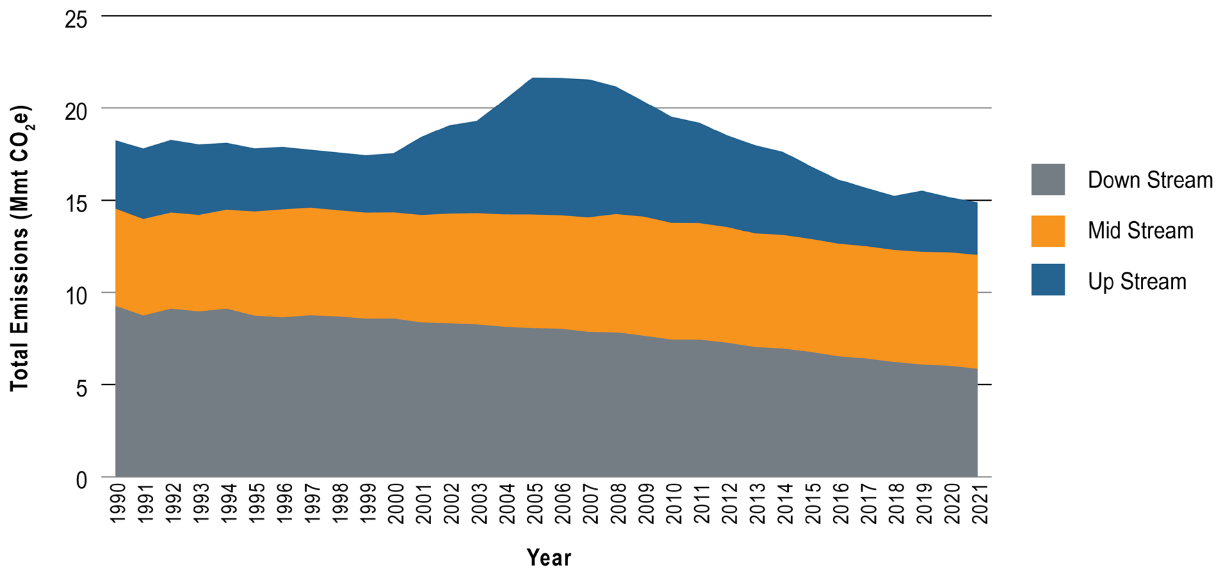


Table 31. New York State Oil and Gas Sector Energy Emissions, by Context (Mmt CO_2e)

Context	1990	2000	2005	2010	2015	2019	2020	2021
Upstream	3.7	3.2	7.4	5.8	3.9	3.3	3.0	2.9
Mid-Stream	5.3	5.8	6.2	6.3	6.1	6.1	6.2	6.2
Downstream	9.3	8.6	8.1	7.4	6.8	6.1	6.0	5.9
Total	18.3	17.6	21.7	19.5	16.8	15.5	15.2	15.0

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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, as well as the U.S. GHG Inventory and the California GHG Inventory. ERG then constructed a side-by-side comparison of the various methods and inventory characteristics. Table A-1 provides a summary of these findings.

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 US 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 non-energy consumption activity based on industrial fuel non-energy 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 New York State 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 be used to develop MOVES parameters; if necessary, default information will be used to supplement NYS-specific data. ERG will obtain NYS's most recent MOVES inputs developed by NYSDEC for the 2017 NEI and the 2016 modeling platform (years 2016, 2023, and 2028). ERG will adapt the year 2017 county databases so that MOVES can use the data in other calendar years starting from 1990 to the desired future year. The database modifications will be the same as those ERG uses to support U.S. EPA's modeling activities in which historic and future years rely on similar databases year to year. The exception to this will be for commonly adjusted location-specific parameters (i.e., NYS-specific fuel properties, inspection/maintenance programs, and activity). Another key input is a NYS-specific trend of vehicle population and VMT growth year over year by vehicle class. Age distribution will also be an important input in the trend analysis, since that input is partly responsible for allocating activity into vehicle model years, which are subject to different fuel economy standards. Where it is not possible to acquire new input data, we will rely on U.S. EPA methods in use for current modeling efforts or MOVES model national data if needed. Using MOVES to estimate emissions reduces uncertainty because it accounts for where emissions occur rather than where on-road fuels are purchased—it is believed that this discrepancy may be particularly relevant to the New York City metropolitan area (i.e., fuels may be bought 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 upon appropriate data series as detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA, 2023m). In addition, use estimates of passenger, freight, and mail miles from Bureau of Transportation Statistics to resolve/adjust potential aviation fuel discrepancies at large NYS airports. Follow IPCC Guidelines regarding boundaries associated with 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 appropriate data series as detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA, 2023m). Follow IPCC Guidelines regarding boundaries associated with 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 upon appropriate data series as detailed in "Consumption Technical Notes" appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA, 2023m). Follow IPCC Guidelines regarding boundaries associated with 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 upon appropriate data series as detailed in “Consumption Technical Notes” appendix in *State Energy Consumption Estimates 1960 Through 2017* (EIA, 2023m). Since nonroad fuel use occurs across many sectors, clearly identify where all nonroad fuel use occurs. 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 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 production sector; use national data for other sectors. Use the pollutant ratios developed with national-level data from the U.S. GHG Inventory to estimate CO_2 and N_2O emissions for oil systems. Additionally, EIA data indicate that there was a single refinery that 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 (National Academies of Sciences, Engineering, and Medicine, 2018).

Appendix B. Fuel Carbon Contents and Combustion Emission Factors

Table B-1 provides the carbon contents used for selected fuel types in the NYS energy sector GHG inventory for 2021. Table B-2 lists the CH_4 and N_2O combustion emission factors for the selected fuels in the NYS energy sector GHG inventory for 2019. Units shown are based on the units utilized in the original data source for the carbon contents and emission factors.

Table B-1. Carbon Content of Selected Fuels in 2021 (Metric Tons per 10^9 Btu)

Source: (U.S. EPA, 2023c)

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	26.16
Residential	Distillate fuel	20.22
Residential	Kerosene	19.96
Residential	LPG	17.15
Residential	Natural gas	14.43
Residential	Wood	28.13
Commercial	Coal	26.16
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	25.6
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
Industrial	Natural gas	14.43
Industrial	Petroleum coke	27.85

Table B-1 continued

Sector	Fuel	Carbon Content
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	19.70
Transportation	Residual fuel	20.48
Transportation	Natural gas	14.43

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

Sources: (U.S. EPA, 2023c); (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
Industrial	Kerosene	3	0.6	g/GJ
Industrial	LPG	1	0.1	g/GJ

Table B-2 continued

Sector	Fuel	CH_4	N_2O	Units
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	2.008	0.054	g/kg fuel
Transportation—Military	Residual fuel oil	0.309	0.088	g/kg fuel
Transportation—Bunker Vessel	Distillate fuel	2.008	0.054	g/kg fuel
Transportation—Bunker Vessel	Residual fuel oil	0.309	0.09	g/kg fuel
Transportation—Other Nonroad	Distillate fuel	0.317	0.295	g/kg fuel
Transportation—Other Nonroad	Industrial/commercial equipment: gasoline—4 stroke	0.980	0.550	g/kg fuel
Transportation—Other Nonroad	Construction/mining equipment: equipment gasoline—4 stroke	1.022	0.528	g/kg fuel
Transportation—Other Nonroad	Airport equipment gasoline—4 stroke	0.370	0.383	g/kg fuel
Transportation—Other Nonroad	Lawn and garden equipment: residential gasoline—4 stroke	1.080	0.696	g/kg fuel
Transportation—Other Nonroad	Ships and boats: gasoline—4 stroke	0.808	0.003	g/kg fuel
Transportation—Other Nonroad	Recreational equipment: gasoline—4 stroke	0.980	0.531	g/kg fuel

[a] Emission factors used for fuel consumption method only. MOVES calculates CH_4 and N_2O emissions internal to the mode.

Appendix C. MOVES Model Settings

C.1 MOVES Run Settings and NYS Input Data

MOVES was run for calendar years 1990 and 1999–2021 using the “Default Scale” feature of the model, which is a level of detail at which MOVES can estimate emissions at different geographic resolutions (i.e., nation, state, or county) using entirely pre-populated data. Alternatively, local information for any data table may be provided to MOVES. Model runs for the NYS GHG Inventory used the MOVES Default Scale to estimate the statewide GHG emissions with updates to VMT and vehicle population to better characterize the NYS vehicle fleet mix. MOVES was not designed to run calendar years 1991–1998, so the NYS GHG Inventory was interpolated between 1990–1999 for these eight years.

Other MOVES data were left as default values (e.g., age distribution, vehicle speed distributions, fuel formulations, distribution of fuel types, temperature and relative humidity, vehicle inspection and maintenance programs). To model the 1990 and 1999–2021 calendar years, three custom database tables were created for MOVES:

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

Table C-1 shows the list of input parameters in MOVES with the setting selected for NYS.

Table C-1. MOVES Input Parameters and Run Settings Selected for NYS

MOVES Input Parameter	MOVES Run Setting/Selection
Model	On-road
Domain/Scale	Default
Calculation Type	Inventory
Time Aggregation Level	Year
Years	1990, 1999–2021
Months	12 months
Days	Weekday, weekend day
Hours	24 hours

Table C-1 continued

MOVES Input Parameter	MOVES Run Setting/Selection
States	New York
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 Data Sets	Custom input database for New York State containing tables for: “HPMSVtypeYear” containing the annual 1990 and 1999–2021 VMT for NYS. “SourceTypeYear” containing the 1990 and 1999–2021 population for NYS. “ZoneRoadType” containing the normalized county allocation factors needed to allocate New York statewide VMT and population to NYS counties.
Output Database (assigned name)	nyserda_1990to2021_out
Output Units	Mass: U.S. ton (later converted to metric tons) Energy: Kilojoules Distance: Miles
Output Activity Types	All types selected: distance traveled, source hours, hoteling hours, source hours operating, source hours parked, population, starts.
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 Data Sets, Selections: ‘nyserda_1990to2021_in’

The VMT used in MOVES for NYS are shown in Table C-2 for select years in the time series.

Table C-2. MOVES VMT Input for NYS (Million Miles)

HPMS Vehicle Type	1990	2000	2010	2015	2019	2020	2021
10: Motorcycles	107	415	718	738	499	498	394
25: Light Duty Vehicles	103,000	117,000	122,000	117,000	114,710	93,657	98,810
40: Buses	540	897	644	974	1,014	559	692
50: Single Unit Trucks	1,974	4,664	3,610	4,506	3,979	3,785	3,434
60: Combination Trucks	1,748	6,073	3,854	3,775	3,784	3,978	3,542

The vehicle population used in MOVES for NYS are shown in Table C-3 for select years in the time series.

Table C-3. NYS Vehicle Population

MOVES Source Type	1990	2000	2010	2015	2019	2020	2021
11: Motorcycle	40,167	148,222	310,646	323,910	213,279	212,425	167,908
21: Passenger Car	7,655,857	6,359,743	6,029,479	4,750,572	4,378,566	3,568,488	3,765,899
31: Passenger Truck	1,461,415	3,328,421	4,105,148	4,900,300	4,865,583	3,953,234	4,163,125
32: Light Commercial Truck	522,476	389,729	480,680	573,784	569,720	462,892	487,468
41: Intercity Bus	3,166	13,780	11,426	14,791	15,272	8,359	10,311
42: Transit Bus	3,099	4,045	4,165	6,220	6,142	3,370	4,165
43: School Bus	26,830	26,718	22,071	29,099	26,782	14,697	18,163
51: Refuse Truck	1,858	4,534	2,318	2,146	1,937	1,841	1,668
52: Single Unit Short-Haul Truck	107,824	243,334	227,333	302,206	272,796	259,294	234,828
53: Single Unit Long-Haul Truck	4,052	10,732	10,026	13,329	12,031	11,436	10,357
54: Motor Home	25,835	46,680	28,204	29,981	27,063	25,724	23,296
61: Combination Short-Haul Truck	18,945	50,942	24,006	22,903	21,484	22,304	19,690
62: Combination Long-Haul Truck	11,336	39,830	31,963	38,008	35,654	37,015	32,676

C.2 VMT Inputs to MOVES

The annual VMT provided to MOVES for years 1990 and 1999–2016 equals the values from the previous NYS GHG Inventory (NYSERDA, 2019a), which also matches the VMT reported for NYS in the Federal Highway Administration's (FHWA) Highway Statistics Table VM-2.

To complete the time series, the NYS VMT were extracted from the FHWA VM-2 tables for 2017 through 2021. The VM-2 table provides only total VMT by functional class (roadway type) and does not delineate the activity by vehicle class. Instead, the FHWA Highway Statistics Table VM-4 contains state-specific distributions of VMT by HPMS vehicle classes, and VM-4 is available for many years (though not all) in the time series; the VM-4 tables exist for years 1994–1999, 2009–2010, 2013–2015, and 2017–2021. For most years without VM-4 coverage, the vehicle type mix was interpolated between the closest two years with VM-4 data.

Because a VM-4 table is not available for the base year 1990, a different approach was applied. For 1990, VMT were estimated by HPMS vehicle type based on re-mapping the 1990 VMT from the prior SIT. The vehicle type mapping was accomplished in two steps. The first step is shown in Table C-4 below. Motorcycle VMT were not modified; light-duty vehicles were aggregated into the HPMS vehicle type group "25" (all Light-Duty Vehicles); and the heavy-duty vehicles were aggregated into a group of HPMS vehicle types including "40" (Buses), "50" (Single-Unit Trucks), and "60" (Combination Trucks) together.

Table C-4. Step 1: Aggregation from SIT to Groups of MOVES HPMS 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	84,372	25	102,532
Light-Duty Gasoline Truck	17,552		
Light-Duty Diesel Vehicle	26		
Light-Duty Diesel Truck	582		
Heavy-Duty Gasoline Truck	206	40, 50, 60	4,262
Heavy-Duty Diesel Truck	4,056		
Total	***106,901***		***106,901***

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

Table C-5. Step 2: Disaggregation into All Five MOVES HPMS 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 above NYS-specific mapping fractions for buses, single-unit trucks, and combination trucks are different from the national average default in MOVES. The MOVES2014b default relative fractions are 0.054 (buses), 0.373 (single-unit trucks), and 0.572 (combination trucks). Compared to the national average, NYS has a higher portion of bus and single-unit truck VMT, and lower combination truck VMT. Table C-6 is a reference table showing how HPMS vehicle types align with MOVES source use types. At the start of a model run, MOVES apportions 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. MOVES HPMS 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 previously mentioned, the NYS-specific VMT mix by HPMS vehicle class (VM-4 table) was directly available for the years 1999, 2009–2010, 2013–2015, and 2017–2021. Therefore, the VM-4 VMT were directly allocated into the five HPMS types for these years. The VMT mix by HPMS vehicle type for years 2000–2008, 2011–2012, and 2016 was interpolated from the closest two years, 1990, and/or year(s) with a VM-4 table. During a MOVES run, the model apportions the incoming VMT by HPMS vehicle types into source types, model years, and fuel types using underlying data in the model database.

C.3 Population Inputs to MOVES

Due to the unavailability of 1990–2021 vehicle population data for NYS, the MOVES based estimate relied on MOVES model assumptions (U.S. EPA, 2023a) of mileage accrued per year, per vehicle. Vehicle population inputs are categorized by MOVES source types, and the input table was prepared by dividing the annual source type VMT by the MOVES default ratio of VMT to population. 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. The VMT per vehicle, per year tend to increase over time in MOVES, and year-specific ratios were multiplied by the corresponding year’s VMT to prepare 1990 and 1999–2021 vehicle populations.

Table C-7. VMT-to-Population Ratios: Year 1990

Source Type ID	Source Type Description	MOVES Default Ratio (Miles/Vehicle/Year)
11	Motorcycle	3,118
21	Passenger Car	10,418
31	Passenger Truck	11,594
32	Light Commercial Truck	11,735
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 at the state level for NYS. The model subsequently allocated this activity to the 62 counties in the State using a modified version of the “ZoneRoadType” table. The MOVES data source behind the county allocation factors in the “ZoneRoadType” table is based on year 2011 HPMS state-level data collected annually by the FHWA that U.S. EPA processed for NEI (U.S. EPA, 2023b). The allocation of VMT activity to counties is relevant to the statewide inventory because different counties are tied to different ethanol blends by calendar year.

MOVES determines the age and fuel type of the incoming VMT and population data using a variety of underling model tables. First, MOVES disaggregates VMT from HPMS vehicle types into source types and model years using the age distribution by source type (the “SourceTypeAgeDistribution” table) and relative annual mileage accumulation rates (the “SourceTypeAge” table). The MOVES national age distributions are derived from historical vehicle registration data for two years: 1990 and 2014. The age distributions for other years are projected based on an algorithm that accounts for growth and vehicle scrappage as vehicles age. The U.S. EPA did not obtain the registration data for every calendar year for MOVES because it is prohibitively costly, hence the need for algorithms to estimate other years. MOVES also uses age distributions directly (not relative mileage accrual rates) to distribute vehicle population into vehicle model years, or age.

For VMT apportionment into vehicle ages, MOVES uses relative mileage accumulation in addition to age distribution to account for fact that older vehicles typically travel fewer miles annually than newer vehicles. The data source used by MOVES for relative annual mileage accumulation rates is primarily the 2002 Bureau of Transportation Statistics Vehicle Inventory and Use Survey (VIUS) (U.S. Census, 2004) and a 2001 National Highway Traffic Safety Administration (NHTSA) survey (U.S. EPA, 2020b). After MOVES apportions VMT and population into source type and model year, the model applies fractions to estimate the portion of gasoline, diesel, CNG, and E85-capable (or "flex fuel") vehicles that make up each model year. Flex-fuel vehicles may operate on high-ethanol fuels such as E85 or conventional gasoline, depending on local fuel availability. The model table responsible for apportioning model year, VMT, and population into fuel type is the "SampleVehiclePopulation" table, and its data sources are the 2014 vehicle registration data and 2002 VIUS classifications. It is possible to override this information in MOVES, through the "AVFT" (Alternative Fuel Vehicle and Technology) table. The `AVFT` table lists source type, model year, fuel type, and the fraction of vehicle population, where the fractions sum to one (1) for each source type and model year.

C.5 Alternative Fuels and Biogenic Fuel Supply

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

The current version of MOVES3, used for this inventory estimates CNG for only the heavy-duty source types, and the CNG amount grows steadily over the years 1990–2021. Similarly, MOVES estimates flex-fuel vehicles for only three source types: passenger cars, passenger trucks, and light commercial trucks. The fuel type fraction MOVES assigns to flex-fuel vehicles is 0 through model year 1997, 1% to 2% in 1998, and increasing percentages into later model years (e.g., 5% for cars and 19% for light trucks). The flex-fuel vehicles may operate on either gasoline or E85. Another MOVES table, "FuelUsageFraction," assumes less than 2% of the flex-fuel vehicles will use high-ethanol E85 fuel in calendar years 2010 and later. In the MOVES "FuelSupply" and "FuelFormulation" tables, MOVES assumes conventional diesel (B0) is in use through calendar year 2010, switching entirely to B5 (5% biodiesel) starting in 2011.

C.6 Separate Tracking of Ethanol Fuels

A requirement of this study was to separate the CO_2 emissions from the fossil-fuel portion of fuels from the biogenic portion. Biogenic fuels refer to the ethanol mixed with conventional gasoline to make E10 and E85, and the volume of biodiesel ester mixed with conventional diesel to make B5. MOVES fuel type identification codes and fuel supply assumptions allow for a straightforward accounting of E85 (separate from gasoline) and B5 (separate from conventional diesel). Unfortunately, MOVES does not output E10 and E15 fuel types separately from each other or from E0. Instead, MOVES labels them all as fuel type ID = 1. A separate set of MOVES runs was performed over 1999–2021 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 results separately for E0 versus E10 over 1999–2011. The 2012 and later fuel supply in MOVES for NYS was entirely E10, and the 1990 fuel supply was entirely E0. With the separate accounting for E0, E10, E85, B0, and B5 fuels, the biogenic fuels portion of the CO_2 was calculated as follows:

- 10% of the E10-fueled CO_2
- 74% of the E85-fueled CO_2
- 5% of the B5-fueled CO_2

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

An example calculation demonstrating the calculation performed by MOVES for CO_2 is:

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

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 (grams/kilojoule of energy)

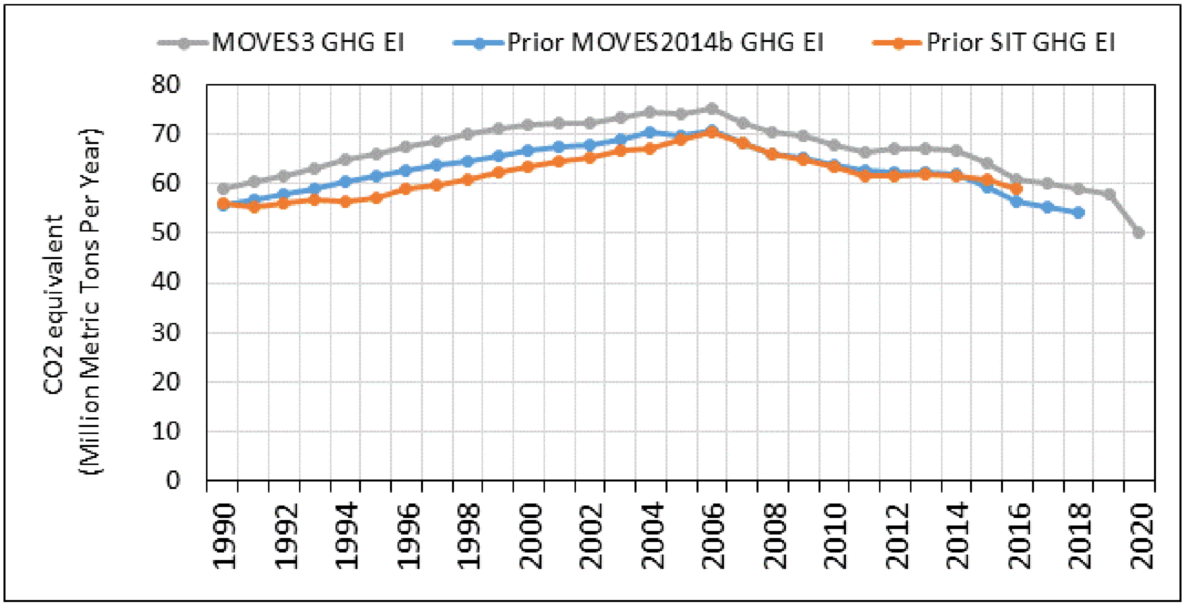
OF = Fraction of carbon that is oxidized to form CO_2 in the atmosphere; MOVES assumes an oxidation fraction of 1 for hydrocarbon-based fuels

44 = Molecular mass of CO_2

12 = Atomic mass of carbon

Figure C-1 and Table C-8 show the comparison of CO_2e emissions estimated using the MOVES model and the prior SIT-based approach. The prior SIT results came from the spreadsheet titled *Mobile Combustion-pm07.xlsm* (two tabs: *Summary* and *CO2 Summary*) and the numbers reproduced below represent the Mobile Sources total minus the Non-Highway subtotal CO_2e. Because the prior SIT combined CH_4 and N_2O into CO_2e using AR4 100-year GWP values, the newly estimated MOVES-based emission estimates were also converted to CO_2e using AR4 100-year GWP values for benchmark comparison purposes. The relatively larger percent differences over 1991–2004 for the prior MOVES2014b and the prior SIT results are thought to be due to an assumption of lower heavy-duty vehicle VMT contribution in the prior SIT. MOVES3 estimates higher carbon dioxide emissions than MOVES2014b by approximately 6 to 8% in near term years (U.S. 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 are a small part of the CO_2e presented in Figure C-1.

Figure C-1. Comparison of Transportation Model CO_2e Emissions Trends by Year



The large changes in methane from MOVES3 can be observed by comparing the Excel workbook deliverable time series for the transportation sector to the prior inventory completed with MOVES2014b. In the MOVES3-based GHG time series, methane emissions from gasoline-fueled vehicles are approximately four times higher than the prior inventory in years 1990–2010, and methane from diesel-fueled vehicles are zero for years 1990 through 2006. These changes are expected due to the model change. MOVES3 contains updated organic gas speciation profiles, including methane emissions, which caused the NYS gasoline-fueled methane emissions to increase significantly (U.S. EPA, 2021). EPA analyzed new data for MOVES3 and found that diesel-fueled methane emissions were negligible for the vehicle model years (MDYs) 2006 and earlier (U.S. EPA, 2023e). Therefore, the Excel workbook deliverable time series also shows zeros for the calendar years 1990–2006. In calendar year 2007 and later, there are increasing amounts of 2007 and later MDYs in the fleet which have non-zero methane emissions. Although the methane changes are large, the overall impact on CO_2e is small.

Table C-8. Comparison of MOVES3-Based GHG Emissions Inventory with the Prior SIT GHG Emissions Inventory by Year

Year	MOVES3-Based GHG Emissions Inventory[a] (MT CO_2e)	Prior SIT GHG Emissions Inventory (MT CO_2e)	Percent Difference (MOVES3-SIT)/SIT
1990	59,101,585	55,929,851	5.7%
1991	60,311,316	55,487,679	8.7%
1992	61,521,047	55,995,700	9.9%
1993	63,135,054	56,658,136	11.4%
1994	64,796,021	56,561,210	14.6%
1995	66,077,215	57,258,118	15.4%
1996	67,358,409	58,873,038	14.4%
1997	68,639,603	59,695,083	15.0%
1998	69,920,797	61,012,490	14.6%
1999	71,201,991	62,181,873	14.5%
2000	71,815,932	63,379,215	13.3%
2001	72,201,504	64,362,308	12.2%
2002	72,420,719	65,223,338	11.0%
2003	73,376,903	66,702,505	10.0%
2004	74,642,927	67,028,478	11.4%
2005	74,115,724	68,791,539	7.7%
2006	75,133,086	70,409,700	6.7%
2007	72,364,488	68,382,003	5.8%
2008	70,399,621	66,095,772	6.5%
2009	69,531,974	65,020,231	6.9%
2010	67,787,588	63,380,244	7.0%
2011	66,274,061	61,504,645	7.8%
2012	67,205,599	61,565,912	9.2%
2013	67,190,631	62,108,961	8.2%
2014	66,580,884	61,758,601	7.8%
2015	64,238,968	60,729,501	5.8%
2016	60,935,098	59,112,860	3.1%
2017	60,085,334		
2018	58,835,072		
2019	57,890,358		
2020	50,173,394		

[a] CH_4 and N_2O are converted to AR4 100-year basis for consistency with 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 NYS in 2021. Stages include out-of-State (further broken down into sub-stages specified in Table D-1), in-State, and combustion. Coal and natural gas emission factors are representative of electricity end-use while distillate fuel and gasoline emission factors are representative of use in on-road motor vehicles. (Note that the emission factors for distillate fuel and gasoline exclude the biogenic portion of the blended feedstock).

Table D-1. Out-of-State Sub-stages 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 values are in lb CO_2e/mmBtu, and Table D-3 values are in raw lb of pollutant/mmBtu. Both tables present 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. 2021 Well-to-Combustion Fossil Fuel Emission Factors (lb CO_2e[a]/mmBtu)

Stage	Out-of-State Stage #	Pollutant	Coal	Distillate	Gasoline	Low	Mid	High
						Natural Gas		
Out-of-State	1	CO_2	5.91	13.03	11.26	6.30	6.30	6.27
		CH_4	64.55	18.35	15.85	15.88	30.88	39.60
		N_2O	0.06	0.06	0.05	3.90E-3	3.90E-3	3.88E-3
Out-of-State	2	CO_2	1.36	18.06	30.42	7.26	7.26	7.26
		CH_4	0.003	3.79	7.68	9.28	9.28	10.38
		N_2O	0.003	0.10	0.14	1.71E-5	1.71E-5	1.71E-5
Out-of-State	3	CO_2				2.78	2.78	2.84
		CH_4				2.51	2.51	3.98
		N_2O				3.04E-3	3.04E-3	3.01E-3
Out-of-State	4	CO_2				9.13	9.13	9.13
		CH_4				7.37	7.37	10.09
		N_2O				0.06	0.06	0.06
Out-of-State	***Total***	**CO_2**	**7.27**	**31.09**	**41.68**	**27.06**	**27.06**	**27.08**
		CH_4	**64.55**	**22.14**	**23.53**	**35.43**	**50.43**	**64.43**
		N_2O	**0.06**	**0.15**	**0.19**	**0.08**	**0.08**	**0.08**
		CO_2e	**71.88**	**53.38**	**65.41**	**62.57**	**77.56**	**91.59**
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**	**31.09**	**41.68**	**27.13**	**27.16**	**27.18**
		CH_4	**64.55**	**22.14**	**23.53**	**50.09**	**67.54**	**81.55**
		N_2O	**0.06**	**0.15**	**0.19**	**0.08**	**0.08**	**0.08**
		CO_2e	**71.88**	**53.38**	**65.41**	**77.30**	**94.78**	**108.81**
Combustion	Combustion	CO_2	211.14	155.57	144.12	116.65	116.65	116.65
		CH_4	0.14	0.30	0.47	0.20	0.20	0.20
		N_2O	2.21	0.24	0.75	0.18	0.18	0.18
Well-to-combustion total	***Well-to-combustion total***	**CO_2**	**218.41**	**186.66**	**185.80**	**143.77**	**143.81**	**143.83**
		CH_4	**64.69**	**22.43**	**24.00**	**50.28**	**67.73**	**81.74**
		N_2O	**2.27**	**0.39**	**0.94**	**0.27**	**0.27**	**0.27**
Well-to-combustion total	***Well-to-combustion total***	**CO_2e**	**285.37**	**209.49**	**210.74**	**194.32**	**211.81**	**225.83**

[a] GWP factors are representative of IPCC 2013 (AR5 20-year GWPs), see Table 46.

Table D-3. 2021 Well-to-Combustion Fossil Fuel Emission Factors (lb/mmBtu)[a]

Stage	Out-of-State Stage #	Pollutant	Coal	Distillate	Gasoline	Natural Gas Low	Natural Gas Mid	Natural Gas High
Out-of-State	1	CO_2	5.91	13.0	11.3	6.30	6.30	6.27
		CH_4	0.77	0.22	0.19	0.19	0.37	0.47
		N_2O	2.2E-04	2.1E-04	1.8E-04	1.5E-05	1.5E-05	1.5E-05
Out-of-State	2	CO_2	1.36	18.1	30.4	7.26	7.26	7.26
		CH_4	4.0E-05	0.05	0.09	0.11	0.11	0.12
		N_2O	1.2E-05	3.6E-04	5.5E-04	6.5E-08	6.5E-08	6.5E-08
Out-of-State	3	CO_2				2.78	2.78	2.84
		CH_4				0.03	0.03	0.05
		N_2O				1.2E-05	1.2E-05	1.1E-05
Out-of-State	4	CO_2				9.13	9.13	9.13
		CH_4				0.09	0.09	0.12
		N_2O				2.2E-04	2.2E-04	2.2E-04
Out-of-State	***Total***	**CO_2**	**7.27**	**31.1**	**41.7**	**27.1**	**27.1**	**27.1**
		CH_4	**0.77**	**0.26**	**0.28**	**0.42**	**0.60**	**0.77**
		N_2O	**2.3E-04**	**5.8E-04**	**7.3E-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**	**31.1**	**41.7**	**27.1**	**27.2**	**27.2**
		CH_4	**0.77**	**0.26**	**0.28**	**0.60**	**0.80**	**0.97**
		N_2O	**2.3E-04**	**5.8E-04**	**7.3E-04**	**3.1E-04**	**3.1E-04**	**3.1E-04**
Combustion	Combustion	CO_2	211.1	155.6	144.1	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
		N_2O	8.4E-03	9.0E-04	2.8E-03	7.0E-04	7.0E-04	7.0E-04
Well-to-combustion total	***Well-to-combustion total***	**CO_2**	**218.4**	**186.7**	**185.8**	**143.8**	**143.8**	**143.8**
		CH_4	**0.77**	**0.27**	**0.29**	**0.60**	**0.81**	**0.97**
		N_2O	**8.6E-03**	**1.5E-03**	**3.6E-03**	**1.0E-03**	**1.0E-03**	**1.0E-03**

[a] Emissions shown as unadjusted without GWP factors applied.

Appendix E. Global Warming Potentials

The GWP factors used in generating the time series inventory are listed in Table E-1. As described in Section 1.2.2, use of 20-year GWPs is required under the Climate Act.

Table E-1. Global Warming Potentials (IPCC, 2013)

Species Name	Chemical Formula	GWP Values (AR4)		GWP Values (AR5)	
		20-year	100-year	20-year	100-year
Carbon dioxide	CO2	1	1	1	1
Methane	CH4	72	25	84	28
Nitrous oxide	N2O	289	298	264	265
PFC-14	CF4	5,210	7,390	4,880	6,630
PFC-116	C2F6	8,630	12,200	8,210	11,100
PFC-218	C3F8	6,310	8,830	6,640	8,900
PFC-318	C4F8	7,310	10,300	7,110	9,540
Sulfur hexafluoride	SF6	16,300	22,800	17,500	23,500
Nitrogen trifluoride	NF3	12,300	17,200	12,800	16,100
HFC-23	CHF3	12,000	14,800	10,800	12,400
HFC-32	CH2F2	2,330	675	2,430	677
HFC-125	CHF2CF3	6,350	3,500	6,090	3,170
HFC-134a	CH2FCF3	3,830	1,430	3,710	1,300
HFC-143a	CH3CF3	5,890	4,470	6,940	4,800
HFC-236fa	CF3CH2CF3	8,100	9,810	6,940	8,060
Biogenic CO2	Biogenic CO2	0	0	0	0

Appendix F. GHG Inventory Results

Table F-1. GHG Emissions (thousand MT CO_2e) by Sector for selected years, AR5-20 GWP. All results include biogenic CO_2, which is also shown separately for each sector.

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Electricity	Fuel Combustion	Coal	25,044	24,542	13,673	2,122	460	159	-
Electricity	Fuel Combustion	Distillate Fuel	473	1,026	274	358	163	77	89
Electricity	Fuel Combustion	Natural Gas	12,595	20,232	23,101	25,797	20,725	23,186	24,596
Electricity	Fuel Combustion	Petroleum Coke	-	166	539	-	-	-	-
Electricity	Fuel Combustion	Residual Fuel	25,452	10,781	847	919	171	100	400
Electricity	Fuel Combustion	Wood	68	591	444	703	602	611	576
Electricity Total, Fuel Combustion, Biogenic CO_2 only*			66	575	66	575	432	683	585
Electricity Total, Fuel Combustion			**63,631**	**57,339**	**38,878**	**29,898**	**22,121**	**24,134**	**25,661**
Electricity	Imported Fossil Fuels	Coal	6,741	3,639	3,886	758	161	69	-
Electricity	Imported Fossil Fuels	Distillate Fuel	154	337	92	123	52	25	29
Electricity	Imported Fossil Fuels	Natural Gas	11,523	20,385	25,412	24,092	16,299	17,960	19,220
Electricity	Imported Fossil Fuels	Petroleum Coke	-	34	112	-	-	-	-
Electricity	Imported Fossil Fuels	Residual Fuel	6,663	2,898	234	260	44	26	106
Electricity Total, Imported Fossil Fuels			**25,080**	**27,293**	**29,736**	**25,234**	**16,557**	**18,079**	**19,355**
Electricity	Net Electricity Imports - Fuel Combustion	All	914	6,981	8,114	3,738	4,700	3,669	5,275
Electricity	Electricity Imports - NJ - Fuel Combustion	All	-	2,067	2,337	2,813	3,113	2,829	3,116
Electricity Imports Total, Fuel Combustion, Biogenic CO_2 only*			6	160	6	2,227	2,456	2,813	3,113
Electricity Imports Total, Fuel Combustion			**914**	**9,048**	**10,451**	**6,550**	**7,814**	**6,498**	**8,391**
Electricity	Net Elec. Imports - Upstream Fossil Fuels	Coal	184	924	1,642	891	944	955	840
Electricity	Net Elec. Imports - Upstream Fossil Fuels	Distillate Fuel	7	37	26	20	29	26	52
Electricity	Net Elec. Imports - Upstream Fossil Fuels	Natural Gas	59	1,027	2,131	987	1,380	1,257	2,056
Electricity	Net Elec. Imports - Upstream Fossil Fuels	Petroleum Coke	1	0	-	-	-	-	-

Table F-1 continued

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Electricity	Net Elec. Imports - Upstream Fossil Fuels	Residual Fuel	19	56	12	0	0	1	1
Electricity	Elec. Imports - NJ - Upstream Fossil Fuels	Distillate Fuel	-	-	13	2	0	0	1
Electricity	Elec. Imports - NJ - Upstream Fossil Fuels	Natural Gas	-	3,528	2,439	2,023	1,681	1,450	1,674
Electricity	Elec. Imports - NJ - Upstream Fossil Fuels	Petroleum Coke	-	-	5	9	2	-	2
Electricity Imports Total, Upstream Fossil Fuels			**270**	**5,571**	**6,269**	**3,932**	**4,036**	**3,689**	**4,627**
Electricity Total			**89,895**	**99,251**	**85,335**	**65,616**	**50,528**	**52,401**	**58,034**
Residential	Fuel Combustion	Coal	167	35	-	-	-	-	-
Residential	Fuel Combustion	Distillate Fuel	13,772	15,542	8,598	9,159	7,946	5,841	7,688
Residential	Fuel Combustion	Kerosene	743	987	420	193	242	232	185
Residential	Fuel Combustion	LPG	910	1,385	1,407	1,423	1,791	1,619	1,620
Residential	Fuel Combustion	Natural Gas	18,609	22,115	21,408	24,929	26,098	24,119	24,547
Residential	Fuel Combustion	Wood	4,977	10,800	2,715	4,839	4,648	3,684	3,915
Residential Total, Fuel Combustion, Biogenic CO_2 only*			3,923	8,514	2,140	3,814	3,664	2,904	3,086
Residential Total, Fuel Combustion			**39,178**	**50,864**	**34,547**	**40,543**	**40,725**	**35,495**	**37,956**
Residential	Imported Fossil Fuels	Coal	35	4	-	-	-	-	-
Residential	Imported Fossil Fuels	Distillate Fuel	4,432	5,051	2,869	3,118	2,513	1,853	2,476
Residential	Imported Fossil Fuels	Kerosene	186	253	111	52	60	58	47
Residential	Imported Fossil Fuels	LPG	393	609	626	643	755	685	695
Residential	Imported Fossil Fuels	Natural Gas	16,957	22,198	23,467	23,197	20,445	18,609	19,105
Residential Total, Imported Fossil Fuels			**22,003**	**28,116**	**27,073**	**27,010**	**23,773**	**21,205**	**22,322**
Residential Total			**61,181**	**78,980**	**61,621**	**67,553**	**64,499**	**56,700**	**60,278**
Commercial	Fuel Combustion	Coal	528	221	7	-	-	-	-
Commercial	Fuel Combustion	Distillate Fuel	6,735	6,674	4,368	4,174	3,622	2,786	3,664
Commercial	Fuel Combustion	Kerosene	113	399	65	12	31	23	18
Commercial	Fuel Combustion	LPG	258	393	418	460	535	602	665
Commercial	Fuel Combustion	Natural Gas	10,736	20,217	15,755	17,157	17,786	15,942	16,407
Commercial	Fuel Combustion	Residual Fuel	8,330	4,514	3,751	149	56	43	90
Commercial	Fuel Combustion	Wood	544	1,806	353	708	671	659	702
Commercial Total, Fuel Combustion, Biogenic CO_2 only*			429	1,423	278	558	529	520	554

Table F-1 continued

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Commercial Total, Fuel Combustion			**27,245**	**34,224**	**27,245**	**34,224**	**24,718**	**22,661**	**22,702**
Commercial	Imported Fossil Fuels	Coal	141	33	2	-	-	-	-
Commercial	Imported Fossil Fuels	Distillate Fuel	2,168	2,169	1,458	1,421	1,145	884	1,180
Commercial	Imported Fossil Fuels	Kerosene	28	102	17	3	8	6	5
Commercial	Imported Fossil Fuels	LPG	112	173	186	208	226	254	285
Commercial	Imported Fossil Fuels	Natural Gas	9,782	20,293	17,271	15,966	13,934	12,300	12,769
Commercial	Imported Fossil Fuels	Residual Fuel	2,155	1,199	1,022	42	14	11	24
Commercial Total, Imported Fossil Fuels			**14,385**	**23,969**	**19,956**	**17,639**	**15,327**	**13,455**	**14,262**
Commercial Total			**41,630**	**58,193**	**44,674**	**40,300**	**38,029**	**33,509**	**35,807**
Industrial	Fuel Combustion	Coal - Coking	3,446	-	-	-	-	-	-
Industrial	Fuel Combustion	Coal - Other	4,422	4,060	1,953	1,423	846	384	510
Industrial	Fuel Combustion	Distillate Fuel	1,283	924	625	626	633	658	585
Industrial	Fuel Combustion	Kerosene	104	63	229	53	51	160	45
Industrial	Fuel Combustion	LPG	29	105	16	24	14	15	20
Industrial	Fuel Combustion	Natural Gas	5,388	5,103	3,987	4,354	4,630	4,427	4,590
Industrial	Fuel Combustion	Petroleum Coke	1,335	1,500	1,005	879	825	493	598
Industrial	Fuel Combustion	Residual Fuel	2,224	952	244	205	171	92	211
Industrial	Fuel Combustion	Special Naphthas	13	3	1	4	11	10	9
Industrial	Fuel Combustion	Wood	2,496	3,015	1,598	1,808	1,820	1,754	1,764
Industrial	Non-Energy Fuel Use	Asphalt and Road Oil	12	13	14	13	12	12	14
Industrial	Non-Energy Fuel Use	Coal - Coking	-	2,596	416	369	-	-	-
Industrial	Non-Energy Fuel Use	Coal - Other	20	34	19	18	15	8	11
Industrial	Non-Energy Fuel Use	Distillate Fuel	4	5	2	2	2	2	2
Industrial	Non-Energy Fuel Use	LPG	51	151	43	59	54	62	79
Industrial	Non-Energy Fuel Use	Lubricants	429	437	292	239	193	171	192
Industrial	Non-Energy Fuel Use	Lubricants (Transportation)	445	453	394	375	295	251	255
Industrial	Non-Energy Fuel Use	Misc. Petroleum Products	232	536	118	125	147	140	140

Table F-1 continued

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Industrial	Non-Energy Fuel Use	Natural Gas	88	87	50	71	124	117	121
Industrial	Non-Energy Fuel Use	Petroleum Coke	40	12	-	-	-	-	-
Industrial	Non-Energy Fuel Use	Special Naphthas	85	31	14	70	59	53	50
Industrial	Non-Energy Fuel Use	Waxes	33	36	14	9	8	7	9
Industrial Total, Fuel Combustion and Non-Energy Fuel Use, Biogenic CO_2 only*			2,400	2,898	1,536	1,738	1,750	1,686	1,696
Industrial Total, Fuel Combustion and Non-Energy Fuel Use			**22,179**	**20,116**	**11,035**	**10,726**	**9,910**	**8,818**	**9,206**
Industrial	Imported Fossil Fuels	Asphalt and Road Oil	604	666	745	737	611	626	721
Industrial	Imported Fossil Fuels	Coal	2,138	1,039	697	665	301	168	175
Industrial	Imported Fossil Fuels	Distillate Fuel	418	305	211	216	203	212	191
Industrial	Imported Fossil Fuels	Kerosene	26	16	61	14	13	40	12
Industrial	Imported Fossil Fuels	LPG	45	152	41	57	43	50	65
Industrial	Imported Fossil Fuels	Lubricants	166	172	116	97	73	65	54
Industrial	Imported Fossil Fuels	Lubricants (Transportation)	172	178	157	152	112	96	72
Industrial	Imported Fossil Fuels	Misc. Petroleum Products	62	146	33	36	39	37	38
Industrial	Imported Fossil Fuels	Natural Gas	5,100	5,355	4,547	4,244	3,861	3,639	3,806
Industrial	Imported Fossil Fuels	Petroleum Coke	276	310	211	189	163	98	121
Industrial	Imported Fossil Fuels	Residual Fuel	580	255	67	58	44	24	56
Industrial	Imported Fossil Fuels	Special Naphthas	49	18	8	41	34	31	30
Industrial	Imported Fossil Fuels	Waxes	18	20	8	5	5	4	4
Industrial Total, Imported Fossil Fuels			**9,654**	**8,633**	**6,903**	**6,510**	**5,502**	**5,090**	**5,345**
Industrial Total			**31,834**	**28,749**	**17,938**	**17,236**	**15,413**	**13,908**	**14,551**
Transp. - On-Road Motor Vehicles	Fuel Combustion	CNG	0	77	256	298	206	195	245
Transp. - On-Road Motor Vehicles	Fuel Combustion	Diesel	8,930	11,882	12,659	14,002	13,855	12,704	12,102

Table F-1 continued

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Transp. - On-Road Motor Vehicles	Fuel Combustion	Gasoline	51,234	60,708	55,122	53,793	50,453	40,086	44,132
On-road Transportation Total, Fuel Combustion, Biogenic CO2 only*			-	104	-	104	3,601	4,064	4,110
On-road Transportation Total, Fuel Combustion			**60,164**	**72,666**	**68,037**	**68,093**	**64,515**	**52,985**	**56,479**
Transp. - On-Road Motor Vehicles	Imported Fossil Fuels	CNG	0	50	247	215	46	42	48
Transp. - On-Road Motor Vehicles	Imported Fossil Fuels	Diesel	2,914	3,956	4,242	4,643	4,208	3,898	3,732
Transp. - On-Road Motor Vehicles	Imported Fossil Fuels	Gasoline	21,319	25,863	22,577	22,124	19,399	15,459	17,250
On-road Transportation Total, Imported Fossil Fuels			**24,233**	**29,869**	**27,067**	**26,982**	**23,653**	**19,399**	**21,030**
On-road Transportation Total			**84,397**	**102,536**	**95,104**	**95,075**	**88,167**	**72,384**	**77,508**
Transp. - Nonroad - Aviation	Fuel Combustion	Aviation Gasoline	62	44	15	28	33	28	30
Transp. - Nonroad - Aviation	Fuel Combustion	Jet Fuel	5,835	5,107	6,450	6,843	7,311	3,624	5,286
Transp. - Nonroad - Railroad	Fuel Combustion	Distillate Fuel	123	488	349	785	576	470	462
Transp. - Nonroad - Marine/Boating	Fuel Combustion	Distillate Fuel	105	174	74	360	296	266	251
Transp. - Nonroad - Marine/Boating	Fuel Combustion	Gasoline	447	602	515	725	801	876	1,010
Transp. - Military	Fuel Combustion	Distillate Fuel	120	51	197	30	13	33	20
Transp. - Military	Fuel Combustion	Residual Fuel	121	36	-	-	-	-	-
Transp. - Bunker (Vessel)	Fuel Combustion	Residual Fuel	496	4,196	5,015	2,547	425	513	892
Transp. - Bunker (Aircraft)	Fuel Combustion	Jet Fuel	11,579	8,286	10,344	12,617	13,667	6,164	7,427
Transp. - Nonroad - Other	Fuel Combustion	Diesel	486	516	361	250	468	347	295
Transp. - Nonroad - Industrial/Commercial	Fuel Combustion	Gasoline	130	120	347	952	1,020	1,038	1,045
Transp. - Nonroad - Construction	Fuel Combustion	Gasoline	202	86	310	75	74	75	70
Transp. - Nonroad - Agricultural	Fuel Combustion	Gasoline	127	160	237	19	11	11	12
Transp. - Nonroad - Public Nonhighway	Fuel Combustion	Gasoline	295	48	49	44	14	13	12
Transp. - Nonroad - Miscellaneous/Unclassified	Fuel Combustion	Gasoline	189	32	21	34	4	4	4

Table F-1 continued

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Non-road Transportation Total, Fuel Combustion			**22,100**	**21,958**	**26,716**	**28,674**	**28,116**	**16,720**	**20,554**
Transp. - Nonroad - Lawn and Garden	Fuel Combustion	Gasoline	1,060	1,118	1,124	1,132	1,206	1,224	1,242
Transp. - Nonroad - Recreational Vehicle	Fuel Combustion	Gasoline	465	488	487	490	557	568	539
Transp. - Nonroad - Pipelines	Fuel Combustion	Natural Gas	259	405	823	1,743	1,642	1,468	1,955
Non-road Transportation Total, Fuel Combustion, Biogenic CO_2 only*			-	5	199	275	309	297	312
Transp. - Nonroad - Aviation	Imported Fossil Fuels	Aviation Gasoline	15	11	4	8	8	7	8
Transp. - Nonroad - Aviation	Imported Fossil Fuels	Jet Fuel	1,508	1,335	1,730	1,887	1,842	917	1,362
Transp. - Nonroad - Railroad	Imported Fossil Fuels	Distillate Fuel	40	159	115	257	173	142	141
Transp. - Nonroad - Marine/Boating	Imported Fossil Fuels	Distillate Fuel	32	54	23	113	85	77	73
Transp. - Nonroad - Marine/Boating	Imported Fossil Fuels	Gasoline	188	255	206	293	301	330	386
Transp. - Military	Imported Fossil Fuels	Distillate Fuel	37	16	62	9	4	10	6
Transp. - Military	Imported Fossil Fuels	Residual Fuel	31	9	-	-	-	-	-
Transp. - Bunker (Vessel)	Imported Fossil Fuels	Residual Fuel	128	1,113	1,364	712	109	132	234
Transp. - Bunker (Aircraft)	Imported Fossil Fuels	Jet Fuel	2,992	2,167	2,775	3,479	3,444	1,560	1,914
Transp. - Nonroad - Other	Imported Fossil Fuels	Distillate Fuel	154	165	117	80	138	103	88
Transp. - Nonroad - Industrial/Commercial	Imported Fossil Fuels	Gasoline	53	49	132	365	365	372	380
Transp. - Nonroad - Construction	Imported Fossil Fuels	Gasoline	82	35	118	29	27	27	25
Transp. - Nonroad - Agricultural	Imported Fossil Fuels	Gasoline	53	67	93	8	4	4	5
Transp. - Nonroad - Public Nonhighway	Imported Fossil Fuels	Gasoline	120	20	19	17	5	5	4
Transp. - Nonroad - Miscellaneous/Unclassified	Imported Fossil Fuels	Gasoline	77	13	8	13	1	1	1
Transp. - Nonroad - Lawn and Garden	Imported Fossil Fuels	Gasoline	427	451	422	428	425	433	445

Figure F-1 continued

Emissions Category 1	Emissions Category 2	Fuel Type	1990	2000	2010	2015	2019	2020	2021
Non-road Transportation Total, Fuel Combustion			**22,100**	**21,958**	**26,716**	**28,674**	**28,116**	**16,720**	**20,554**
Transp. - Nonroad - Recreational Vehicle	Imported Fossil Fuels	Gasoline	187	198	185	188	199	204	196
Transp. - Nonroad - Pipelines	Imported Fossil Fuels	Natural Gas	237	409	908	1,633	1,295	1,140	1,532
Non-road Transportation Total, Imported Fossil Fuels			**6,361**	**6,526**	**8,281**	**9,519**	**8,423**	**5,465**	**6,801**
Non-road Transportation Total			**28,461**	**28,484**	**34,997**	**38,192**	**36,539**	**22,185**	**27,355**
Transportation Total			**112,858**	**131,019**	**130,101**	**133,268**	**124,707**	**94,569**	**104,863**
Oil and Gas Systems	Fugitive Emissions	All	18,262	17,556	19,524	16,840	15,516	15,161	14,888
Grand Total (AR5-20)			**355,659**	**413,748**	**359,192**	**340,813**	**308,690**	**266,247**	**288,421**

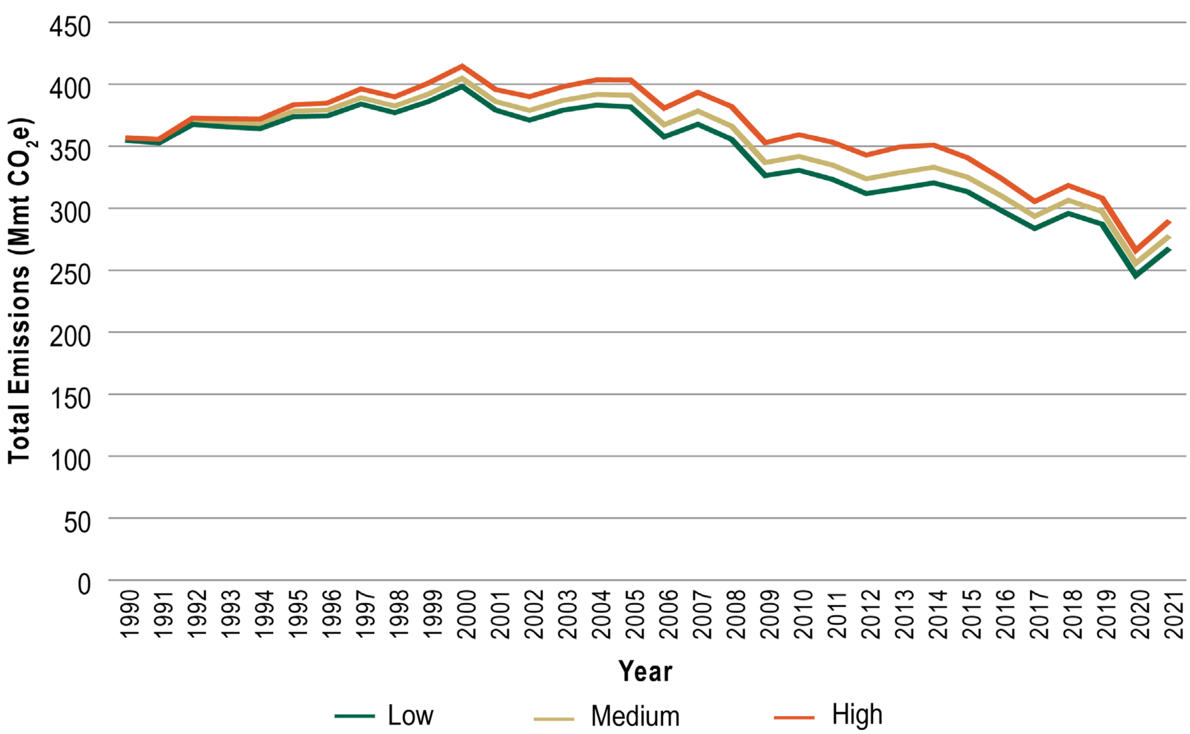
* Biogenic CO_2 results by sector for electricity, residential, commercial, and industrial reflect combustion of wood, while results for transportation sectors reflect biofuels (e.g., ethanol and biodiesel).

Appendix G. Results under Alternative Inventory Settings

G.1 Upstream Natural Gas Emission Factors

Figure G-1 tests the sensitivity of different natural gas approaches (described in Section 2.2.1.1) on total NYS energy emissions. By default, the inventory reflects the High natural gas upstream emission factor calculation approach. For 2021, the high approach yields 288.4 Mmt CO_2e total emissions; 278.4 Mmt CO_2e for the mid-approach (-4% from high); and 266.7 Mmt CO_2e for the low-approach (-8% from high).

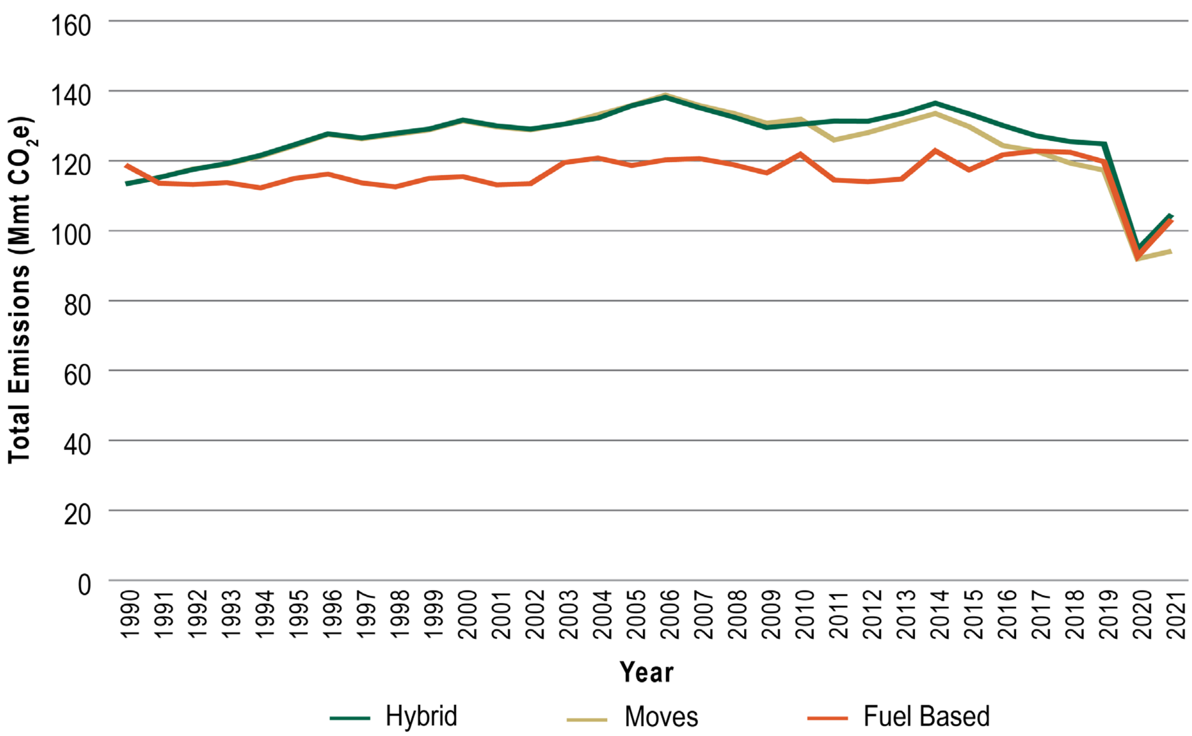
Figure G-1. Total NYS Energy Emissions, by Upstream Natural Gas Approach, Mmt CO2e, 1990–2021



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 (described in Section 2.1.5). By default, the inventory reflects the hybrid transportation assumptions. For the entirety of the time series, the 'hybrid' and 'MOVES' approaches track one another closely, while the 'Fuel Based' approach remains partially lower in its estimates. However, in 2021, the emissions values of all three approaches tend towards convergence with the Hybrid approach at 104.9 Mmt CO_2e; the MOVES approach at 94.1 Mmt CO_2e; and the Fuel Based approach at 103.1 Mmt CO_2e.

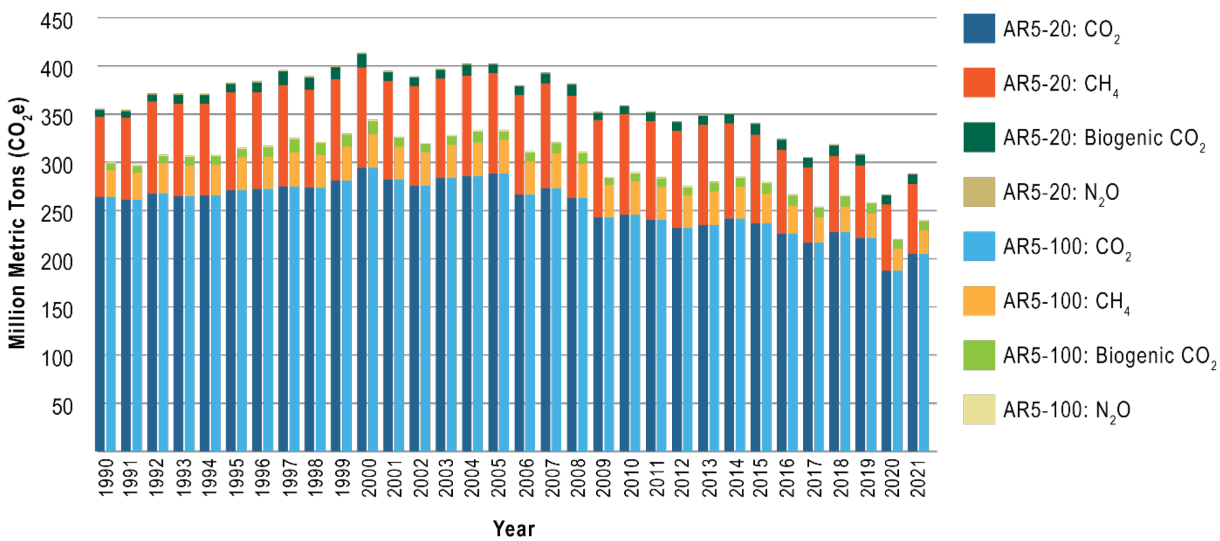
Figure G-2. Total NYS Transportation Sector Energy Emissions, by On-Road Transportation Input Approach, Mmt CO_2e*, 1990–2021*



G.3 Global Warming Potential Characterization Factors

Figure G-3 shows the effects of different GWP approaches on total NYS energy emissions, by gas type. By default, the inventory reflects AR5-20yr GWP. The notable drop in overall emissions from GWP-20 to GWP-100 is entirely driven by the difference in methane GWP multipliers from 84 under the 20-year time horizon to 28 in the 100-year (AR5).

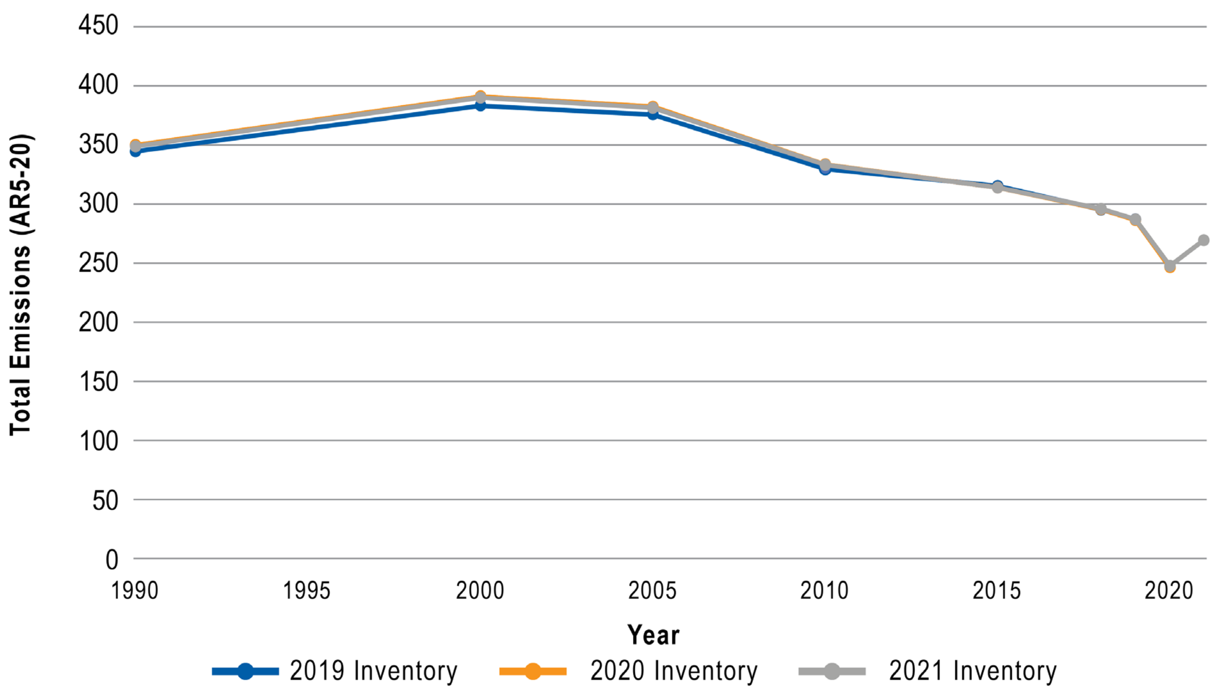
Figure G-3. Total NYS Energy Emissions, GWP-20 and GWP-100, by GHG



Appendix H. 2021 Data Year Results

Figure H-1 compares NYS energy emissions inventory results from the current 2021 inventory to the prior published inventory through data year 2019. Until 2010, the inventories convey slight differences in overall emissions, primarily driven by changes in U.S. EPA emissions modeling profiles for transportation fuels from MOVES2014b (used in the 2019 inventory) to MOVES3 (used in the 2020 inventory). There are no discernable differences in total emissions between the 2020 and 2021 inventory across the time series, as increases in emissions in the Oil and Gas sector were offset by small decreases in upstream emissions elsewhere.

Figure H-1. Change in Energy Emissions, Mmt CO_2e, From 2019 Inventory to 2021 Inventory



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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

NEW YORK STATE | NYSERDA

State of New York
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New York State Energy Research and Development Authority
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