The Los Angeles 100% Renewable Energy Study

Chapter 8. Greenhouse Gas Emissions

FINAL REPORT: LA100—The Los Angeles 100% Renewable Energy Study

March 2021

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Los Angeles Department of Water & Power

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The Los Angeles 100% Renewable Energy Study

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Context

The Los Angeles 100% Renewable Energy Study (LA100) is presented as a collection of 12 chapters and an executive summary, each of which is available as an individual download.

- The **Executive Summary** describes the study and scenarios, explores the high-level findings that span the study, and summarizes key findings from each chapter.
- **Chapter 1: Introduction** introduces the study and acknowledges those who contributed to it.
- **Chapter 2: Study Approach** describes the study approach, including the modeling framework and scenarios.
- **Chapter 3: Electricity Demand Projections** explores how electricity is consumed by customers now, how that might change through 2045, and potential opportunities to better align electricity demand and supply.
- **Chapter 4: Customer-Adopted Rooftop Solar and Storage** explores the technical and economic potential for rooftop solar in LA, and how much solar and storage might be adopted by customers.
- **Chapter 5: Utility Options for Local Solar and Storage** identifies and ranks locations for utility-scale solar (ground-mount, parking canopy, and floating) and storage, and associated costs for integrating these assets into the distribution system.
- **Chapter 6: Renewable Energy Investments and Operations** explores pathways to 100% renewable electricity, describing the types of generation resources added, their costs, and how the systems maintain sufficient resources to serve customer demand, including resource adequacy and transmission reliability.
- **Chapter 7: Distribution System Analysis** summarizes the growth in distribution-connected energy resources and provides a detailed review of impacts to the distribution grid of growth in customer electricity demand, solar, and storage, as well as required distribution grid upgrades and associated costs.
- **Chapter 8: Greenhouse Gas Emissions** (this chapter) summarizes greenhouse gas emissions from power, buildings, and transportation sectors, along with the potential costs of those emissions.
- **Chapter 9: Air Quality and Public Health** summarizes changes to air quality (fine particulate matter and ozone) and public health (premature mortality, emergency room visits due to asthma, and hospital admissions due to cardiovascular diseases), and the potential economic value of public health benefits.
- **Chapter 10: Environmental Justice** explores implications for environmental justice, including procedural and distributional justice, with an in-depth review of how projections for customer rooftop solar and health benefits vary by census tract.
- **Chapter 11: Economic Impacts and Jobs** reviews economic impacts, including local net economic impacts and gross workforce impacts.
- **Chapter 12: Synthesis** reviews high-level findings, costs, benefits, and lessons learned from integrating this diverse suite of models and conducting a high-fidelity 100% renewable energy study.

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Key Findings

The primary motivation for the Los Angeles City Council to request a study of pathways to reach 100% renewable electricity supply is the reduction of greenhouse gas (GHG) emissions.[1] In supporting the investigation into how to meet the 100% renewable goal, NREL has quantified for each scenario the changes to power-, buildings-, and light-duty-vehicle-sector GHG emissions associated with the LA100 scenarios. The study also evaluates potential costs associated with these emissions based on assumptions informed by NREL's LADWP partners.

For the power sector, GHG emissions are reported in two scopes: combustion-only carbon dioxide (CO_2) emissions and life cycle GHG emissions. NREL's power sector models report CO_2 emissions from the combustion of fossil fuels. In addition, based on a systematic review of extant literature, NREL has calculated GHG emissions (e.g., CO_2, methane, nitrous oxide and sulfur hexafluoride [SF_6]) attributable to the electricity generation in LA100 scenarios. These "life cycle" GHG emissions are composed of several "phases" of the life cycle of both the generation technology and fuels. These include not only combustion of fossil fuel (in the operation phase) but also construction and decommissioning of generation assets as well as ongoing non-combustion emissions related to the maintenance of the plant and the extraction, processing, and transport of fuel, where applicable. The latter is known as the "fuel cycle." When weighted by 100-year global warming potentials, GHG emissions are reported in carbon dioxide equivalents (CO_2e).

For non-power sectors that are influenced by LA100 scenarios—buildings (residential and commercial) and vehicles (light-duty and buses)—both combustion emissions and fuel cycle emissions are reported. When summing emissions for all three sectors (power, buildings, vehicles), for simplicity, we refer to them together as "life cycle" despite not including all life cycle phases for buildings and vehicles.

Considering all GHG emissions attributable to power and non-power sectors associated with LA100 scenarios (life cycle GHG emissions), how much do they differ by LA100 scenarios?

- The Early & No Biofuels – High scenario exhibits the lowest cumulative (2020–2045) life cycle GHG emissions attributable to the LA100 scenarios, at just under 400 million metric tons (MMT) CO_2e. The SB100 – Moderate scenario has the highest, at approximately 570 MMT CO_2e (see Figure 1).
- Fuel use and associated fuel cycle emissions from the vehicle sector account for between 51% (SB100 – Stress) and 64% (Early & No Biofuels – High) of cumulative GHG emissions. Power sector GHG emissions account for between 13% (Early & No Biofuels – Moderate) and 32% (SB100 – Stress) of cumulative GHG emissions. Fuel use and associated fuel cycle emissions from the building sector account for between 16% (SB100 – High) and 24% (Early & No Biofuels – Moderate) of cumulative GHG emissions.
- By 2045, all LA100 scenarios show significantly lower annual life cycle GHG emissions compared to 2020 for the sources analyzed. The Early & No Biofuels – High scenario is estimated to have the

[1] LA City Council (March 2016) Motion 16-0243. https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB689137&RevisionSelectionMethod=LatestReleased

highest reduction of annual life cycle GHG emissions in 2045 relative to 2020 (88% lower). Approximately 20% of the 4 MMT CO_2e/year of 2045 annual life cycle GHG emissions in the Early & No Biofuels – High scenario are from the power sector, 16% are associated with fuel use in the buildings sector, and 64% are associated with fuel use by the vehicle sector (light-duty vehicles and buses).

- 2045 annual life cycle GHG emissions are highest in the SB100 – Moderate scenario, at 16 MMT CO_2e/year (54% lower than in 2020). Approximately 18% of the 2045 annual life cycle GHG emissions in the SB100 – Moderate scenario are from the power sector, 25% are associated with fuel use in the buildings sector, and 57% are associated with fuel use in the vehicle sector.

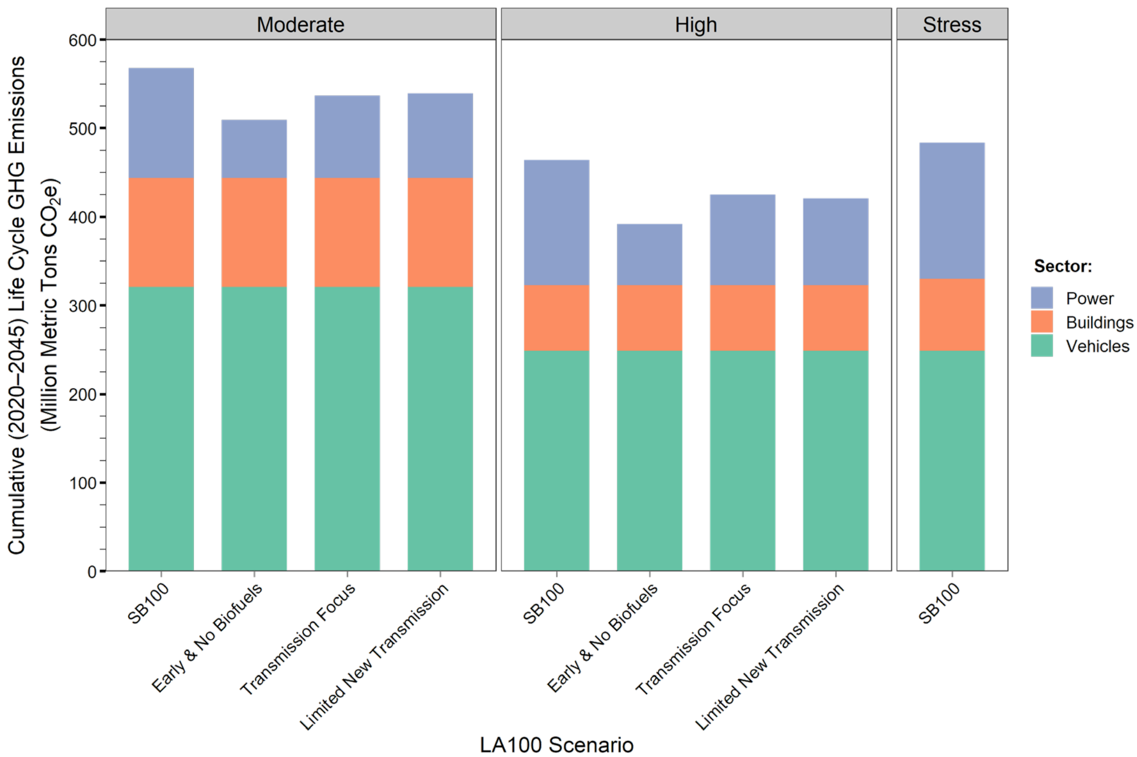


Figure 1. Life cycle (power sector) and fuel cycle (buildings, transportation) cumulative GHG emissions associated with each LA100 scenario, by load projection (Moderate, High, Stress), 2020–2045

By how much do GHG emissions from LADWP's in-basin electricity generation change under different LA100 scenarios?

- All LA100 scenarios show significant cumulative (2020–2045) combustion GHG emission declines compared to a hypothetical case where current generation and associated annual emissions are held constant, ranging from an approximately 53% reduction for SB100 – Stress to an 86% reduction for Early & No Biofuels – Moderate.
- Across all scenarios, combustion GHG emissions from coal generation initially dominate at about 8 MMT CO_2/year, before quickly dropping off after 2025, leaving natural gas-fired power plants to account for the remaining, if any, combustion emissions from 2030 onward (see Figure 2).

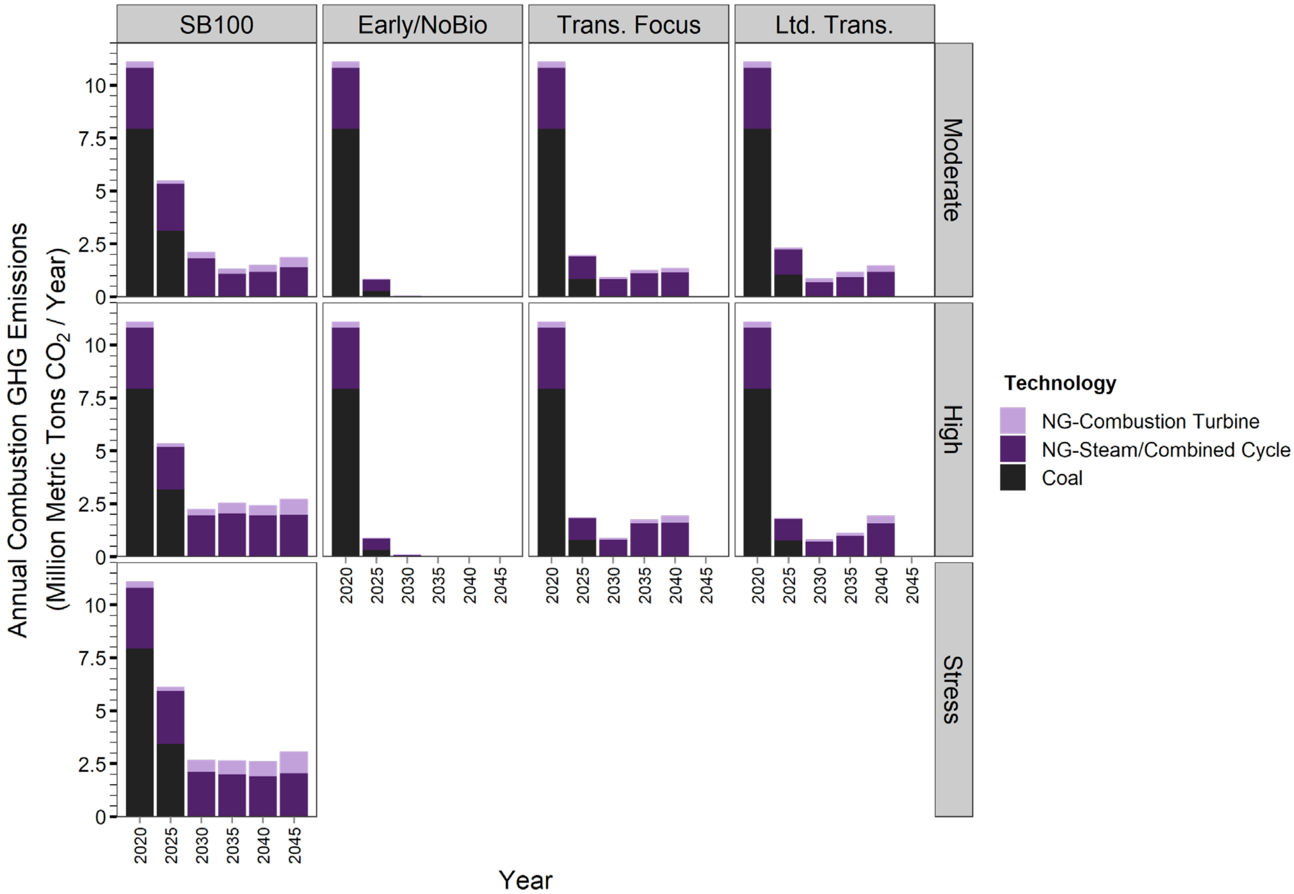


Figure 2. Combustion CO_2 emissions for each LA100 scenario, by year and technology type

- The Early & No Biofuels set of scenarios has the lowest annual life cycle GHG emissions in 2045, at 0.6–0.9 MMT CO_2e/year, or about 80% lower than those of the SB100 set.
- Power sector GHG emissions from life cycle phases outside of fossil fuel combustion (which include construction, decommissioning, and ongoing non-combustion such as maintenance of generator facilities and fuel extraction) account for between 33% and 58% of cumulative (2020–2045) emissions.
- Because Early & No Biofuels reaches the 100% renewable energy target ten years earlier, this scenario has the lowest cumulative life cycle GHG emissions for the power sector in the study period, at approximately 65–69 MMT CO_2e, or about half those of the SB100 set.

By how much do GHG emissions from non-power sectors (selected transportation and buildings sources) change under different LA100 scenarios?

- Complementing the power-sector GHG impact analysis, consideration of the non-power sector GHG emissions include those from fossil fuels used in residential and commercial buildings as well as in the light-duty vehicle and bus fleets, as modeled within LA100. All major combusted fuels are included: natural gas used in buildings (both commercial and residential) for space and water heating and cooking, and gasoline and diesel used in light-duty vehicles as well as diesel, natural gas, and propane used in urban transit and school buses. Both combustion-only and fuel cycle GHG emissions are included.

- Due to higher levels of end-use electrification, life cycle GHG emissions associated with natural gas consumption in the buildings sector under the High load projection are significantly lower than under the Moderate projection—a reduction equivalent to the annual emissions generated by 5.7 million average U.S. homes' energy usage.
- Reductions in natural gas usage in residential buildings in the High and Stress load projections equates to approximately 86% reduction in annual GHG emissions from 2020 to 2045 for both projections. The commercial building results are similar.
- Across all three load projections, combustion emissions account for approximately 78% of the cumulative life cycle GHG emissions from fuel use in the residential building sector, with the remaining 22% attributed to the fuel cycle (extraction, processing and transport of fuels), similar to commercial buildings.
- Compared to 2020, the Moderate EV adoption projection reduces annual life cycle GHG emissions from fuel used in light-duty vehicles and buses by approximately 48% in 2045; the High EV adoption projection reduces GHG emissions by approximately 85%. These reductions are equivalent to those generated by the consumption of 1.0 billion and 1.7 billion gallons of gasoline, respectively.
- The fuel cycle (extraction, processing, and transport of vehicle fossil fuels) accounts for about 31% of the total cumulative (2020–2045) life cycle GHG emissions from light-duty vehicles and buses in both the Moderate and High EV adoption projection scenarios.
- Passenger cars and light-duty trucks account for almost all (99%) of annual life cycle GHG emissions associated with fuel consumption from vehicles considered within the LA100 study, with the two bus fleets contributing negligible annual emissions.

What are the economic costs associated with the GHG emissions from the LA100 scenarios, and what is the relative contribution of each affected sector?

- Monetized costs of LA100 scenarios differ by discount rates: the cost of future emissions have in current dollars. Under the 3% central case set by the Interagency Working Group on the Social Cost of Carbon, these cumulative costs of emissions (2020–2045) range from a low of $31 billion under Early & No Biofuels – High to a high of approximately $44 billion under SB100 – Moderate—a difference of approximately $13 billion between the scenarios.
- Cost levels of GHG emissions are primarily driven by electrification rather than by differences among the power sector scenario, and under each scenario, regardless of level of electrification, vehicles are the largest component. The portion comprised by vehicles ranges from a low of 51% under SB100 – Stress to a high of 63% under both Early & No Biofuels scenarios. Costs of GHG emissions from buildings exceed those of the power sector under Moderate scenarios, while the opposite is true under High scenarios (Figure 3).
- Within the power sector the lowest cumulative GHG costs by 2045 are approximately $5.2 billion under the Early & No Biofuels – Moderate scenario while the highest ($12 billion) are under the SB100 – Stress scenario at a 3% discount rate. Costs of buildings-related GHGs range from approximately $5.7 billion under High electrification to $9.6 billion under Moderate.

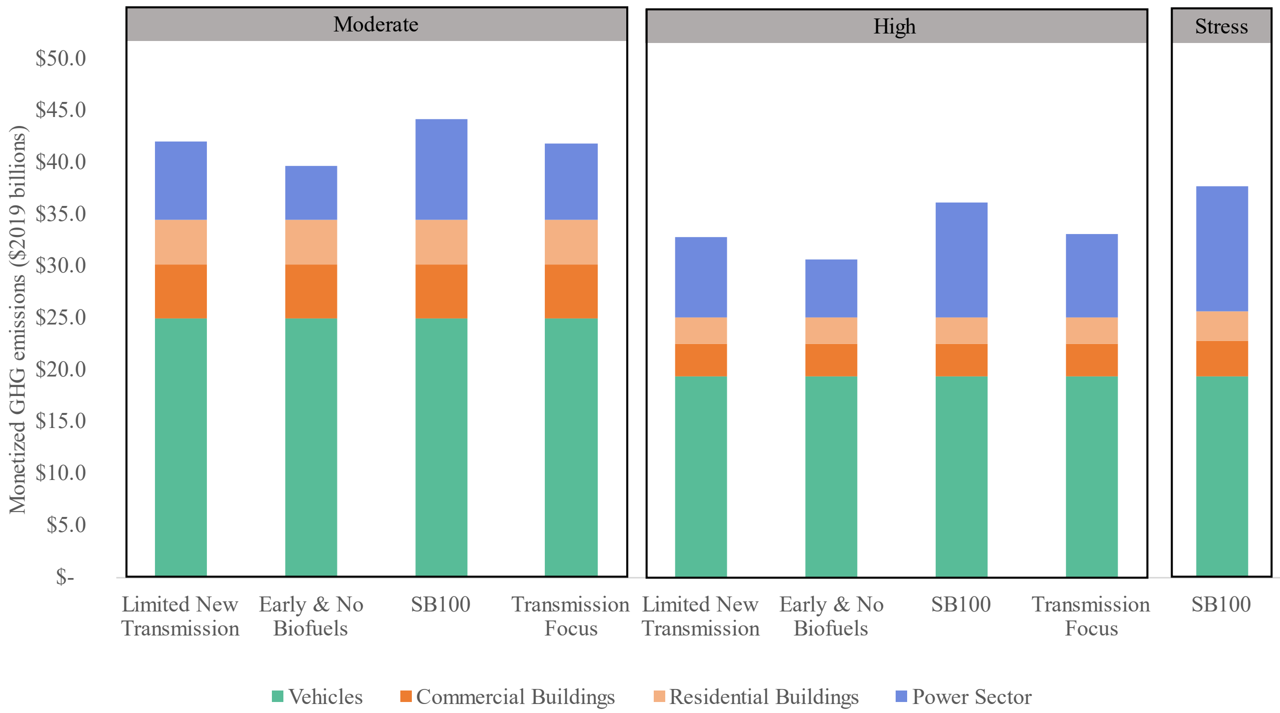


Figure 3. Cumulative monetized costs of life cycle GHG emissions (2020–2045) under a 3% (central case) discount rate

Important Caveats

1. While accounting for changes to GHG emissions associated with generation technologies, we do not consider GHG emissions from other electric infrastructure (e.g., transmission lines, distribution lines, substations). This caveat is especially important for the Transmission Focus scenario.

2. Charging of energy storage technologies occurs through grid electricity, and thus the GHG accounting of power sector emissions captures the emissions associated with operation of energy storage (both batteries and hydrogen produced by electrolysis).

3. Greenhouse gas emissions accounting assesses the electric-sector life cycle and changes to fuel use due to efficiency and electrification in residential and commercial buildings and light-duty vehicles and buses. The GHG accounting includes the full life cycle of emissions associated with electricity generation technologies, including construction and operation of the power plants and their decommissioning as well as emissions associated with combustion and the fuel cycle (extraction, processing, and transport of fuels). We do not account for life cycle GHG emissions associated with any changes to infrastructure outside of the power sector (e.g., equipment to electrify buildings or vehicles, charging stations). For vehicles and buildings, only emissions associated with fuel combustion and the fuel cycle (fuel extraction, processing, and transport) are considered.

4. GHG emissions from operations are analyzed cumulatively in 5-year timesteps (2020–2045).

5. GHG emissions are reported in the aggregate in terms of carbon dioxide equivalent.

6. Long-duration storage is assumed to be represented by hydrogen (H_2) storage combined with fuel cell regeneration.
7. Combustion turbines burning hydrogen are assumed to have the same upstream and downstream emissions as conventional natural-gas combustion turbines and the same non-combustion emissions as fuel cells. H_2 combustion turbines have no combustion phase GHG emissions because the H_2 burned is derived from renewable electricity.
8. The study reports net GHG reductions but does not create a marginal cost curve for GHG reductions as our analyses of costs and emissions do not align 1-to-1 in scope (i.e., costs include investments unrelated to GHG mitigation).
9. While modeling estimates for monetized impact multipliers by discount rate and year account for thousands of different combinations of possible future outcomes as a result of GHG emissions, these are still subject to inherent modeling limitations and not representative of all foreseeable costs.
10. Dollar values assigned to GHG emissions over time are from a 2017 study of economic damages of greenhouse gas emissions; future revisions of these figures in response to developments in research and understanding of physical and social science will likely drive changes over time.
11. Monetization of GHGs are values that can be modeled and quantified using objective criteria and do not include subjective values such as an individual's willingness to pay for changes in quality of life due to changes associated with GHG emissions.

1 Introduction

The primary motivation for the Los Angeles City Council to request a study of pathways to reach 100% renewable electricity supply is the reduction of greenhouse gas (GHG) emissions.[2] In supporting the investigation into how to meet the 100% renewable goal, NREL has quantified for each scenario the changes to power-, buildings-, and light-duty vehicle-sector GHG emissions associated with the LA100 scenarios. The study also evaluates potential costs associated with these emissions based on assumptions informed by the LADWP partners.

This chapter is structured as follows: we begin by introducing the methodology used for each of the sectors (power, buildings, and light-duty vehicles) considered in this analysis. Next, we present sector-specific results for these three sectors. Then, we present aggregated results summarizing emissions considering all three sectors. The projected costs of GHG emissions are presented last. The chapter closes with a description of the major assumptions, caveats, and limitations pertaining to the GHG analyses. Appendix A and Appendix B provide more in-depth discussion of the power sector and non-power sector methods, respectively. Appendix C through Appendix E present the emissions results from each sector in tabular format. Appendix F provides additional tables for the monetization results.

The following sections introduce the scope and briefly outline the methods used to calculate GHG emissions and potential costs of the emissions in the power, buildings, and light-duty vehicle sectors for the LA100 study.

Context within LA100

This chapter is part of the Los Angeles 100% Renewable Energy Study (LA100), a first-of-its-kind power systems analysis to determine what investments could be made to achieve LA's 100% renewable energy goals. Figure 4 provides a high-level view of how the analysis presented here relates to other components of the study. See Chapter 1 for additional background on LA100, and Chapter 1, Section 1.9, for more detail on the report structure.

[2] LA City Council (March 2016) Motion 16-0243. https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB689137&RevisionSelectionMethod=LatestReleased

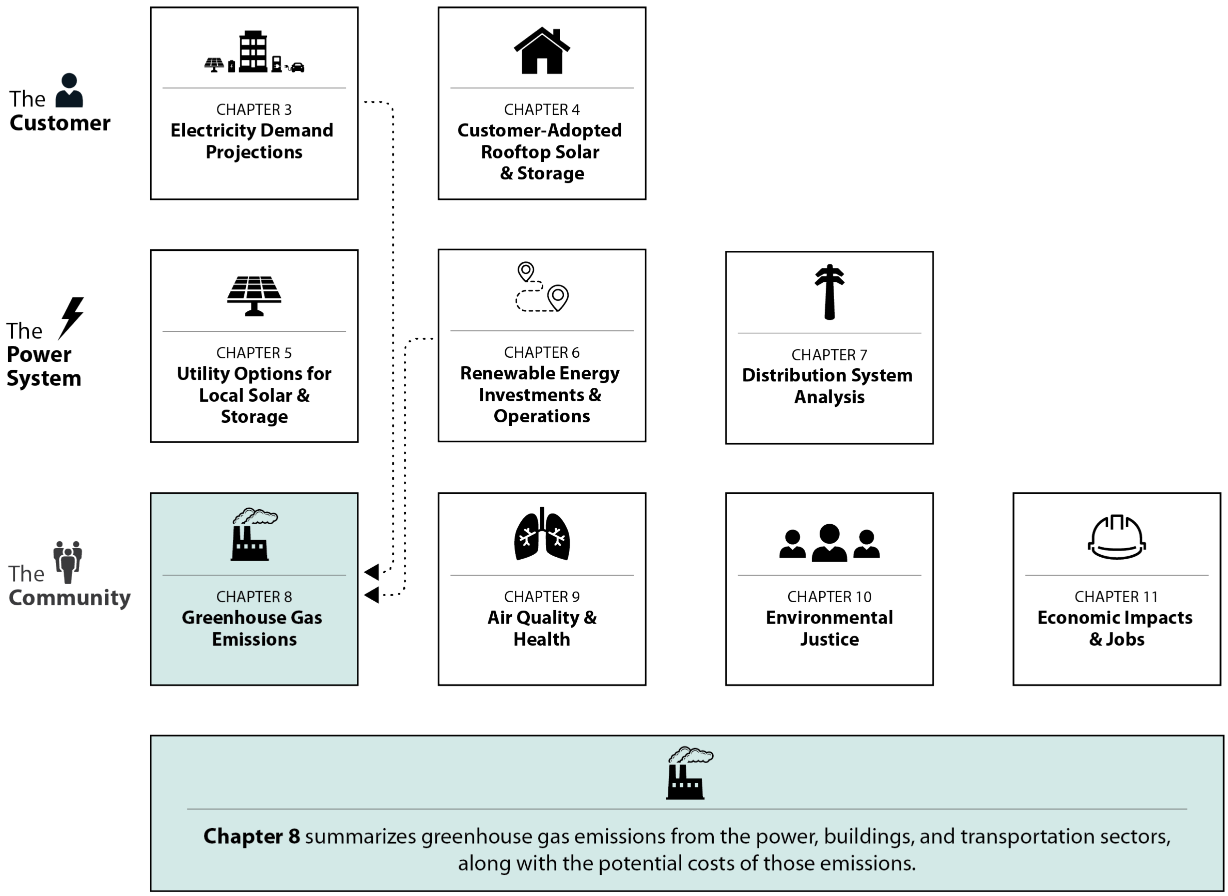


Figure 4. Overview of how this chapter, Chapter 8, relates to other components of LA100

Chapters 3 and 6 provide data and analysis that serve as inputs to the emissions results in this chapter.

2 Methodology

2.1 Power Sector

The analysis of power-sector GHG impacts for the various LA100 scenarios was conducted using the same approach as that employed in previous flagship analyses of renewable penetration undertaken at NREL, including the Renewable Electricity Futures study (NREL 2012), Wind Vision (DOE 2015), Hydropower Vision (DOE 2016), and Geothermal Vision (DOE 2019). As in those studies, we first present results from direct combustion only, which are the emissions directly emitted by LADWP-owned facilities generating electricity. We also account for all emissions attributable to LADWP-owned electricity generation in what is known as a life cycle assessment (LCA). An LCA considers all GHG emissions (as well as other environmental metrics like water use or non-GHG air pollutant emissions) that result from the generation of electricity even when not emitted by the plant owner. LCAs involve the estimation of GHG emissions at each phase of a generator's life cycle: plant construction (also known as "upstream," which includes resource extraction, component manufacturing and on-site construction); plant operation emissions including ongoing combustion (if applicable) and ongoing non-combustion activities like plant operation and maintenance (O&M) as well as emissions from the acquisition, treatment, and transport of fuels, when applicable (the so-called "fuel cycle"); and finally plant decommissioning and disposal (also known as "downstream"). In this way, LCAs account for what are known as "embodied emissions"—those emissions that occur prior to the activity being evaluated (here, the generation of electricity) yet are attributable to that activity—for instance, emissions from how fuels like natural gas are extracted and transported and from the manufacturing of solar panels. Accounting for all attributable emissions for all generation technologies ensures that comparisons made between technologies are fair and consistent, and that the choices utilities like LADWP make about which generation technologies to deploy comprehensively account for all associated GHG emissions.

The GHG emissions accounting approach used in this study quantifies these emissions from all generators, technologies, years, and life cycle phases as well as all relevant GHGs (e.g., CO_2, methane, nitrous oxide and sulfur hexafluoride (SF_6)). We report these results both as totals for a given LA100 scenario and disaggregated for insight into the origin of total emissions. A short description of this approach as applied to the LA100 study follows; more detail can be found in the accompanying Appendix A. Throughout this analysis, comparisons to several relevant baselines are made; these include "eGRID," "IRP," and "2020." eGRID refers to a flat extrapolation of 2018 emissions levels attributed to LADWP assets through the study period (2020–2045); IRP refers to LADWP's 2017 Integrated Resource Plan; 2020 refers to results for the first modeled year of the study period (2020–2045). Each of these baselines is described in more detail in the relevant portions of the power sector results.

First, generation and capacity addition/decommission outputs from the study's production cost modeling, as described in Chapter 6, were obtained for each model solve year (2020–2045 in 5-year timestep increments). Generation (which is an ongoing activity) is reported in units of kilowatt hours (kWh) and capacity additions/decommissions (which is a one-time activity) in units of megawatts (MW); both are reported on a generator-specific basis, which means the generator technology type is known. In order to determine the GHG emissions associated with each life cycle phase, phase- and technology-specific emissions factors (grams of carbon dioxide equivalent per unit of generation or capacity) are applied to these generation and capacity outputs for the ongoing and one-time life cycle phases, respectively. The emissions factors used in this study are up-to-date, median estimates obtained from a series of systematic literature reviews, maintained by NREL for nearly a decade, first undertaken as part of the LCA Harmonization project.[3] LCA literature was screened for inclusion of all important GHGs relevant to each technology; for instance, emissions of methane had to have been evaluated in studies of natural gas or coal generation.

Given the importance of storage in the LADWP 100% renewable energy pathways, two new technologies have been added to those assessed in the LCA Harmonization study to estimate the latest median emissions factors for lithium-ion batteries and hydrogen storage. See Appendix A for more detail on the approach used for these literature reviews. Once emissions factors have been applied to the generation and capacity outputs from production cost modeling, the remaining step is to aggregate the data into summary tables and figures. A selection of these results is presented in Section 3.

2.2 Non-Power Sectors

An important aspect of the LA100 study is considering changes to load sectors in ways that could impact where, how much, and in what sectors power is required in the future. Electrification of end uses that currently utilize combustion of fossil fuels, especially when combined with decarbonization of electricity supply, results in additional GHG emission reduction benefits attributable to the LA100 projections being investigated. The quantification of these additional GHG emission reductions of the LA100 projections is the subject of this section.

Broadly, this study uses an analogous approach for quantifying GHG emissions from the non-power sectors as for the power sector, with some important exceptions. Like for the power sector, our non-power sector GHG emission accounting considers fossil fuel use in all years from 2020 to 2045, both annually and cumulatively. As stated above, we are tracking fossil fuels used in residential and commercial buildings as well as in the light-duty vehicle and bus fleets that are modeled within LA100. We consider all major fuels combusted: natural gas used in buildings (both commercial and residential) for space and water heating and cooking, and gasoline used in light-duty vehicles as well as diesel, natural gas, and propane used in urban transit and school buses. The GHGs considered for each fuel are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOC), and carbon monoxide (CO).[4]

Like for the power sector, non-power sector GHG emissions are considered on a direct combustion emission and a life cycle basis. As a brief reminder (for more complete description, see Appendix B), the direct-combustion phase only considers the actual combustion of the fuel, whereas the "life cycle" phase includes GHG emissions from all the other activities needed to

[3] See Heath and Mann (2012); "Life Cycle Assessment Harmonization," NREL, https://www.nrel.gov/analysis/life-cycle-assessment.html.

[4] Other potential GHGs, such as black carbon, organic carbon, and nitrous oxides (NOx), are listed in the CA-GREET3.0 model developed by the California Air Resources Board (CARB) but are not included in the final GHG emission factors used here. This is the default assumption of the CA-GREET3.0 model and aligns with the requirements of the California Low Carbon Fuel Standard (LCFS), which does not count GHG emissions from black carbon, organic carbon, or NOx.

extract, process, and transport the fuel. Together, these other "non-combustion" aspects of fuel consumption are known as the "fuel cycle" and contribute a non-negligible impact to total GHG impacts.

The important distinction between the power sector life cycle GHG emissions accounting and non-power sector GHG emissions accounting is that the infrastructure in which the fuel is combusted is considered in our power sector analysis, but not considered for our non-power sector analysis. The construction and decommissioning of generation assets (named the "upstream" and "downstream" life cycle phases, respectively, as used in the power sector modeling) contribute modest GHG emissions to the overall impacts. This simplified approach is used in the non-power sector analysis because the additional infrastructure turnover modeling and detailed GHG accounting required to quantify embodied GHGs from constructing/manufacturing all the different types of vehicles and end-use appliances in buildings as well as buildings, recharging stations, etc., let alone their end-of-life disposal, is infeasible. As with the power sector, the vast majority of GHG emission attributable to non-power sector activities is from fossil fuel combustion, as has been shown in prior analysis such as for the Geothermal Vision report.[5]

GHG emissions from fossil fuels used in buildings and vehicles modeled in LA100 are estimated as the product of fuel use "activity" (e.g., gallon, mcf) and GHG emissions per unit of fuel used (i.e., "emissions factor"). The methods used for estimating fuel use in the non-power sector, as well as the corresponding GHG emission factors, have been selected to align with methods approved by the State of California. The models we use for determining baseline and projected GHG emissions are specific to the State of California, and to the Los Angeles metropolitan area when more specific inputs are available. The tools used to estimate non-power fuel use—EMFAC,[6] EVI-Pro,[7] and CA-GREET[8]—have been used to estimate power sector GHG emissions from the LA100 study, or are tools developed by the California Air Resources Board (CARB). These methods and tools are discussed in greater detail in Appendix B. The non-power sector results are presented in Section 4.

2.3 Monetization

Greenhouse gas emissions, while inherently global, can be monetized due to their contributions to climate change and associated damages in areas such as industry and agricultural productivity, real estate values, and health (Ackerman and Stanton 2012; Pizer et al. 2014; Greenstone, Kopits, and Wolverton 2013). Estimating costs of these emissions over time provides important context about the broader impact of different capacity expansion, generation, and development scenarios. Estimates over time do provide a limitation as well in that they are solely over a set period and any costs beyond that period as a result of modeled scenarios, regardless of their probability, are not included.

[5] "GeoVision," DOE, https://www.energy.gov/eere/geothermal/geovision.
[6] Name derives from the term "emissions factor:" "EMFAC," CARB, https://arb.ca.gov/emfac/.
[7] "CEC EV Infrastructure Projection Tool (EVI-Pro)," NREL, https://maps.nrel.gov/cec/.
[8] California-specific version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model: "CA-GREET3.0 Model and Tier 1 Simplified Carbon Intensity Calculators," CARB, https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

The U.S. Office of Management and Budget and Council of Economic Advisers convened a working group of federal agencies in 2009 to compile research on the costs and benefits of carbon dioxide and other greenhouse gas emissions. These agencies, along with experts from The Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of the Interior, Department of Transportation, Department of the Treasury, Environmental Protection Agency, National Economic Council, Office of Science and Technology Policy, participated in monetizing GHGs by developing different factors that can be applied to units of greenhouse gas or greenhouse gas equivalents emitted. These estimates were developed for use in cost-benefit and regulatory analysis and were selected in consultation with LA partners.

This group, the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG), provided estimates based on a combination of peer-reviewed academic literature and estimates from integrated assessment models (IAMs). All levels of government in the United States use these estimates when quantifying the cost of CO_2 emissions or either the relative cost of savings of different scenarios compared to one another.

The most recent estimates are from 2017 and reflect the latest academic literature (Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) 2017). The IWG used three IAMs: the Dynamic Integrated Climate Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

These IAMs have been in development since as early as 1977 (Newbold 2010) and represent relationships between populations, industries, and the environment. Each incorporates different relationships and different assumptions about factors such as changes in technology and how populations or consumers behave. Each model represents different subsets of the relationships and each incorporates a different methodology to produce results. So while they are similar types of models the estimates do not rely on a single set of assumptions or a narrow set of relationships.[9]

The IWG ran each scenario a large number of times while changing inputs to reflect uncertainty. The latest estimates generated 150,000 estimates from 10,000 simulations. Estimates were then compiled using central point estimates from all simulations. These estimates are presented at three discount rates: 5%, 3%, and 2.5%.[10] Discounting these figures represents the relationship between future impacts and present-day dollar values. The 2.5% discount rate on the low end assumes that future impacts are closer to 2019 dollar levels than the 5% rate, which assumes that

9 For more information about DICE see Newbold (2010), for FUND see (Anthoff and Tol 2014), and PAGE see Hope et al. (1993), and Hope (2013). IWG (2017) uses the DICE 2010, FUND 3.8, and PAGE 2002 versions of each model.

10 IWG (2017) additionally presents an extreme case of the 3% rate, the “high impact” scenario. Each rate carries some variability, with the average presented in the report for each. The additional scenario is for the 95th percentile of the 3% rate – its top end. Rather than show the average across models simulations, this additional figure provides an extreme case under the central rate. This is not included in this chapter because it is inconsistent with how the estimates from the 2.5% and 5% rates are presented and because it is more informational than representative of how the output of the IAMs and simulations should be interpreted.

future values are lower. IWG (2017) presents these three rates but considers 3% to be the central estimate. Table 1 shows these estimates for 2035 through 2045.

Table 1. IWG Social Cost of Carbon Estimates (2019$)

Discount Rate	5%	3%	2.5%
2035	$22	$67	$95
2040	$26	$73	$102
2045	$28	$78	$108

The monetization factors developed by the IWG is for carbon dioxide. The figures presented in this study are applied to carbon dioxide equivalents, so they include both CO_2 and non-CO_2 emissions. These life cycle estimates capture both combustion and non-combustion emissions.

These estimates rely on research and scientific modeling conducted up until their publication in 2017. As such, they are likely to change over time with further developments and understanding in physical science such as climate modeling and social science such as economics and sociology. Expectations about changes in productivity, for example, are constantly changing. These estimates may be tied to general trends in technological growth, but specific changes cannot always be anticipated and these changes can influence model outcomes. Similarly, developments in climate modeling provide a better understanding of how and what environmental changes may occur as a result of GHG emissions.

3 Power Sector GHG Emission Results

The power sector results figures presented in this chapter were derived from a suite of bulk power system modeling results, as described in Chapter 6. The LA100 scenarios included in this suite are as follows:

- SB100 – Moderate, High, and Stress Load Electrification
- Early & No Biofuels – Moderate and High Load Electrification
- Transmission Focus – Moderate and High Load Electrification
- Limited New Transmission – Moderate and High Load Electrification

3.1 Combustion Phase GHG Emission Results

GHG emissions are produced from the burning of fossil fuels, including coal and natural gas, to generate electricity; these processes constitute the combustion phase. Figure 5 compares cumulative (2020–2045) combustion GHG emissions for the LA100 scenarios and a baseline comparison calculated from reported combustion emissions in the eGRID 2018 database (EPA 2020). This baseline assumes that the rate of combustion emissions by LADWP-owned[11] generation resources in 2018 (an estimated 8.6 million MMT CO_2e/year) continues and is constant from 2020 through 2045. Relative to this baseline, cumulative (2020–2045) combustion emissions reductions are substantial across all LA100 scenarios, ranging from 117 MMT CO_2e or −53% (SB100 – Stress) to 191 MMT CO_2e or −86% (Early & No Biofuels – Moderate). For context here and throughout the report, 1 MMT CO_2e/year is roughly equivalent to the emissions from a coal-fired power plant operating for four years, or those from 216,000 passenger vehicles driven for one year.[12] While simple to conceptualize, it is important to remember that this eGRID baseline does not take into account projected load growth through the study period, whereas all LA100 scenarios do assume load growth trajectories.

[11] Combustion emissions for the two coal generation resources partly owned by LADWP—Navajo Generating Station and Intermountain Power Plant—are apportioned by their respective LADWP ownership fraction. Note that Navajo Generating Station formally ceased generation in November 2019.
[12] "Greenhouse Gas Equivalencies Calculator," EPA, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

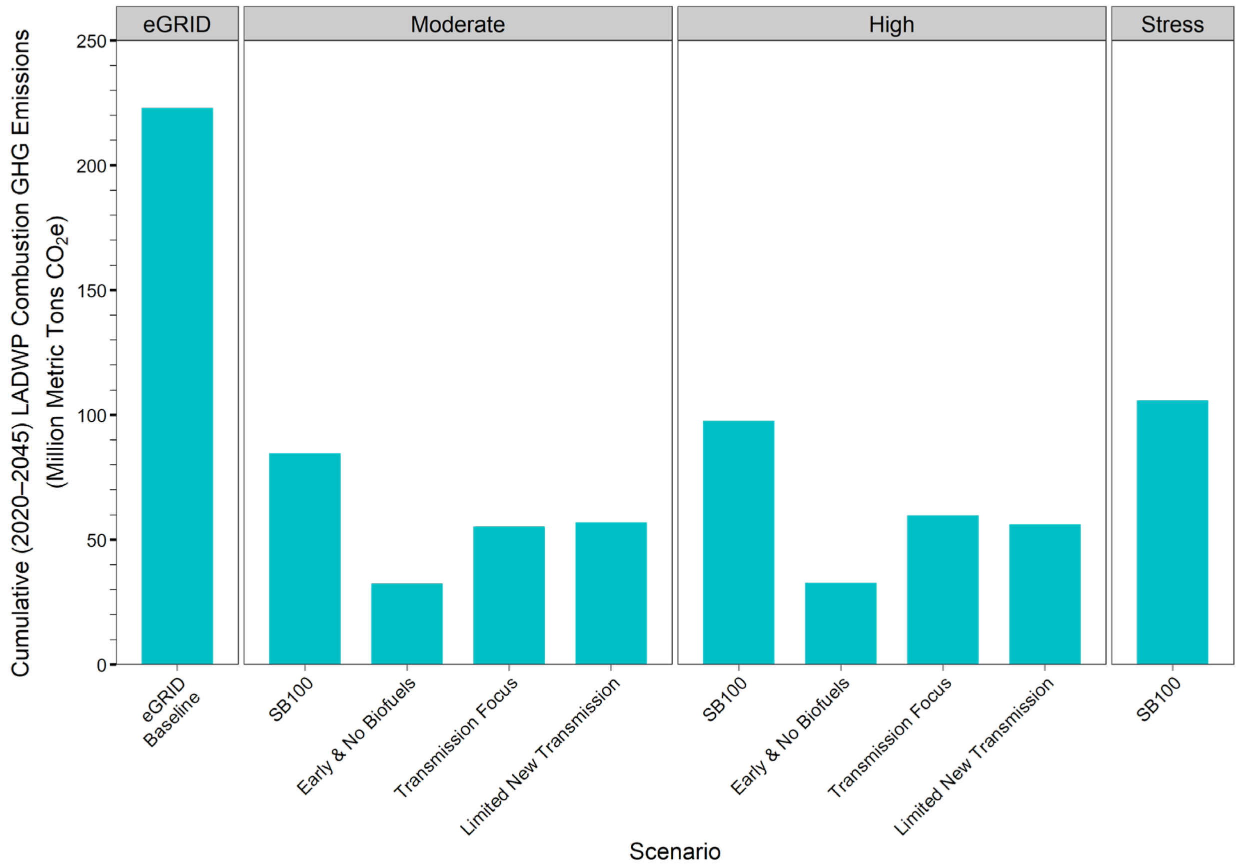


Figure 5. Comparison of cumulative (2020–2045) combustion GHG emissions for LA100 scenarios and the eGRID (2018) extrapolated baseline

Figure 6 shows combustion GHG emissions for each LA100 scenario, by technology type. Across all scenarios, GHG emissions from coal generation initially dominate at about 8 MMT CO_2/year, before quickly dropping off after 2025, leaving natural gas-fired plants to account for the remaining, if any, combustion emissions from 2030 onward. Coal accounts for between 35% (SB100 – Stress) and 65% (Early & No Biofuels – Moderate) of the cumulative (2020–2045) combustion emissions in each LA100 scenario, with natural gas technologies, mainly steam/combined cycle, accounting for the remaining fraction. Natural gas combustion emissions are generally below 3 MMT CO_2/year across the scenarios modeled until the year in which combustion technologies are phased out (2035 in the Early & No Biofuels set, 2045 in the Limited New Transmission and Transmission Focus sets). Cumulative combustion GHG emissions for 2020–2045 range from 32.4 MMT CO_2e in the Early & No Biofuels – Moderate scenario to 105 MMT CO_2e in the SB100 – Stress scenario. Combustion emission factors for existing fossil generators were calculated from eGRID data based upon reported CO_2 emissions divided by eGRID-reported fuel burn for 2018, the most recent year in which data are available (EPA 2020). See Appendix A, Table 11 for more details on the generator-specific combustion GHG emissions factors used in this study. It is important to note, however, that combustion is only one phase of the electricity generation life cycle; later in this chapter, we report GHG impacts for other life cycle phases.

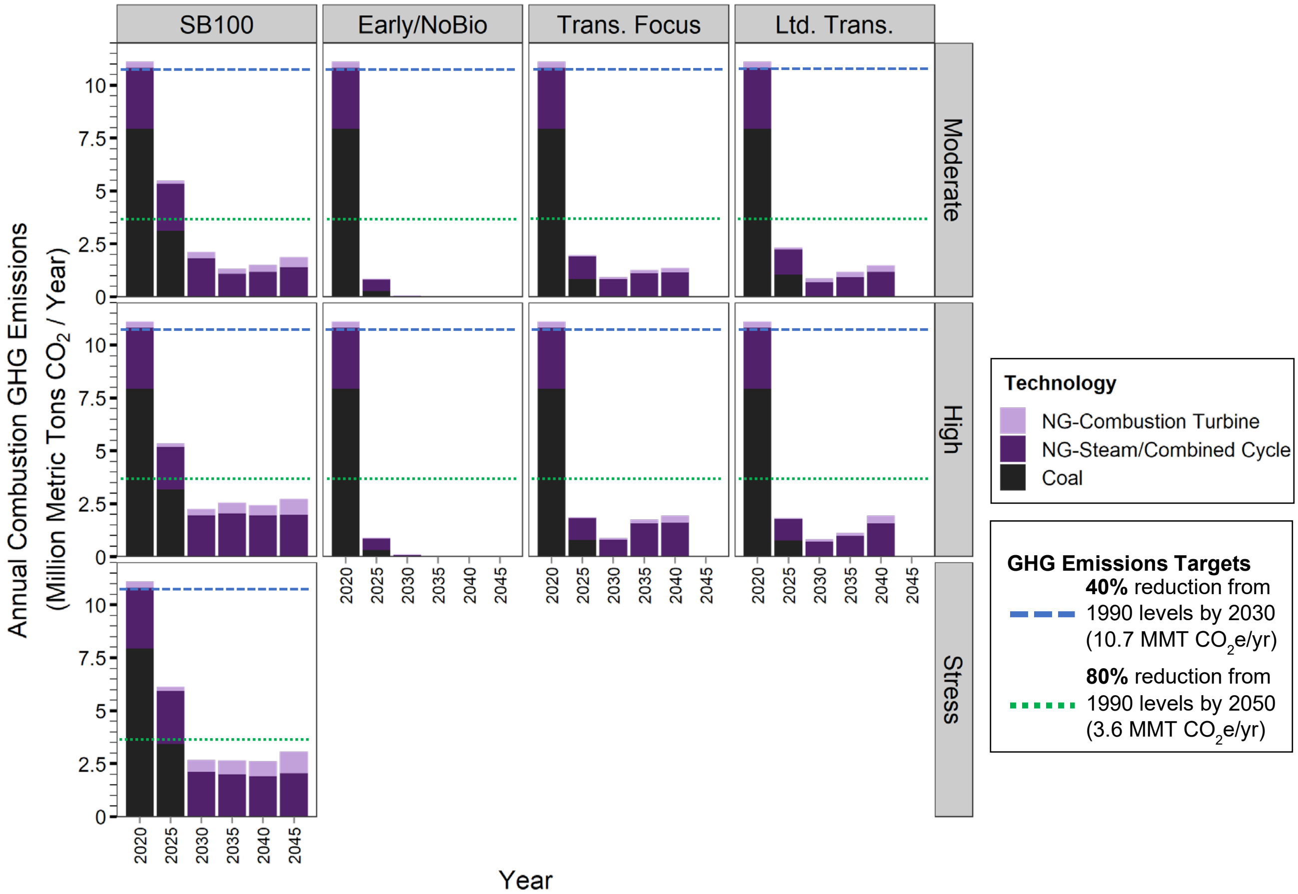


Figure 6. Combustion GHG emissions for each LA100 scenario, by year and technology type

Emissions for each timestep (stacked bar) shown in this figure are attributed to fossil generators operating for a single year (not the entire 5-year timestep). Blue and green dashed lines represent emissions levels at which LADWP would be contributing commensurately to statewide GHG emissions reductions targets of 40% by 2030 (SB32) and 80% by 2050 (EO S-3-05), respectively, relative to 1990 emissions levels.

In 2005, Executive Order (EO) S-3-05 set a target for California statewide GHG emissions 80% below 1990 levels by 2050, which is approximately 345 MMT CO_2e/year lower than the 1990 level. AB 32 (2006) established a California GHG reduction target of getting back to 1990 GHG emission levels by 2020, which was achieved in 2017. Executive Order B-30-15 (2015) and SB 32 (2016) established another intermediate California GHG reduction target of 40% below 1990 levels by 2030, or approximately 172 MMT CO_2e/year lower than 1990 level. Figure 6 also compares estimated annual combustion GHG emission levels in each LA100 scenario to those at which LADWP generation assets would need to operate to contribute commensurately to the specified targets. In all LA100 scenarios, LADWP's assets exceed commensurate contribution to the statewide 40% (blue dashed line) and 80% (green dashed line) GHG reduction targets for 2030 and 2050, respectively.

3.2 Life Cycle GHG Emission Results

Figure 7 shows the trajectory of annual life cycle GHG emissions over the study period (2020–2045). All LA100 scenarios show significantly lower annual life cycle GHG emissions in 2045 compared to 2020. The Early & No Biofuels – Moderate and Early & No Biofuels – High scenarios are both estimated to have the highest reduction of annual life cycle GHG emissions in 2045 relative to 2020 (95% and 93% lower, respectively). Importantly, the Early & No Biofuels scenarios do not have any *combustion* emissions from 2035 onward; all GHG emissions are associated with other life cycle stages (construction, decommissioning, and maintenance of the generator plants), as shown in the next section of this chapter (Section 3.3). Annual life cycle GHG emissions in the Early & No Biofuels set reach 0.6–0.9 MMT CO_2e/year in 2045, while the SB100 set is highest, at 2.9–4.6 MMT CO_2e/year in the same year. The Transmission Focus and Limited New Transmission scenarios fall in between Early & No Biofuels and SB100 and range from 1.4–1.7 MMT CO_2e/year by 2045. Also note that by 2035, all LA100 scenarios except SB100 – Stress show lower annual life cycle GHG emissions than the 2017 IRP scenario's estimated 4.3 MMT CO_2e/year.

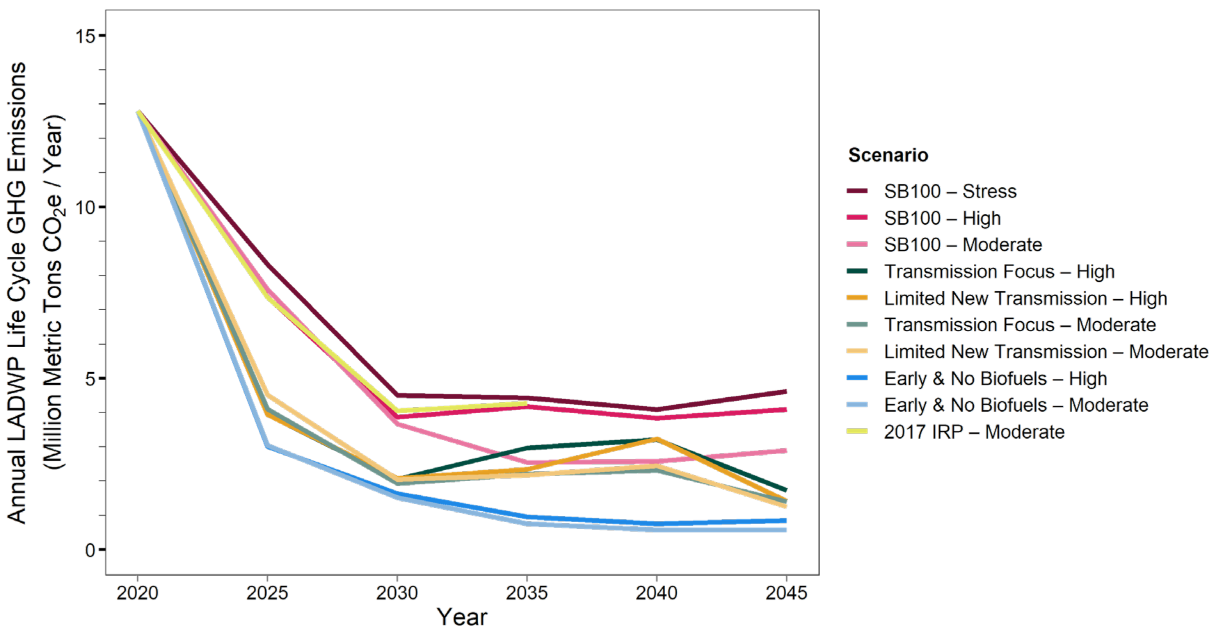
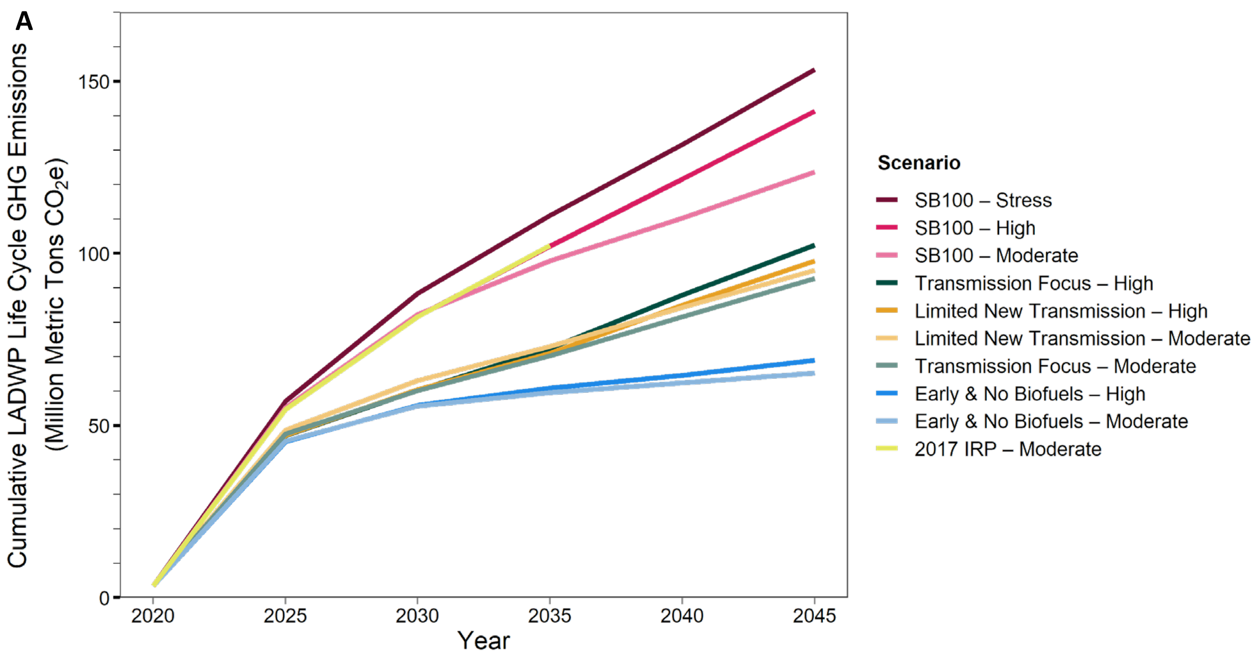


Figure 7. Comparison of annual life cycle GHG emissions for LA100 scenarios and the 2017 IRP scenario

Figure 8A depicts the aggregated life cycle GHG estimates for each LA100 scenario through 2045. We first compare the LA100 scenarios to the 2017 IRP which runs through 2035. With the exception of SB100 – Stress (9% higher), all LA100 scenarios are estimated to reduce cumulative (2020–2035) life cycle GHG emissions relative to the 2017 IRP. The greatest reductions are seen in the Early & No Biofuels scenarios, which exhibit estimated cumulative (2020–2035) GHG emission reductions of 41–43 MMT CO_2e, equivalent to 40%–42% lower relative to the 2017 IRP. The set of SB100 scenarios have estimated cumulative (2020–2035) GHG emissions ranging from 9 MMT CO_2e (9%) higher to 5 MMT CO_2e (4%) lower than those of the 2017 IRP.

For the full study period (2020–2045), the Early & No Biofuels set of scenarios has the lowest cumulative life cycle GHG emissions in the study period, at 65–69 MMT CO_2e, equivalent to about 49%–53% of the corresponding SB100 scenarios. Cumulative (2020–2045) life cycle GHG emissions from the Moderate load and High load projections of the Transmission Focus and Limited New Transmission scenarios are similar and fall in between the sets of SB100 and Early & No Biofuels scenarios, at between 93 and 102 MMT CO_2e.

Figure 8B shows how each LA100 scenario's cumulative (2020–2045) life cycle GHG emissions are composed of combustion emissions (blue bars) and all other life cycle phases (red bars). Combustion accounts for between 48% (Early & No Biofuels – High) and 69% (SB100 – High) of the cumulative (2020–2045) life cycle GHG emissions across the LA100 scenarios. The other life cycle phases include one-time upstream, ongoing non-combustion, and one-time downstream. These other phases account for between 31% (SB100 – High) and 52% (Early & No Biofuels – High) of the cumulative (2020–2045) life cycle GHG emissions across the LA100 scenarios.



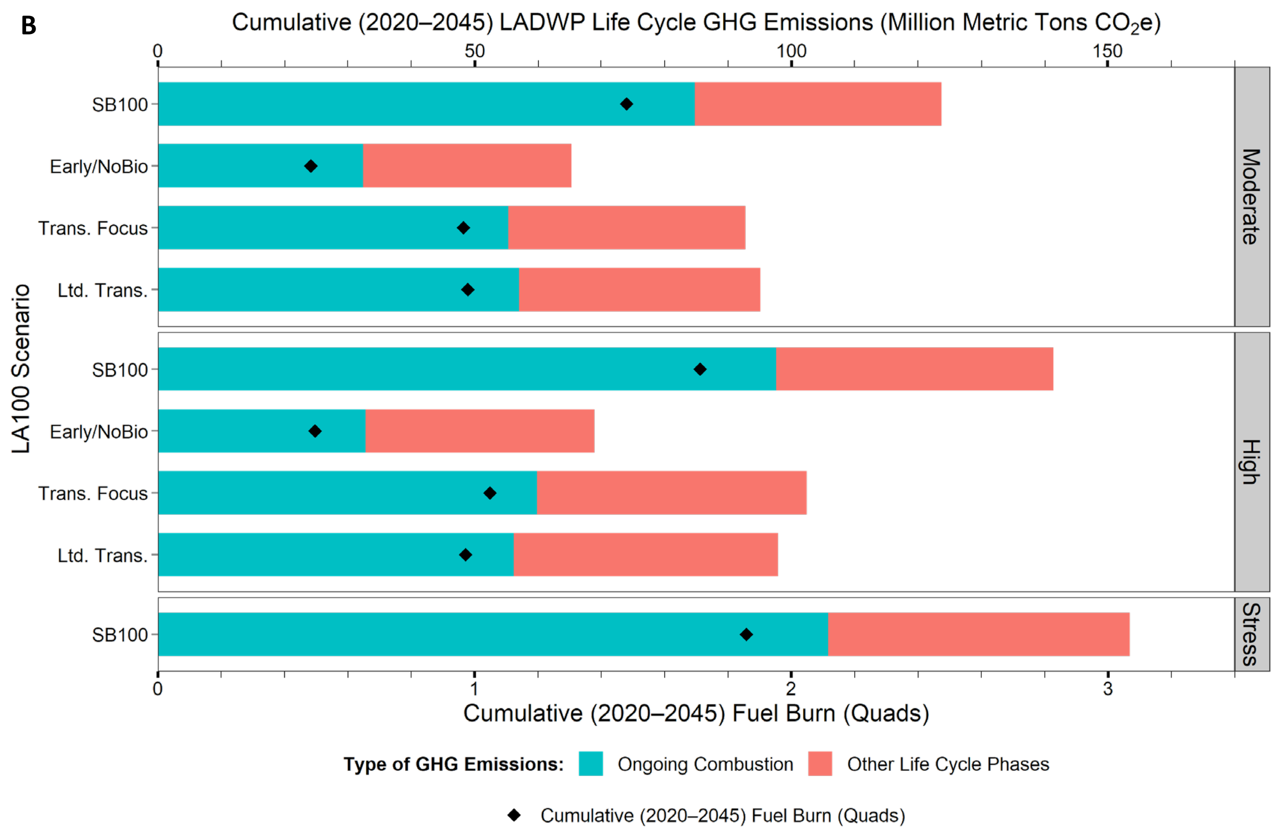


Figure 8. Cumulative life cycle GHG emissions for each LA100 scenario through 2045

A. Time-series trajectories showing cumulative life cycle GHG emissions from 2020–2045 for LA100 scenarios compared to the 2017 IRP scenario, which ends in 2035.
B. Cumulative 2020–2045 life cycle GHG emissions disaggregated into combustion phase and all other life cycle phases

Cumulative fuel burn in quadrillion BTUs (Quads) is provided for reference to highlight variations in combustion levels. Other life cycle phases include one-time upstream (construction), ongoing non-combustion, and one-time downstream (decommissioning). Note that B does not include the 2017 IRP scenario, which ends in 2035.

Figure 9A compares annual life cycle GHG emissions in 2035 between the LA100 scenarios and the 2017 IRP (which runs through 2035). All of the LA100 scenarios, with the exception of SB100 – Stress, exhibit lower annual life cycle GHG emissions relative to the 2017 IRP in 2035. These comparisons to the 2017 IRP scenario range from 0.16 MMT CO_2e/year (4%) higher in the SB100 – Stress scenario to 3.5 MMT CO_2e/year (82%) lower in the Early & No Biofuels – Moderate scenario. Figure 9B compares annual life cycle GHG emissions in 2045 between the LA100 scenarios. The Early & No Biofuels set of scenarios has the lowest annual life cycle GHG emissions in this year, at 0.6–0.9 MMT CO_2e/year. The Early & No Biofuels scenarios' annual (2045) life cycle GHG emissions are approximately 80% lower than those of the corresponding SB100 scenarios. The annual (2045) GHG emissions attributed to the life cycle phases outside of combustion account for 100% of annual GHG emissions in all LA100 scenarios except the SB100 set, where they account for 64%–67%.

The remaining figures in the results section of this chapter capture the GHG impact for each life cycle phase in greater detail.

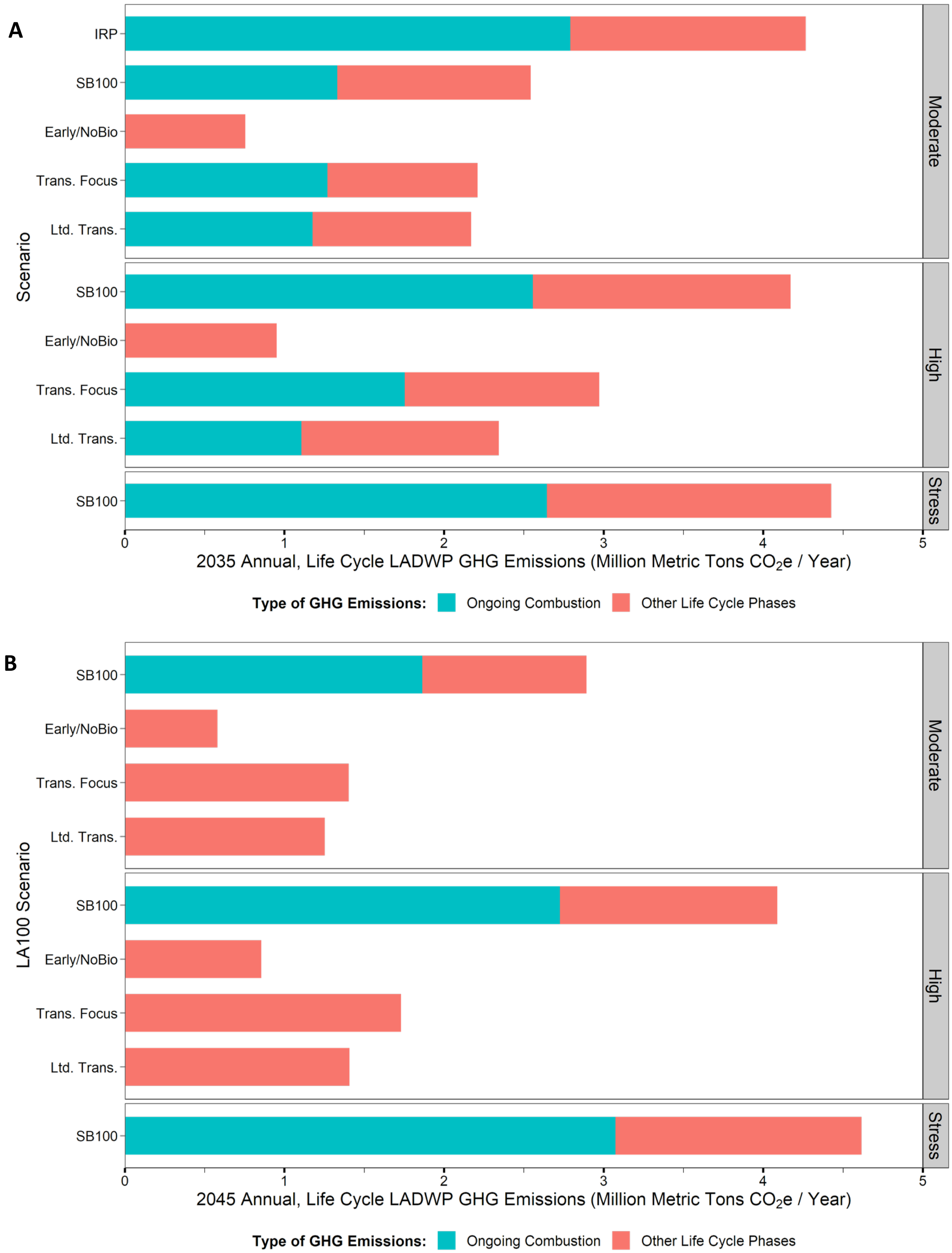


Figure 9. Comparison of annual life cycle GHG emissions in 2035 and 2045

A. Comparison of 2035 annual life cycle GHG emissions to 2017 IRP case.
B. Comparison of 2045 annual life cycle GHG emissions between LA100 scenarios

Other life cycle phases include one-time upstream (construction), ongoing non-combustion, and one-time downstream (decommissioning).

3.3 Upstream Phase GHG Emission Results

The first phase in the electricity generation life cycle is one-time upstream emissions. Emissions in this phase include those associated with the extraction and processing of primary materials used in manufacturing and assembly of the generator components as well as plant construction; fuel use and associated fuel-cycle emissions for fuels used in these activities is also included. Technology-specific emissions factors for the upstream phase, in units of grams of CO_2 per unit of capacity, are listed in Appendix A, Table 10.

Figure 10 illustrates the upstream GHG emissions over time across the LA100 scenarios. Note that because production cost modeling is run only in 5-year time steps, we accumulate all capacity additions with the 5-year period and distribute the associated one-time GHG emissions evenly over the 5-year timestep to obtain annualized estimates. Cumulative upstream (2020–2045) GHG emissions range from 18 MMT CO_2e (SB100 – Moderate) to 26 MMT CO_2e (Transmission Focus – High). For all scenarios and across most modeled years, construction of solar generating capacity (concentrating solar power, customer photovoltaic, utility photovoltaic, and utility photovoltaic plus battery) accounts for a majority of the upstream emissions. Note that these results do not include an estimated additional upstream impact (identical across all scenarios) of less than 0.7 MMT CO_2e in the 2040–2045 timeframe from utility battery storage turnover after battery capacity added in the 2020–2025 timeframe reaches its end of life and is replaced.[13]

The balance of upstream emissions are predominantly from wind capacity, as well as lesser amounts from geothermal and battery storage capacity additions. Construction of solar capacity accounts for between 12 MMT CO_2e (SB100 – Moderate) and 18 MMT CO_2e (Transmission Focus – High) of cumulative (2020–2045) upstream emissions on an absolute basis, or between 61% (Early & No Biofuels – High) and 70% (Limited New Transmission – Moderate) of cumulative (2020–2045) upstream GHG emissions on a percentage basis.

A consistent trend across the LA100 scenarios is that upstream solar emissions are highest in the earlier model periods (2020–2030), reflecting the rapid expansion of solar capacity in the early years. In contrast, the steadier accumulation of wind capacity is reflected in the consistent level of upstream emissions attributed to that technology across scenario timesteps (approximately 0.1–0.4 MMT CO_2e/year). Construction of wind capacity accounts for between 3.4 MMT CO_2e (Early & No Biofuels – Moderate) and 5.8 MMT CO_2e (Limited New Transmission – High) of cumulative (2020–2045) upstream GHG emissions on an absolute basis, or between 15% (Early & No Biofuels – Moderate) and 23% (SB100 – High) of cumulative (2020–2045) upstream GHG

[13] This upper bound on GHG emissions from battery turnover is established using the entire utility battery system emissions factor, which includes the balance of system in addition to the battery itself. Given that the balance of system is assumed to remain in place during a battery replacement and the GHG emissions factor for the battery component of this factor was not isolated as part of this analysis, a more precise estimate of GHG emissions associated with battery turnover is not reported.

emissions on a percentage basis. Note that coal, nuclear, natural gas combustion-turbine (NG-CT), hydropower, and offshore wind technologies do not appear in this table because capacity of these technologies is not added in any scenarios.[14] Despite the absence of NG-CT upstream emissions, the related H_2–Combustion Turbine technology is assumed to have upstream GHG emissions equivalent (per unit of capacity) to those of NG–CT technology. Another caveat for the upstream results is that GHG emissions associated with transmission infrastructure construction are outside the scope of, and therefore excluded from, this analysis.

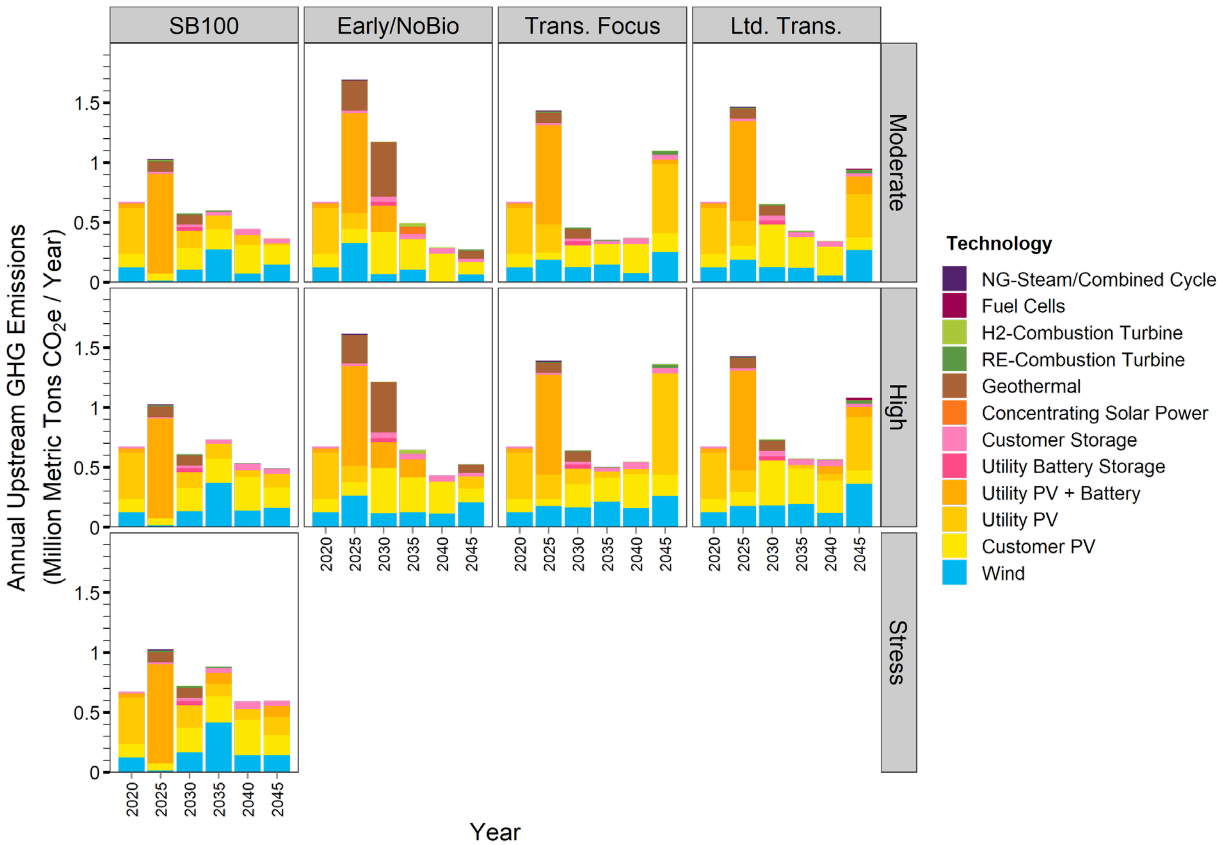


Figure 10. Upstream GHG emissions for each LA100 scenario, by year and technology type

Emissions shown in this figure are on an annual basis and are calculated as one fifth of the emissions attributed to capacity additions over the 5-year interval represented by each timestep year.

3.4 Ongoing Non-Combustion Phase GHG Emission Results

Figure 11 illustrates the GHG emissions from the ongoing non-combustion phase. Emissions in this phase result from plant O&M and from resource (fuel) extraction (if applicable); they are a function of each generator's annual generation, not capacity. Cumulative (2020–2045) non-combustion GHG emissions range from 9.7 MMT CO_2e (Early & No Biofuels – Moderate) to 25 MMT CO_2e (SB100 – Stress). Across the LA100 scenarios, a few consistent trends are observed

[14] CAES does have a modest capacity addition but does not appear in these results or factor into the overall GHG analysis presented herein. We could not find an emission factor for upstream construction but assume it is small.

in the non-combustion emissions. The first is that when fossil fuels are used, their fuel-cycle emissions dominate non-combustion GHG emissions. NG-Steam/Combined cycle (NG-CC) technology accounts for the majority of cumulative non-combustion emissions in each scenario; NG-CC percentage of cumulative (2020–2045) non-combustion emissions range from 34% (Early & No Biofuels – High) to 70% (SB100 – High). Aside from NG-CC, the other main contributors to non-combustion emissions are coal, PV (including utility and customer PV), nuclear, geothermal, and pumped hydroelectric storage (PHS).

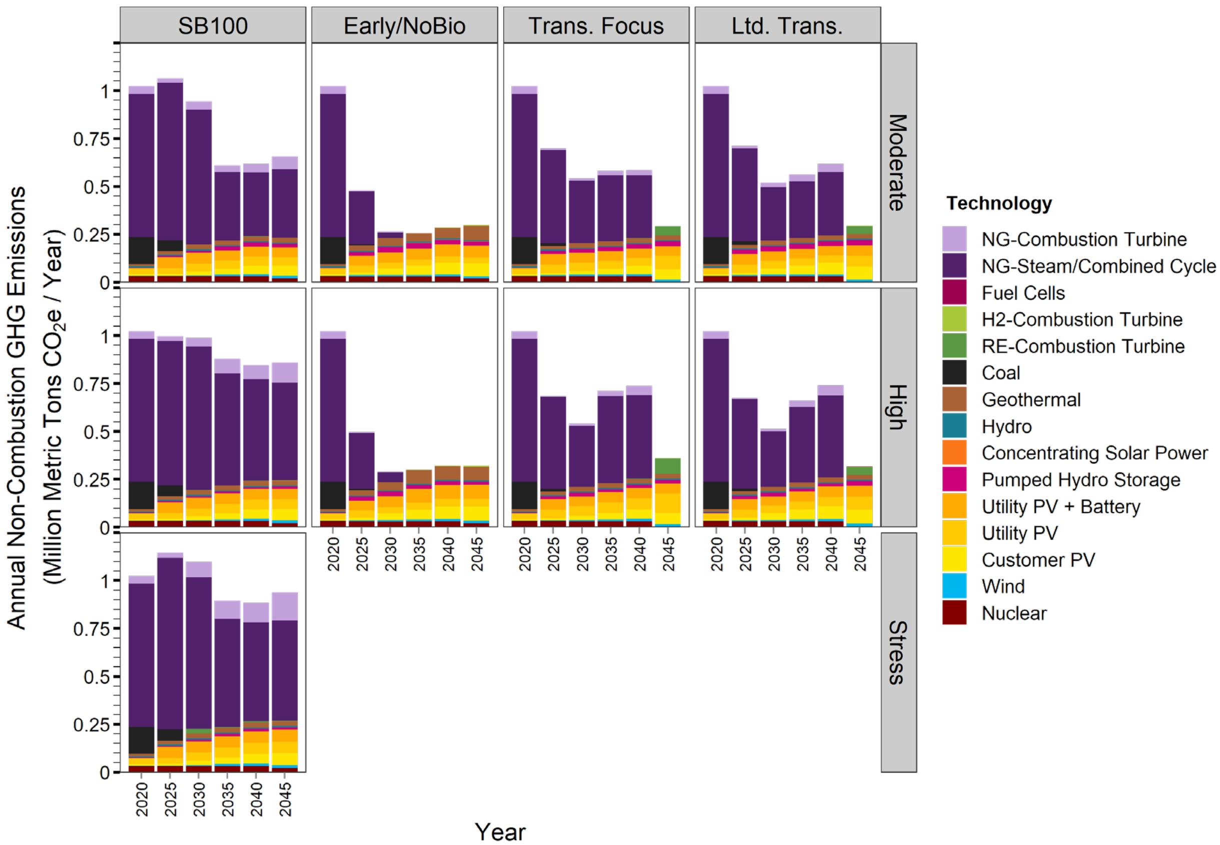


Figure 11. Ongoing, non-combustion GHG emissions for each LA100 scenario, by year and technology type

Emissions for each timestep (stacked bar) shown in this figure are attributed to generators operating for a single year (not the entire 5-year timestep).

In most LA100 scenarios, non-combustion emissions are generally highest in the earlier solve years (2020 and 2025) and decrease substantially by the end of the study period (with the exception of the SB100 scenario set). This is due to the use of fossil fuels in those earlier years. In the Limited New Transmission and Transmission Focus scenario sets, non-combustion emissions drop to a local minimum in the 2030 period before increasing up to 2040 as more solar and storage technology is operated in conjunction with natural gas technologies; non-combustion emissions drop off significantly in the final timestep (2045) of these scenarios once the natural gas technology is retired. In the Early & No Biofuels set of scenarios, non-combustion emissions drop off much earlier once natural gas technology is retired by the 2035 period.

3.5 Downstream Phase GHG Emission Results

The downstream (decommissioning) phase is the final phase of a generator's life cycle GHG emissions and also contributes the least of all phases to total life cycle GHG emissions. As shown in Figure 12, downstream GHG emissions are modest and exhibit similar patterns across all of the LA100 scenarios, with some minor differences. Each scenario has the highest downstream emissions occurring in the first two timesteps with coal plant retirement and then in the final timestep with the retirement of nuclear and PV capacity. The only noticeable difference across the LA100 scenarios' downstream GHG emissions pertains to the retirement of natural gas-fired generation capacity, which occurs soonest in the Early & No Biofuels set (retired in 2035 timestep), occurs later in the Limited New Transmission and Transmission Focus sets (retired in 2045 timestep), and does not occur in the SB100 scenarios. Cumulative downstream (2020–2045) GHG emissions range from 0.15 MMT CO_2e (SB100 – High) to 0.17 MMT CO_2e (Early & No Biofuels – High). Note that these results do not include an estimated additional downstream impact of less than 0.1 MMT CO_2e (identical across all scenarios) in the 2040–2045 timeframe from utility battery storage turnover after battery capacity added in the 2020–2025 timeframe reaches its end of life and is replaced.[15]

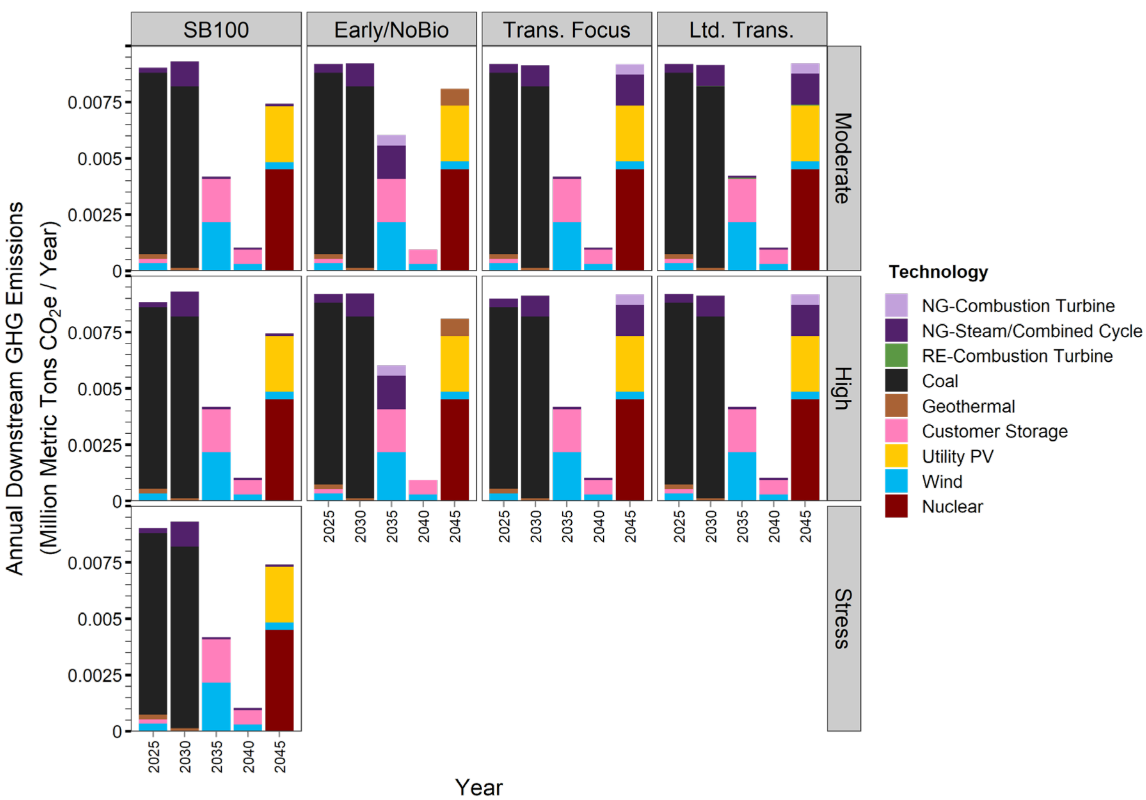


Figure 12. Downstream GHG emissions for each LA100 scenario, by year and technology type

Emissions shown in this figure are on an annual basis and are calculated as one fifth of the emissions attributed to cumulative capacity retirements over the 5-year interval represented by each timestep year.

[15] See Footnote 13.

4 Non-Power Sector Results

This section is organized into the two main non-power sectors that were considered: buildings and vehicles. The building sector results are reported for residential and commercial buildings, and the vehicle sector results are reported for light-duty vehicles (cars and light trucks) and buses (urban and school). The LA100 projections included in this analysis are listed below:

- Buildings – Load Projections
  - Moderate
  - High
  - Stress
- Vehicles – Electrification Adoption Projections
  - Moderate
  - High

4.1 Buildings

GHG emissions in the building sector are attributed to the combustion of natural gas for building heating, appliances, and other needs. Life cycle GHG emissions are a combination of both combustion and fuel-cycle (extraction, processing, and transportation of fuels) emissions from the natural gas. A summary of the emissions factors per unit of natural gas consumption that were used in the calculations for the building sector is given in Appendix A. Table 2 describes the characteristics of each assumed load projection in the buildings sector.

Table 2. LA100 Load Projections

Load Projection	**Moderate**	**High**	**Stress**
Description	The Moderate load projection assumes easy, low-hanging-fruit electrification and moderate (above-code) improvements to energy efficiency and demand response. Significant change, but short of the Mayor's Office's Green New Deal 2019 pLAn goals; see hplan.lamayor.org.	The High projection is designed to match most of the electrification and energy efficiency goals set forth in the 2019 pLAn and includes 80% light-duty vehicle electrification by 2045 and significant demand response potential. Very high electrification results in significantly more demand, even with high levels of energy efficiency.	High electrification combined with low energy-efficiency improvements and demand response to create worst-case load conditions.

As shown in Figure 13, the cumulative amount of GHG emissions are estimated to be lower in the High and Stress load projections than in the Moderate load projection due to electrification. The high amount of electrification assumed in the High and Stress load projections means that fewer building appliances and HVAC systems rely on natural gas for the buildings' energy needs, especially in the later modeled years. The Stress load projection, in which energy efficiency remains low compared to Moderate and High projections, shows slightly higher GHG emissions than those of the High load projection. Cumulative, combined life cycle GHG emissions for residential and commercial buildings for the period from 2020 to 2045 are approximately 123 MMT CO_2e in the Moderate load projection, which is equivalent to about 14 million average U.S. homes' energy use in one year.[16] Totals for the other load projections are 74 MMT CO_2e (equivalent to 8.5 million homes' annual energy use) for the High load projection (40% lower than Moderate) and 81 MMT CO_2e (equivalent to 9.3 million homes' annual energy use) for the Stress load projection (34% lower than Moderate; 9% higher than High). As is observed in results across the buildings GHG analysis, the relative GHG impacts for the residential and commercial sectors are quite similar when comparing between load projections.

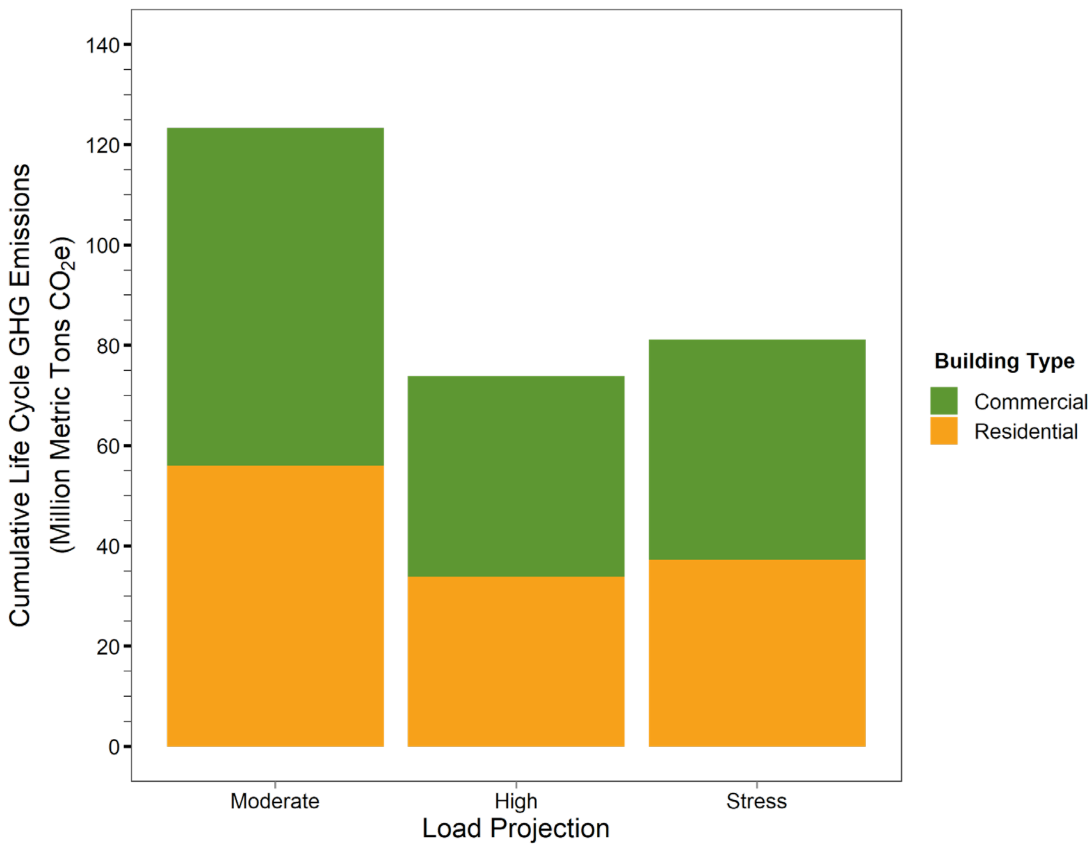


Figure 13. Cumulative (2020–2045) life cycle GHG emissions for residential and commercial buildings, by load projection and building type

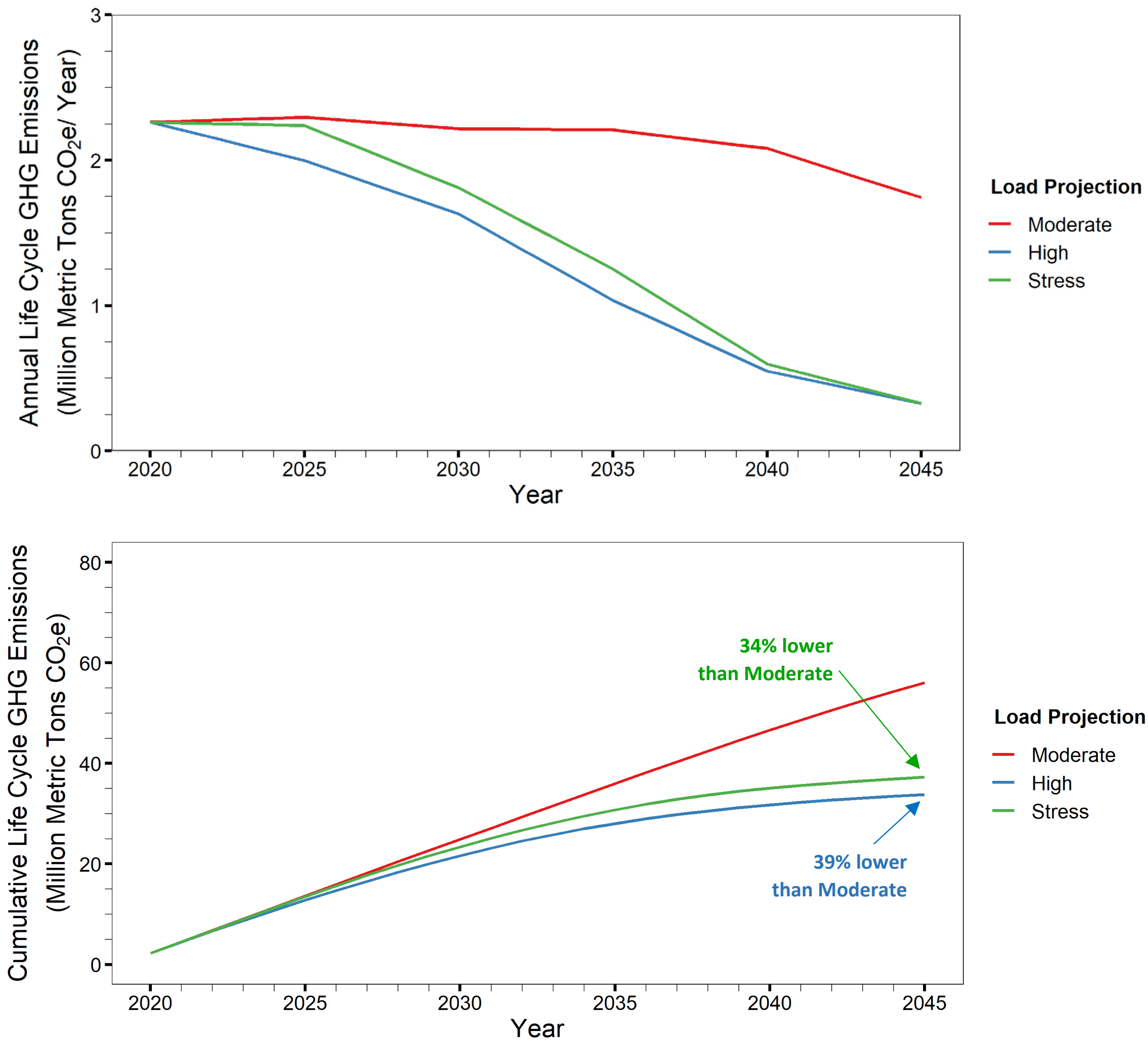
See Appendix D, Table 26 for numerical results.

[16] See Footnote 12.

4.1.1 Residential

Estimated annual GHG emissions in the residential building sector are presented in the top portion of Figure 14. It is evident that the High and Stress projections follow a similar trajectory in decreasing annual GHG emissions from approximately 2.3 MMT CO_2e/year in 2020 to 0.34 MMT CO_2e/year and 0.37 MMT CO_2e/year by 2045, respectively, implying a reduction of about 86%. Annual natural gas use in the residential buildings in the High and Stress projections both fall from 296 million therms/year in 2020 to about 43 million therms/year in 2045, a reduction of also about 86%. The Moderate load projection exhibits a smaller reduction in annual GHG emissions, from 2.3 MMT CO_2e/year to 1.7 MMT CO_2e/year, a reduction of about 23%. Annual natural gas use in the Moderate projection falls from 296 million therms/year in 2020 to 228 million therms/year in 2045, a reduction of also about 23%. The High projection sees steady reductions beginning in the first modeled year (2020), whereas the steadier reduction in annual GHG emissions begins in 2025 in the Stress projection and not until 2035 in the Moderate projection.

The bottom portion of Figure 14 reports cumulative residential building life cycle GHG emissions over the full model period (2020–2045). The Moderate projection exhibits the highest total, at approximately 56 MMT CO_2e by 2045, or approximately the amount of energy used by 6.5 million average U.S. homes in one year. The High and Stress projections reach 34 MMT CO_2e (3.9 million homes' annual energy use) and 37 MMT CO_2e (4.3 million homes' energy use) by 2045, respectively,



which are 39% lower and 34% lower than those of the Moderate load projection, respectively.

Figure 14. Annual (top) and cumulative (bottom) life cycle GHG emissions for residential buildings, by year and load projection

See Appendix D, Table 27 for numerical results.

Figure 15 summarizes the cumulative (2020–2045) emissions in each load projection and disaggregates them by life cycle phase. Blue bars represent emissions from combustion of fossil fuel (natural gas) only, while the red bars indicate the additional GHG emissions attributed to the fuel cycle (extraction, processing, and transportation) of the fossil fuel. Across all three load projections, combustion emissions account for approximately 78% of the cumulative life cycle GHG emissions from the residential building sector, with the remaining 22% attributed to the fuel-cycle phase.

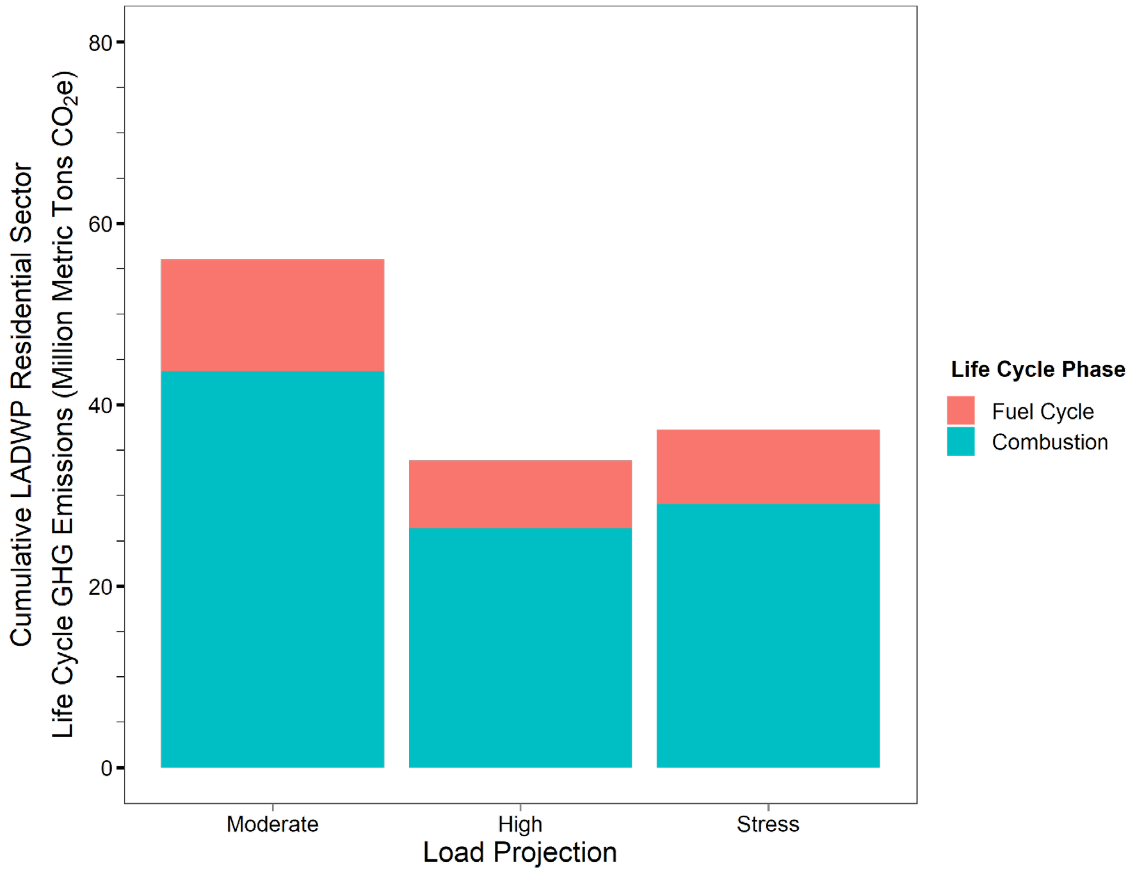


Figure 15. Cumulative (2020–2045) GHG emissions for residential buildings, by life cycle phase for each load projection

See Appendix D, Table 29 for numerical results

4.1.2 Commercial

Estimated annual GHG emissions in the commercial building sector are presented in the top portion of Figure 16. It is evident that the High and Stress projections follow a similar trajectory in decreasing annual GHG emissions from approximately 2.6 MMT CO_2e/year in 2020 to 0.3 MMT CO_2e/year by 2045, a reduction of about 87%. Annual natural gas use in the commercial buildings in the High and Stress projections both fall from 346 million therms in 2020 to about 45 million therms in 2045, a reduction of about 87%. The Moderate projection exhibits a smaller reduction in annual GHG emissions, from 2.6 MMT CO_2e/year to 2.2 MMT CO_2e/year, a reduction of about 15%. Annual natural gas use in the Moderate projection falls from 346 million therms in 2020 to 295 million therms in 2045, a reduction of also about 15%. The GHG emissions fraction is slightly lower than the corresponding natural gas combustion reduction due to a reduction in energy. As with the residential sector, the commercial High projection sees steady reductions beginning in the first modeled year (2020), whereas the steadier reduction in annual GHG emissions begins in 2025 in the Stress projection and not until 2035 in the Moderate projection.

The bottom portion of Figure 16 reports cumulative commercial building life cycle GHG emissions over the full model period (2020–2045). The Moderate projection exhibits the highest total, at approximately 67 MMT CO_2e by 2045, or approximately the amount of energy used by 7.7 million average U.S. homes in one year. The High and Stress projections reach 40 MMT CO_2e (4.6 million homes' annual energy use) and 44 MMT CO_2e (5.1 million homes' annual energy use) by 2045, respectively, which are 41% lower and 35% lower than those of the Moderate projection, respectively.

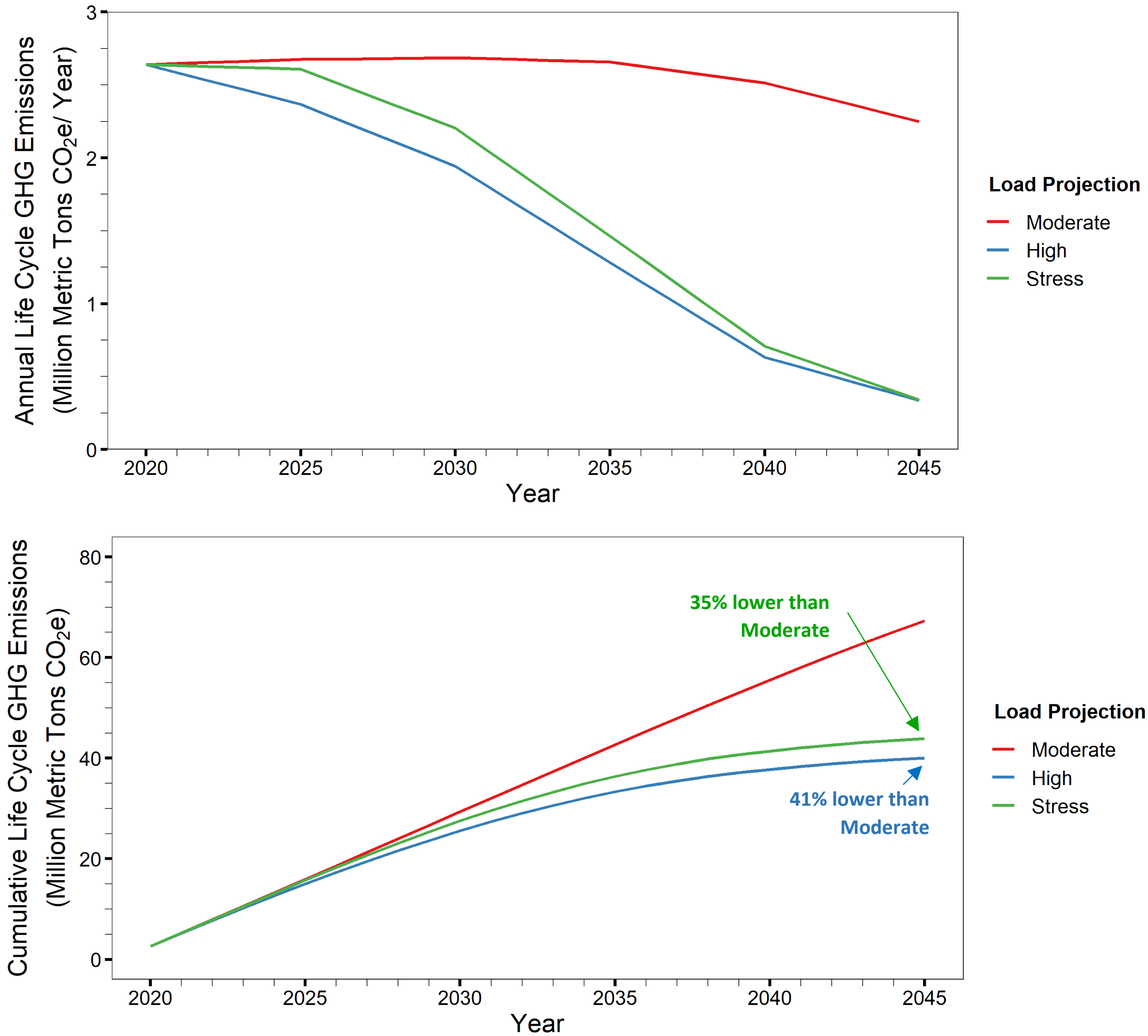


Figure 16. Annual (top) and cumulative (bottom) life cycle GHG emissions for commercial buildings, by year and load projection

See Appendix D, Table 28 for numerical results.

Figure 17 summarizes the cumulative (2020–2045) emissions in each load projection and disaggregates them by life cycle phase. Blue bars represent emissions from combustion of fossil fuel (natural gas) only, while the red bars indicate the additional GHG emissions attributed to the fuel cycle (extraction, processing, and transportation) of the fossil fuel. Across all three load projections, combustion emissions account for approximately 78% of the cumulative life cycle GHG emissions from the commercial building sector, with the remaining 22% attributed to the fuel cycle phase.

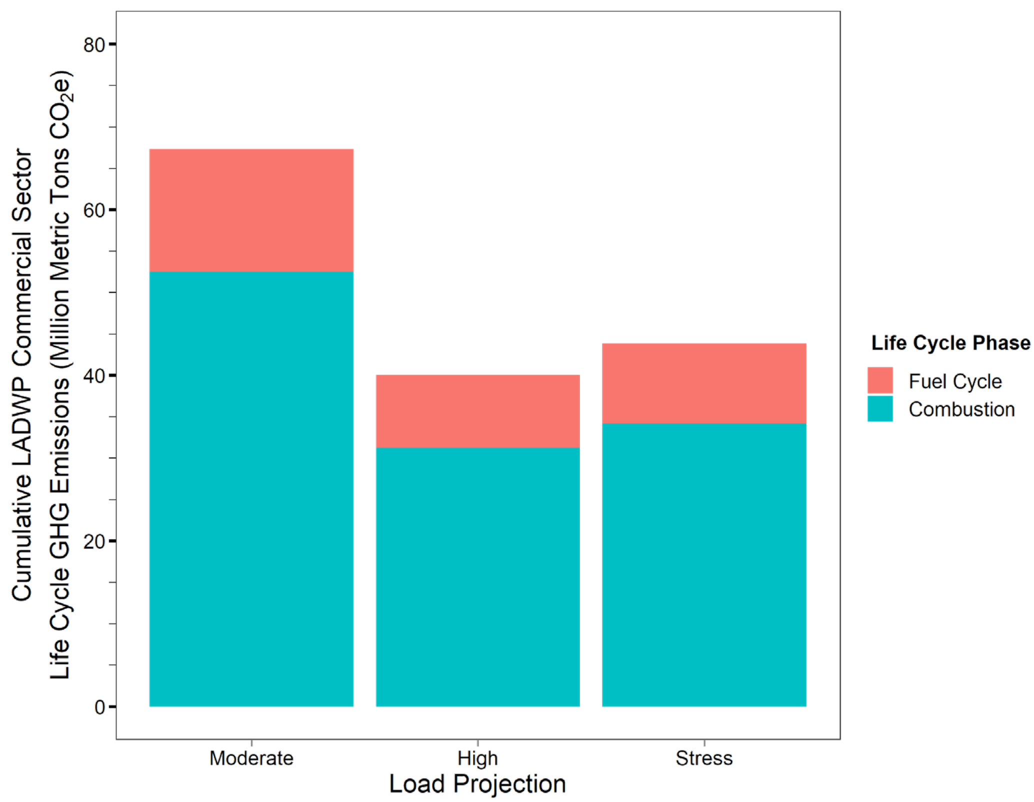


Figure 17. Cumulative (2020–2045) GHG emissions for commercial buildings, by life cycle phase, for each load projection

See Appendix D, Table 29 for numerical results.

4.2 Vehicles

Light-duty vehicle and bus fleet GHG emissions are primarily generated by the combustion of fossil transportation fuels, including gasoline, diesel, compressed natural gas, and propane. The emissions assumptions for each of these fuels is described in detail in Appendix B. A summary of the emissions factors used in these calculations for the vehicle sector is given in Appendix B. The EV adoption projections assumed in the vehicle sector are listed below:

- **Moderate** projection – EV adoption is based on the 2017 SLTRP ‘high case’ EV adoption. This projection exceeds the California Zero Emission Vehicle (ZEV) mandate in 2025 and meets the 2030 goal. Thirty percent of vehicle stock is electrified by 2045.

- **High** projection – EV adoption based on the 2017 SLTRP 'high case' until 2025, and then a more aggressive EV adoption from 2026 based on the NREL Electrification Futures Study (EFS) study. Eighty percent of vehicle stock is electrified by 2045.

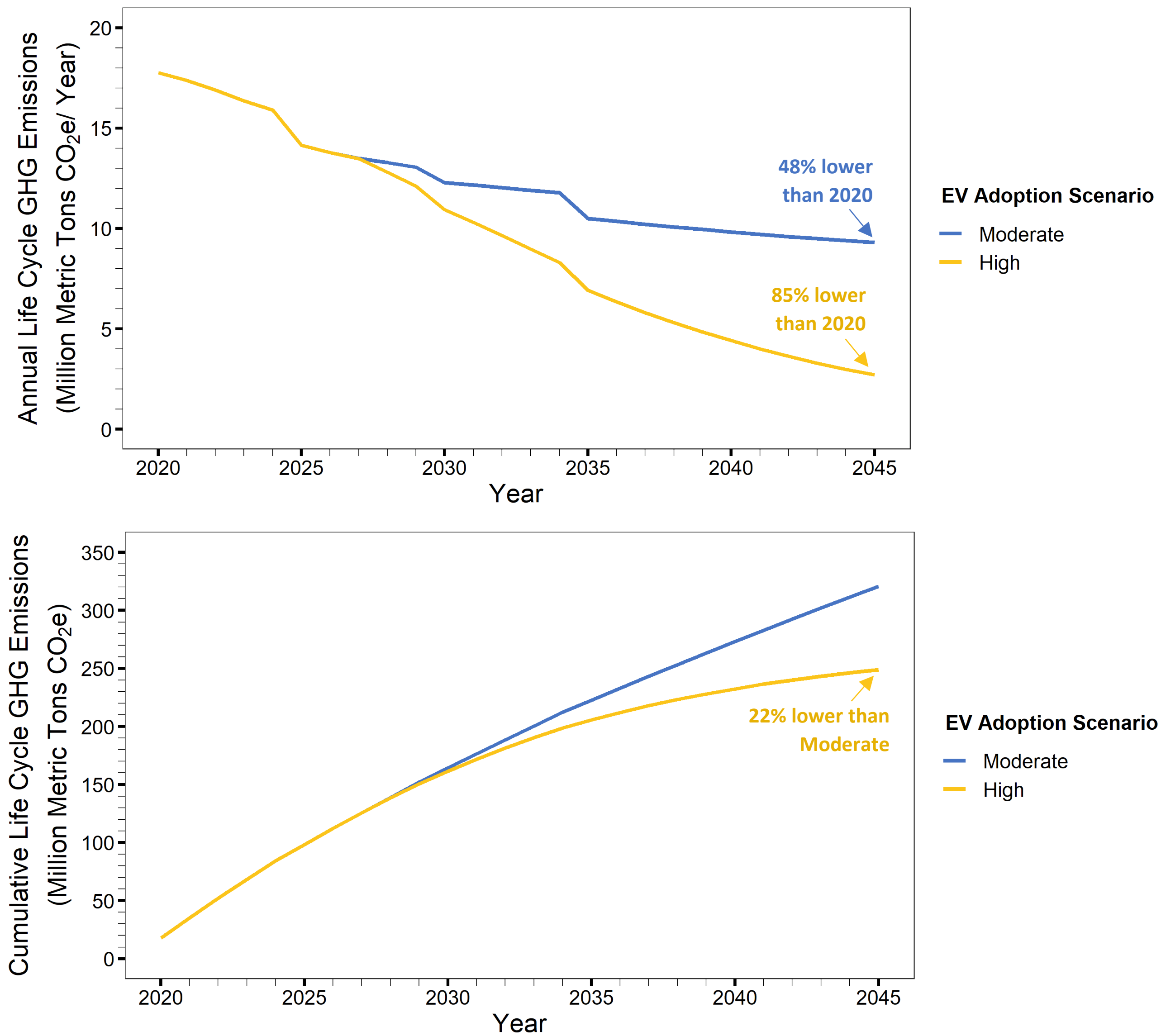


Figure 18. Annual (top) and cumulative (bottom) life cycle GHG emissions for vehicles (light-duty and buses), by year and EV adoption projection

See Appendix E, Table 30 for numerical results.

As will be shown below, the vast majority of vehicle GHG emissions considered in LA100 are from the more than three million passenger cars and light-duty trucks assumed to be included in the LA100 analysis area, with essentially negligible contribution from the few thousand metro and school buses also included in the analysis. In all projections, the bus fleets are assumed to be entirely electric by 2030, with no direct GHG emissions attributed to those fleets after that year.

One other point of note is that this analysis only covers light-duty vehicles and buses; it does not cover medium- or heavy-duty trucks.

Estimated annual GHG emissions in the vehicle sector are presented in the top portion of Figure 18. The Moderate and High EV adoption projections both exhibit a reduction in annual life cycle GHG emissions in 2045 relative to 2020. Annual life cycle GHG emissions for the Moderate and High adoption projections are estimated to be 9.3 MMT CO_2e/year and 2.7 MMT CO_2e/year in 2045, respectively, which correspond to reductions of 48% and 85% compared to 2020.

The bottom portion of Figure 18 reports cumulative vehicle life cycle GHG emissions over the full model period (2020–2045). The High projection exhibits the lower total, at approximately 250 MMT CO_2e by 2045 (equivalent to consuming 28 billion gallons of gasoline, or about 72 days of U.S. nationwide gasoline consumption at 2019 rates[17]). The Moderate totals 320 MMT CO_2e by 2045, which is equivalent to 92 days of 2019 U.S. gasoline consumption. Compared to 2020, the High and Moderate projections in 2045 exhibit annual life cycle GHG emissions that are lower by 30% and 9.5%, respectively.

Another way of examining the cumulative life cycle GHG impacts is presented in Figure 19, which summarizes the GHG contributions from the two life cycle phases considered in this analysis: fossil fuel combustion and fuel cycle. Blue bars represent emissions from combustion of fossil fuels, while the red bars indicate the additional GHG emissions attributed to the fuel cycle (extraction, processing, and transportation). Across both EV adoption projections, combustion emissions account for approximately 69% of the cumulative life cycle GHG emissions from the vehicle sector, with the remaining 31% attributed to the fuel-cycle phase.

[17] "Frequently Asked Questions (FAQS): How Much Gasoline Does the United States Consume?" EIA, https://www.eia.gov/tools/faqs/faq.php?id=23.

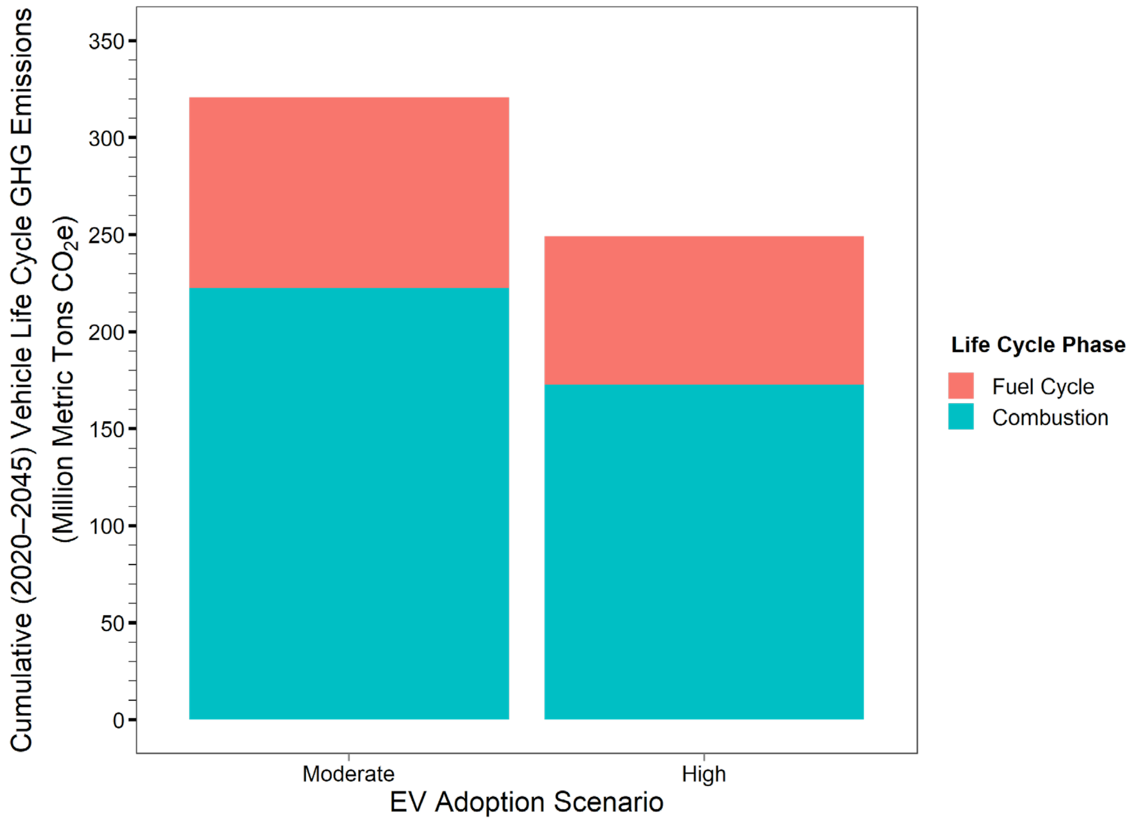


Figure 19. Cumulative (2020–2045) GHG emissions for vehicles (light-duty and buses), by life cycle phase, for each EV adoption projection

See Appendix E, Table 31 for numerical results.

Figure 20 presents annual life cycle GHG emissions for each adoption projection disaggregated by the type of vehicle to which they are attributed. It is immediately evident that passenger cars and light-duty trucks account for almost all the GHG emissions in the study period, with the two bus fleets contributing negligible annual emissions. In 2020, passenger cars account for 58% of annual GHG emissions while the two types of light-duty trucks combine to account for 41% and the two bus fleets account for 1%. By 2045, in the High projection, passenger cars account for 54% of annual life cycle GHG emissions, with light-duty trucks accounting for the remaining 46%. Buses account for 0% of annual transportation sector emissions after 2030 due to the assumed 100% electrification by that year.[18]

[18] For GHG emissions impacts from medium- and heavy-duty vehicles, see Chapter 9, Appendix A.

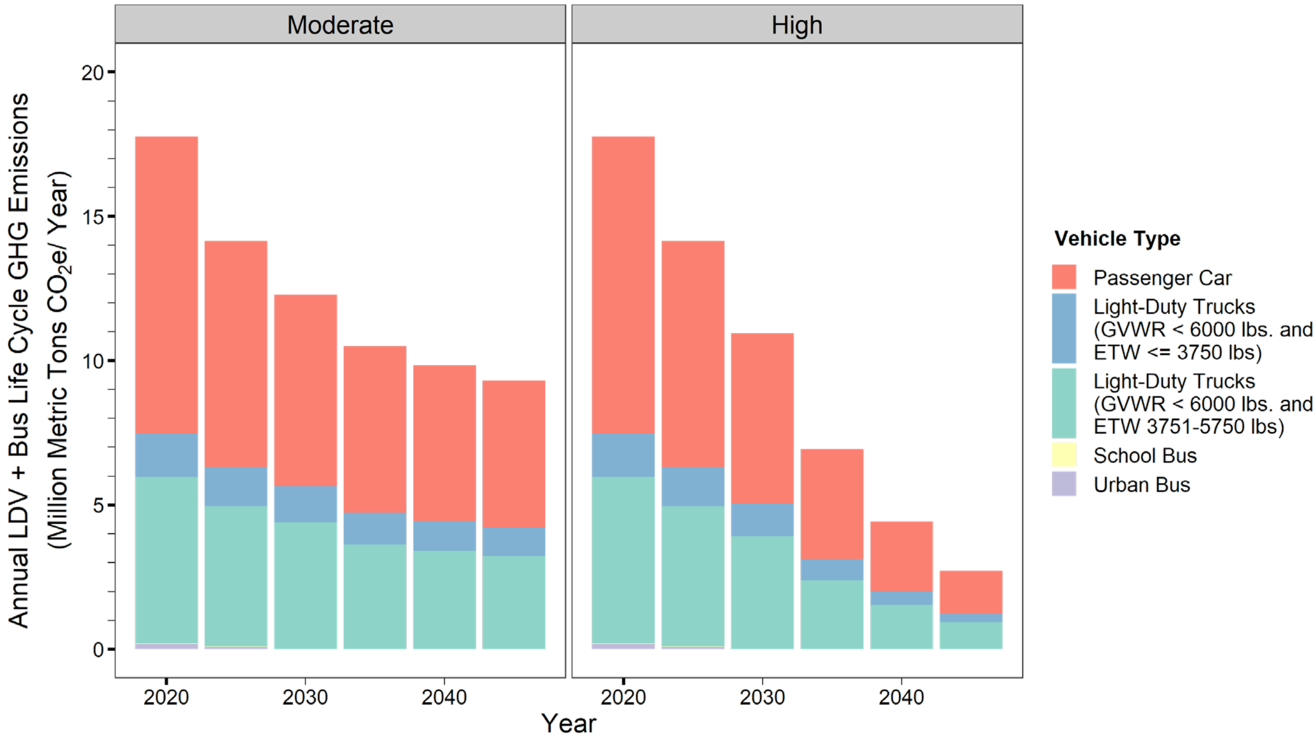


Figure 20. Annual life cycle GHG emissions, by vehicle type and EV adoption projection

See Appendix E, Table 32 for numerical results.
GVWR = gross vehicle weight rating; ETW = equivalent test weight

5 Combined Sector Results

The combined sector results figures presented in this chapter combine the GHG impacts estimated for the power, buildings, and light-duty vehicle sectors, which were presented individually in the preceding sections.

5.1 Combined Combustion Phase GHG Emission Results

Figure 21 illustrates the combustion phase GHG emissions results combined from the three sectors considered in the LA100 study. Scenarios with High load projections ("High") exhibit lower combined combustion GHG emissions compared to the corresponding Moderate load projections ("Moderate") versions of the scenarios due to the more significant reduction in light-duty vehicle sector and buildings sector emissions in the High load projections. Still, light-duty vehicle GHG emissions account for the majority of the combined impacts in most years. By 2045, annual combined combustion GHG emissions in the Moderate load projection scenarios range from 9.6 MMT CO_2e/year in the Early & No Biofuels, Transmission Focus, and Limited New Transmission scenarios to 11.4 MMT CO_2e/year in SB100. In contrast, 2045 combined combustion GHG emissions in the High load projection scenarios range from 2.4 MMT CO_2e/year in Early & No Biofuels, Transmission Focus, and Limited New Transmission to 5.1 MMT CO_2e/year in SB100. SB100 – Stress is comparable to SB100 – High, since the vehicles and buildings combustion GHG emissions are assumed to be identical between those scenarios (the only difference being in the power sector, where emissions are slightly higher in SB100 – Stress). Compared to 2020 levels, the combined annual combustion GHG emissions in 2045 represent a reduction of between 15.8 MMT CO_2e/year (58%) in SB100 – Moderate to 24.8 MMT CO_2e/year (91%) in Early & No Biofuels – High, Transmission Focus – High, and Limited New Transmission – High.

As mentioned earlier in the combustion phase emissions estimates for the power sector, California has established statewide targets of reducing GHG emissions to 40% below the 1990 level by 2030 (SB32) and 80% below 1990 level by 2050 (EO S-3-05). For the combined combustion phase GHG emissions across all three sectors, as shown in Figure 21, we illustrate the range of percentage contributions of the combustion GHG reductions relative to 2020 in each LA100 scenario toward these statewide targets at 2030 and 2045.[19] These contributions range from 7% (SB100 – Moderate) to 10% (Early & No Biofuels – High) of the 2030 target reduction and from 5% (SB100 – Moderate) to 7% (Early & No Biofuels – High, Transmission Focus – High, and Limited New Transmission – High) of the 2050 target reduction.

[19] 2045 is the last model solve year in the LA100 study.

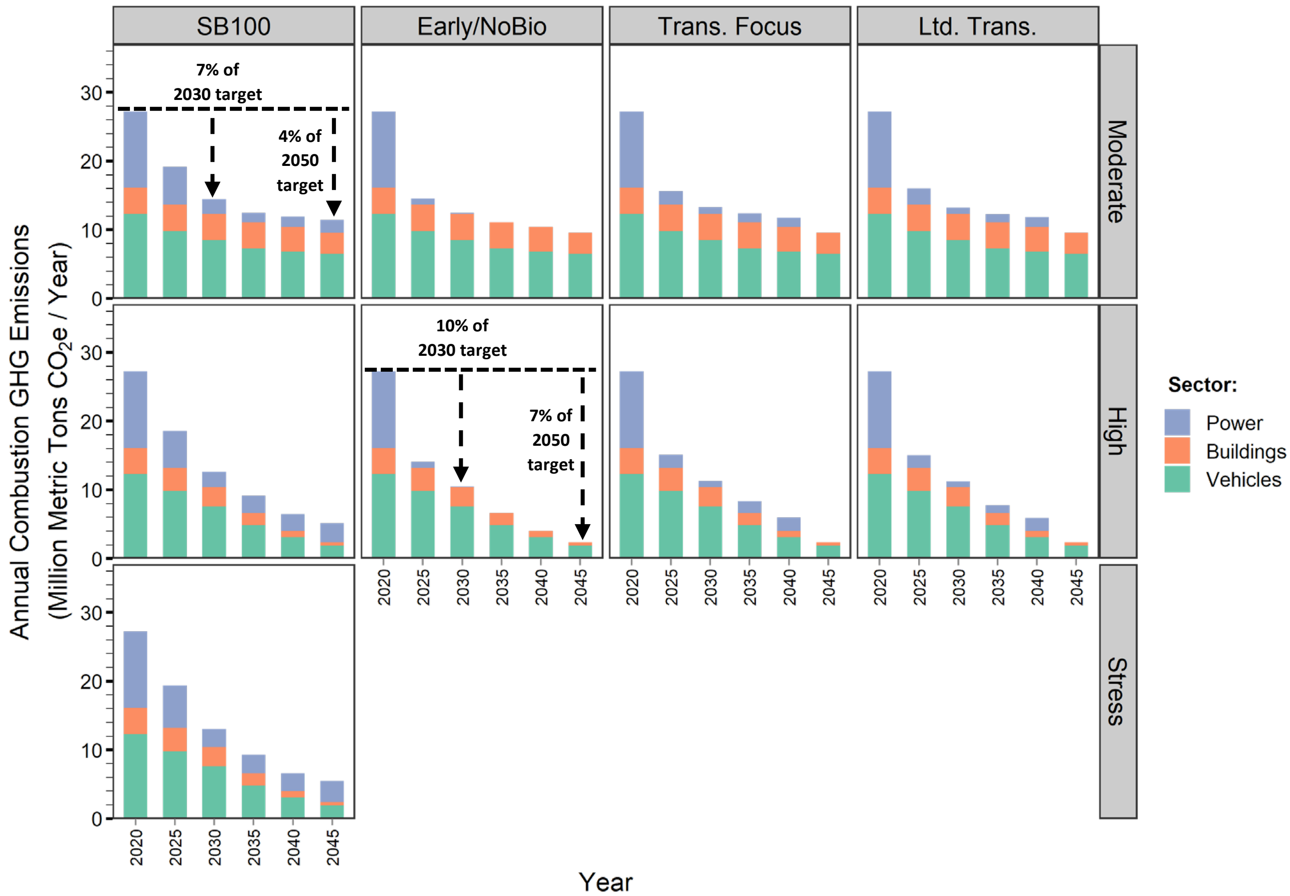


Figure 21. Annual (2020–2045) combustion phase GHG emissions for each LA100 scenario, by year and sector

Comparisons to statewide emissions targets for 2030 (SB32) and 2050 (EO S-3-05) are also shown by the black dashed lines and arrows for the lowest (SB100 – Moderate) and highest (Early & No Biofuels – High)* annual GHG emissions reductions estimated across the full suite of LA100 scenarios.

*Note: Early & No Biofuels – High, Transmission Focus – High, and Limited New Transmission – High have identical 2020–2045 reductions, and so are tied for highest annual GHG emissions reduction.

5.2 Combined Life Cycle GHG Emission Results

Analogous to the combustion-only emissions results presented above, we also report combined life cycle results for the three sectors considered in this analysis. Figure 22 illustrates the annual life cycle GHG emissions for each LA100 scenario. The results generally follow the same trend as the annual combustion-only phase emissions. Scenarios with High load projections ("High") exhibit lower combined life cycle GHG emissions compared to the corresponding Moderate load projection ("Moderate") versions of the scenarios due to the more significant reduction in light-duty vehicle sector and buildings sector GHGs in the former. Still, as in the combustion-only results, light-duty vehicle GHG emissions account for the majority of the combined impacts in most years. By 2045, annual combined life cycle GHG emissions in the Moderate load projection scenarios range from 13.9 MMT CO_2e/year in Early & No Biofuels to 16.2 MMT CO_2e/year in

SB100. In contrast, 2045 combined life cycle GHG emissions in the High load projection scenarios range from 4.2 MMT CO_2e/year in Early & No Biofuels to 7.5 MMT CO_2e/year in SB100. SB100 – Stress is comparable to SB100 – High, since the vehicles and buildings life cycle GHG emissions are assumed to be identical between those scenarios (the only difference being in the power sector, where emissions are slightly higher in SB100 – Stress). Compared to 2020 levels, the combined annual life cycle GHG emissions in 2045 represent a reduction of between 19.3 MMT CO_2e/year (54%) in SB100 – Moderate to 31.3 MMT CO_2e/year (88%) in Early & No Biofuels – High.

Note that unlike in the combustion phase emissions results presented above, life cycle emissions cannot be compared to the California GHG emissions reduction targets. Fuel cycle and life cycle emissions are sums of emissions across both space (they are emitted wherever those activities take place, such as manufacturing PV modules in China) and time (e.g., PV modules manufactured last year being installed and operated this year), so life cycle emissions may occur outside of the geographic scope of California and outside the temporal scope of the study period.

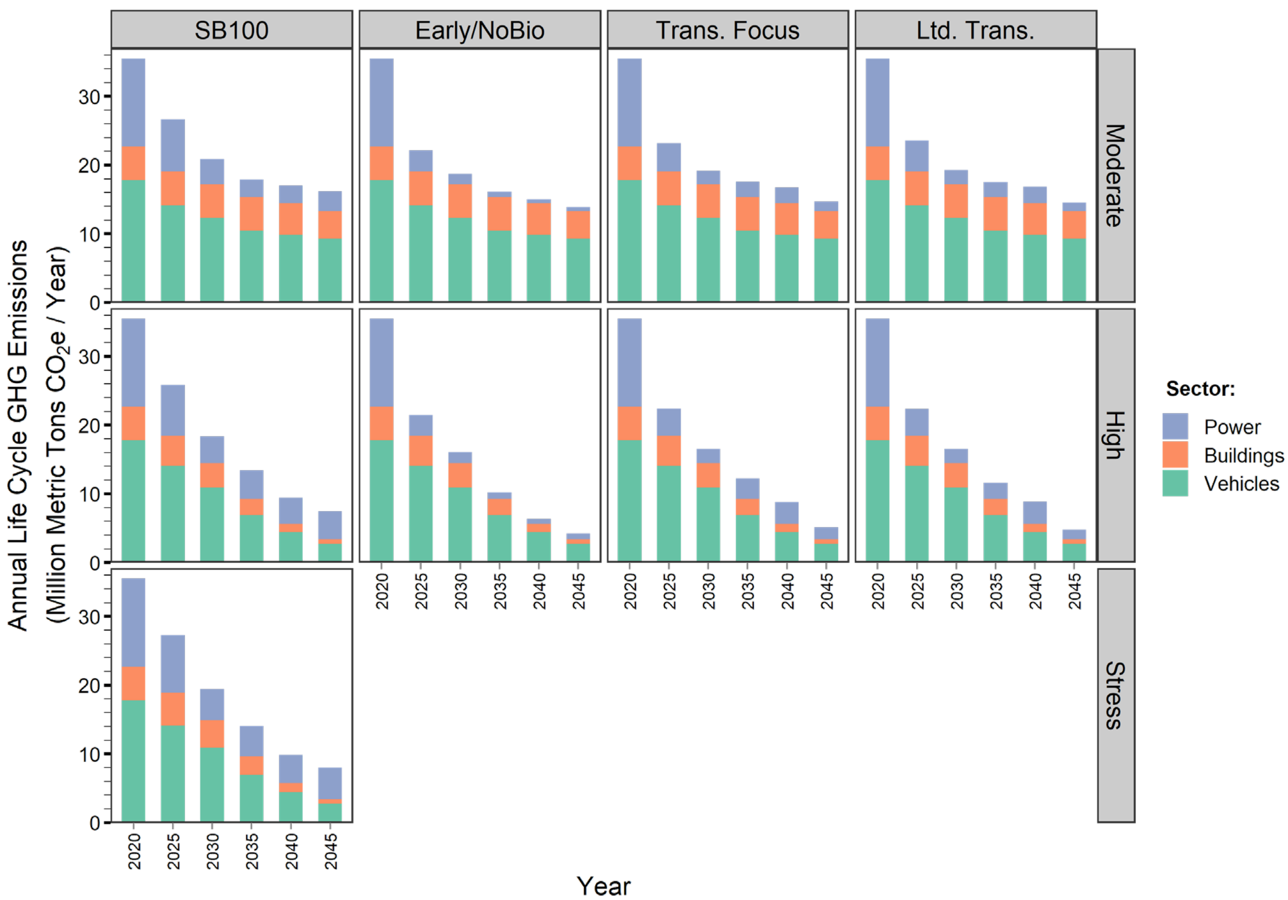


Figure 22. Annual (2020–2045) life cycle GHG emissions for each LA100 scenario, by year and sector

Concluding the results section, Figure 23 displays the cumulative (2020–2045) life cycle GHG emissions for all three sectors, which range from 392 MMT CO_2e in Early & No Biofuels – High to 568 MMT CO_2e in SB100 – Moderate. Across all scenarios and load projections, light-duty vehicle emissions are the largest contributor to the combined life cycle emissions, at between 51% (SB100 – Stress) and 64% (Early & No Biofuels – High) of cumulative emissions.

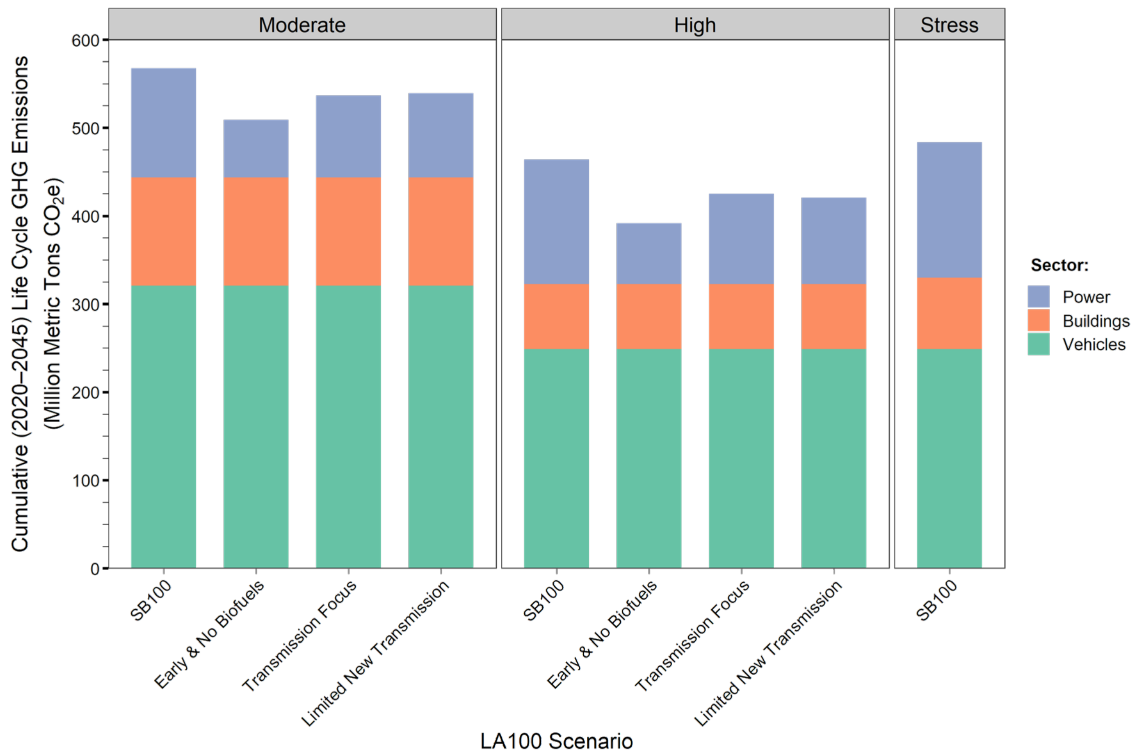


Figure 23. Cumulative (2020–2045) life cycle GHG emissions for each LA100 scenario, by year and sector

Note that all scenarios in the Moderate load projection have identical buildings and vehicles emissions, and likewise for the High/Stress load projections.

6 Monetization Results

Monetized GHG emissions impacts are split into power sector and non-power sector impacts, with power sector numbers differing in every LA100 scenario and non-power sector costs differing among Moderate, High, and Stress cases. Non-power sectors include residential and commercial buildings as well as light-duty vehicles and buses.

Figure 24 shows monetized costs of life cycle GHG figures under the 3% central case discount rate. These total cost figures range from a high of $44.2 billion under SB100 – Moderate to a low of $30.7 billion under Early & No Biofuels – High. These costs do not represent costs of *avoided* emissions, which can only be obtained by comparison. For instance, achieving Early & No Biofuels – High, then, would save $13.5 billion by 2045 compared to SB100 – Moderate.[20] Tabulated results from Figure 24 are shown in Table 3, which can be used to calculate estimates of monetary savings of avoided GHG emissions (or, when differences between scenarios are negative, monetary disbenefits from increased GHG emissions) for any pair of scenarios and load levels.

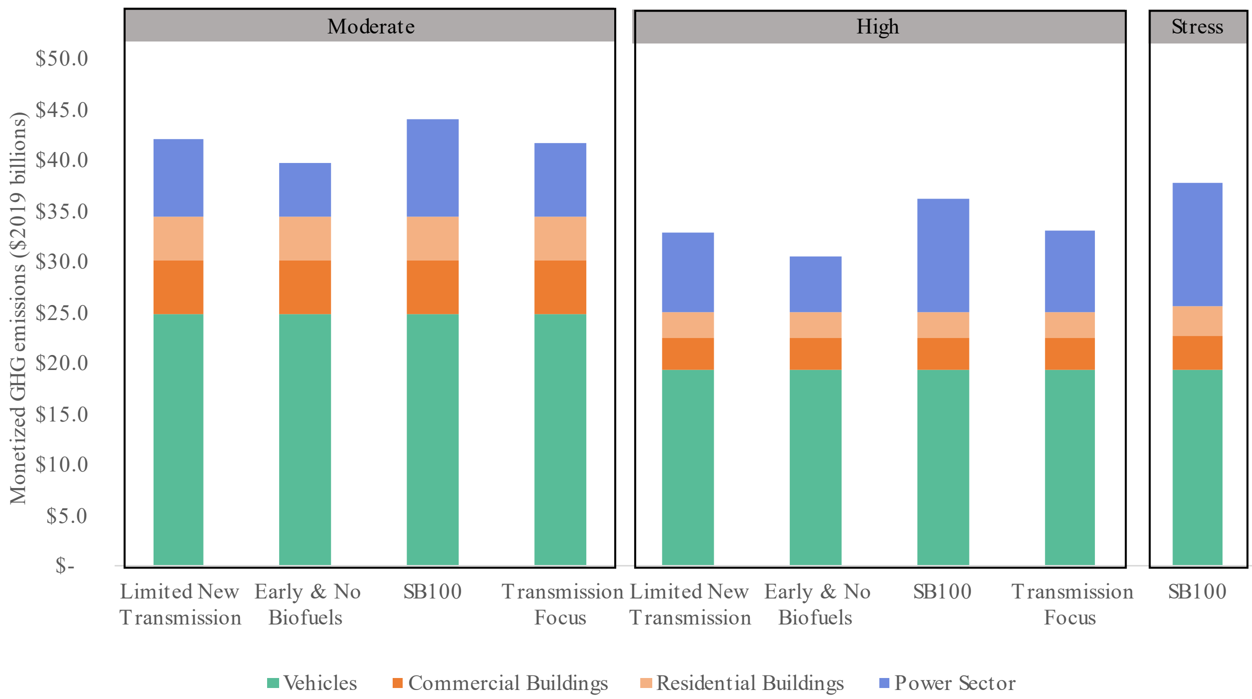


Figure 24. Cumulative monetized costs of life cycle GHG emissions (2020–2045) under a 3% (central case) discount rate

[20] There is no "reference" scenario of GHG emissions in a business-as-usual case without LA100 scenarios. Because of this the savings due to LA100 scenarios cannot be estimated, only comparisons between scenarios.

The majority of GHGs in all scenarios come from vehicles, averaging 58% but ranging from 51% under SB100 – Stress to 63% under Early & No Biofuels – Moderate. Power sector impacts are the lowest after buildings in all Moderate scenarios except SB100, where they are nearly the same as buildings. Under High scenarios, GHG costs from the power sector exceed buildings, except for under Early & No Biofuels, where they are nearly the same.

The distribution of results across scenarios does not change by assumed discount rate, although the magnitude of results does (Table 3). Lower discount rates result in higher present costs of GHG emissions than higher discount rates. The difference between the scenarios with the lowest and highest monetized figures (Early & No Biofuels – High and SB100 – Moderate, respectively) ranges from $5 billion with a 5.0% discount rate to $19 billion with a 2.5% rate.

Table 3. Total Cumulative (2020–2045) Monetized GHGs Costs by Scenario and Discount Rate (2019$ Billions)

		Discount Rate		
		5.0%	**3.0% (Central Case)**	**2.5%**
Moderate	**SB100**	$16 billion	$44 billion	$61 billion
	Early & No Biofuels	$14 billion	$40 billion	$55 billion
	Transmission Focus	$15 billion	$42 billion	$58 billion
	Limited New Transmission	$15 billion	$42 billion	$59 billion
High	**SB100**	$13 billion	$36 billion	$50 billion
	Early & No Biofuels	$11 billion	$31 billion	$43 billion
	Transmission Focus	$12 billion	$33 billion	$46 billion
	Limited New Transmission	$12 billion	$33 billion	$46 billion
Stress	**SB100**	$14 billion	$38 billion	$53 billion

Each scenario presents a range of costs by year that increases over time as due to discounting and the changes in cumulative emissions levels. Table 4 shows these with the 3% discount rate followed by then range of 5% to 2.5% in parentheses. In all cases the highest cost is in 2045 as is the difference between the 2.5% and 5% discounted costs for each scenario.

Table 4. Range of Cumulative Monetized Costs of GHGs Over Time (2019$ Billions)

		2035	2040	2045
Moderate	SB100	$27 ($8.7–$38)	$36 ($12–$50)	$44 ($16–$61)
	Early & No Biofuels	$24.2 ($7.9–$34)	$32 ($11–$45)	$40 ($14–$55)
	Transmission Focus	$24.9 ($8.1–$35)	$33 ($12–$47)	$42 ($15–$58)
	Limited New Transmission	$25.1 ($8.2–$36)	$34 ($12–$47)	$42 ($15–$59)
High	SB100	$24.7 ($8.1–$35.1)	$31 ($11–$43)	$36 ($13–$50)
	Early & No Biofuels	$22 ($7.2–$31)	$27 ($9–$38)	$31 ($11–$43)
	Transmission Focus	$23 ($7.4–$32)	$29 ($10–$40)	$33 ($12–$46)
	Limited New Transmission	$24 ($7.7–$33)	$29 ($10–$41)	$33 ($12–$46)
Stress	SB100	$25 ($8.2–$36)	$31 ($11–$44)	$38 ($14–$53)

Table 5 shows the cumulative cost of power sector GHG emissions alone through 2045 by scenario. The largest overall difference at the 3% discount rate is between the Early & No Biofuels – Moderate scenario ($5.2 billion) and the SB100 – Stress scenario ($12 billion). The difference between these two, $6.9 billion, represents the monetized savings due to cumulative GHG emission reductions from achieving the Early & No Biofuels scenario relative to the SB100 scenario.[21]

Table 5. Cumulative Cost of Power Sector GHG Emissions (2020–2045) (2019$ Billions)

	Discount Rate		
	5.0%	**3.0% (Central Case)**	**2.5%**
SB100 – M	$3.5	$9.6	$13
Early & No Biofuels – M	$1.9	$5.2	$7.2
Transmission Focus – M	$2.6	$7.3	$10
Limited New Transmission – M	$2.7	$7.5	$11
SB100 – H	$4.0	$11	$15
Early & No Biofuels – H	$2.0	$5.5	$7.7
Transmission Focus – H	$2.9	$8.0	$11
Limited New Transmission – H	$2.8	$7.7	$11
SB100 – S	$4.3	$12	$17

[21] Appendix F contains further comparisons of scenarios. Positive differences reflect savings or a benefit of one scenario compared to the other while negative differences represent a cost of a scenario relative to the other.

Non-power sector estimates are distinguished by the Moderate, High, and Stress load projections. Because the load projections relate to the electrification of end uses (light-duty vehicles and buildings), higher levels of electrification have greater reductions in fuel consumption and associated GHG emissions.

Under the High load electrification projection, the total discounted cost of GHG emissions by 2045 ranges from $9.0 billion to $35 billion, with $25 billion being the central 3.0% rate case. The vast majority of this—77%—comes from the electrification of vehicles. Buildings account for $5.7 billion; this sum is slightly higher for commercial compared to residential.

Table 6. Cumulative (2020–2045) Monetized Costs of Non-Power Sector Life Cycle GHG Emissions Under High Electrification (2019$ Billions)

Discount Rate	Commercial Buildings	Residential Buildings	Light-Duty Vehicles	Total
5.0%	$1.1	$0.9	$7.0	$9.0
3.0% (Central Case)	$3.1	$2.6	$19	$25
2.5%	$4.3	$3.7	$27	$35

This basic trend is continued under the Moderate electrification scenario, although vehicles account for slightly less of the total with 72%. The range between low and high monetized GHG totals is greater than the High electrification case, with a difference of $35.6 billion between the low of $12.4 billion and high of $48.0 billion under the 2.5% discount rate.

Table 7. Cumulative (2020–2045) Monetized Costs of Non-Power Sector Life Cycle GHG Emissions Under Moderate Electrification (2019$ Billions)

Discount Rate	Commercial Buildings	Residential Buildings	Light-Duty Vehicles	Total
5.0%	$1.9	$1.6	$9.0	$12
3.0% (Central Case)	$5.2	$4.4	$25	$35
2.5%	$7.3	$6.1	$35	$48

Cumulative non-power sector GHG costs under the SB100 – Stress scenario fall between those for High and Moderate electrification, although they are only slightly greater than the High scenario. In this case the range is from $9.2 billion to $36 billion, differences of $0.2 and $0.8 billion, respectively.

Table 8. Cumulative (2020–2045) Monetized Costs of Non-Power Sector Life Cycle GHG Emissions Under SB100 – Stress (2019$ Billions)

Discount Rate	Commercial Buildings	Residential Buildings	Light-Duty Vehicles	Total
5.0%	$1.2	$1.0	$7.0	$9.2
3.0% (Central Case)	$3.4	$2.9	$19	$26
2.5%	$4.7	$4.0	$27	$36

When comparing the highest and lowest non-power sector monetized GHG cost scenarios (Moderate and High electrification), High results in a total of $9.4 billion in monetized savings from avoided GHG emissions by 2045 under a 3.0% discount rate. The majority of these savings, 59%, come from light-duty vehicles. Savings from commercial and residential buildings are close to one another, although the commercial figure is $0.4 billion higher.

Table 9. Non-Power Sector GHG Savings Under High Compared to Moderate Electrification (2019$ Billions)

Discount Rate	Commercial Buildings	Residential Buildings	Light-Duty Vehicles	Total
5.0%	$0.8	$0.6	$2.0	$3.4
3.0% (Central Case)	$2.1	$1.7	$5.6	$9.4
2.5%	$3.0	$2.4	$7.7	$13

7 Limitations and Caveats

Several limitations should be understood when interpreting the results of the LA100 GHG emission analysis:

7.1 Power Sector

- The analysis employs point estimates of life cycle GHG emissions and thus produces a point-estimate life cycle GHG result. The point estimates of per-phase life cycle GHG emissions except combustion represent the median of ranges from a comprehensive review of the LCA literature. Yet, GHG emissions associated with each phase in the specific case of the application of these technologies by LADWP may differ from the median, but without having specific foreknowledge in great technical detail about the future application, it is impossible to more accurately discern what true future emissions will be. However, we believe that the scale of deployment of these technologies, the diversity of technologies deployed, and the range of years over which these technologies will be deployed can mitigate any bias in these estimates and tend toward the median. Thus, in aggregate, we would not expect dramatic errors in the overall result. For specific technologies like biofuels, issues like indirect land use (as discussed below) could cause greater error, yet as currently modeled this technology is not significantly utilized.
- We consider GHG emissions associated with generator infrastructure only; GHG impacts from the addition or retirement of other electric infrastructure (e.g., transmission lines, distribution lines, substations) are not included. This caveat is particularly important when considering the results of the Transmission Focus scenarios.
- Electricity generation from biomass is captured in the RE-combustion turbine technology. This technology is assumed to start as 100% animal waste biogas[22]-based generation capacity which then transitions to 100% hydrogen-fueled generation by the final model solve year (2045). For the calculation of non-combustion phase GHG emissions, a linear interpolation of the emissions factors between 100% biogas (2020) and 100% H_2 (2045) is assumed for the intervening years. Combustion phase emissions are assumed to be zero in all years for RE-combustion turbine technology. Upstream and downstream emissions factors are assumed to be identical to those for NG-combustion turbine technology.
- There is ongoing scientific debate concerning the magnitude of GHG emissions associated with changes in land use directly or indirectly induced by the cultivation of a biomass feedstock. However, given that the assumed biofuel used in RE-combustion turbine technology in the LA100 scenarios is exclusively waste biogas, there would be no induced change to land use, and therefore the potential effects of indirect land use change on life cycle GHG emissions from biofuel generation technologies are not applicable.
- A concern commonly raised regarding the increasing integration of variable renewable power generation sources into the existing set of generators in electrical grids is that the GHG emissions reduction impacts of variable renewable generation may be offset in part by the increased flexibility, ramping, and part-loading required of conventional fossil generators to ensure a supply-demand balance. Part-loading of fossil generators, for example, decreases the efficiency of the plants and therefore creates a fuel efficiency and GHG emissions penalty relative to a fully loaded plant. Note that this effect could occur on LADWP-owned facilities and other facilities connected to LADWP in the WECC, though it is expected to be relatively small in comparison to the reduction in power-sector

[22] Emissions factors for animal waste biogas obtained from CA-GREET 3.0.

GHG emissions resulting from the switch to 100% renewable resources. However, the production cost modeling in LA100 does capture changes in efficiency from non-steady-state operation of fossil generators, so this effect is inherently included in the GHG impacts reported in this chapter. Further discussion is provided in the footnote for context.[23]

- Assumptions were made to align the technology category definitions of the available LCA literature with production cost modeling definitions. The assumptions in the bulleted list below introduce some uncertainty, but they are not expected to directionally bias the results to any significant degree.
    - Concentrating solar power (CSP) systems with and without storage produce the same life cycle GHG emissions.
    - Utility- and customer-scale PV produce the same GHG emissions.
    - "Battery" is assumed to be represented by lithium-ion batteries (LIB). See Appendix A for more detail on the methodology for estimating life cycle GHG emissions factors for stationary grid-scale LIB technology.
    - Long-duration storage is assumed to be represented by hydrogen (H_2) storage combined with fuel cell regeneration, labeled as "Fuel Cells" in the results figures. See Appendix A for more detail on the methodology for estimating life cycle GHG emissions factors for stationary grid-scale hydrogen storage technology.
    - Combustion turbines burning hydrogen (labeled as "H_2 – Combustion Turbine") are assumed to have the same upstream and downstream emissions as conventional natural gas combustion turbines (NG-CT) and the same non-combustion emissions as Fuel Cells. Hydrogen-fueled combustion turbines have no combustion phase GHG emissions.
- The life cycle GHG emission factors used in the analysis are based on published estimates. With the exception of putting the estimates on a common functional basis (g CO_2e / kW or g CO_2e / kWh), no additional harmonization of methods was performed. Inconsistent methods can lead to greater variability among reported results than would result if studies used common definitions, scope, boundaries, and other methods. Harmonization of methods could reduce this inconsistency, but harmonized life cycle GHG emission factors per life cycle stage were not produced in the LCA Harmonization Project (see for more information: "Life Cycle Assessment Harmonization," NREL,

[23] Gross et al. (2006), for example, performed a literature review of the costs and impacts of variable renewable energy generation, including analyses of the fuel savings and GHG emissions impacts of wind energy. The efficiency penalty due to the variability of wind power output (and its impact on the operations of the conventional generation fleet) in four studies that explicitly addressed the issue ranged from near 0% to as much as 7%, for up to 20% wind electricity penetration. Pehnt et al. (2008) calculated an emission penalty of 3%–8% for a wind electricity penetration of 12%, with the range reflecting varying types of conventional power plants built in future years. Fripp (2011) finds that, in larger regions (more than 500 km) where geospatial smoothing can be significant, the operating reserves required for wind generation will undo less than 6% of the GHG emissions savings that would otherwise be expected. As summarized by Gross and Heptonstall (2008), at least for moderate levels of wind electricity penetration, "there is no evidence available to date to suggest that in aggregate efficiency reductions due to load following amount to more than a few percentage points." Nonetheless, it is clear that efficiency penalties associated with part-loading and ramping fossil generation may modestly impact the carbon emissions savings of high-penetration renewable energy futures, although storage, interruptible load, and any flexibility offered by renewable energy supply (e.g., CSP with storage) would mitigate those penalties to some degree. Additional research is needed to assess the degree of the degradation of the remaining fossil generation plants under the 80%-by-2050 renewable energy scenarios considered in NREL (2012), because those impacts are not quantified in this report.

https://www.nrel.gov/analysis/life-cycle-assessment.html). Although the lack of methodological consistency introduces some uncertainty, it is not expected to directionally bias the results.

- GHG emission estimates reported in the literature are sometimes reported as CO_2, CO_2e, or the mass of individual GHG species. Estimates of CO_2 and CO_2e will both be used in the same pool to calculate the median GHG emission factors. Studies reporting individual GHGs were converted to CO_2e using Intergovernmental Panel on Climate Change global warming potentials (see EPA 2017). Not accounting for all GHG emissions leads to an underestimation of total GHG emissions, but it is not expected to be significant in magnitude.
- The LCA literature continues to evolve. The LCA estimates to be used in the LA100 study represent a recent point in time of the evolution of this literature and may not represent changes in conclusions within the community at a later date. However, given the quantity of literature already analyzed, the results are not anticipated to change significantly because of ongoing literature review and analysis.

7.2 Non-Power Sector

- GHG emissions from the non-power sector are limited in scope to residential and commercial buildings, light-duty vehicles, and transportation buses. This scope excludes, for instance, all privately and publicly owned industrial sources of GHG emissions, including large emission sources such as the Port of Los Angeles and Los Angeles International Airport (LAX).
- Only fuel-use-related GHG emissions are assessed in the LA100 study. Upstream and downstream GHG emissions from the manufacturing or decommissioning phases of the infrastructure/appliances/vehicle life cycle are not included. The study also does not include emissions related to the infrastructure stock turnover from electrification. Analysis of GHG emissions from building, appliance, and vehicle turnover is potentially a topic for future study.
- The emission factor for natural gas relies solely on conventional natural gas extraction and does not consider renewable natural gas (RNG) technologies. While industry goals of incorporating RNG technology in the future have been identified, there is currently no law or enforceable order in California which would require such a transition to RNG sources.
- Combustion emissions for non-renewable fuels are evaluated as point estimates based on the output of the fuels in the CA-GREET3.0 model (from which most of the emissions factors used in this analysis were obtained); they are held constant across all years and are based on the carbon content of each fuel.
- The uncertainty of the point estimates for the carbon intensity of each fuel, activity factors, and vehicle fuel economy are not considered in this study. The point estimates for each value are the single, best estimate based on available data.
- The LA100 analysis extends through 2045; however, the CA-GREET3.0 model does not include projections for years beyond 2040. To avoid extrapolating in a time period where data may later be available, carbon intensities for each fuel in years following 2040 are assumed to be equal to the carbon intensities from 2040.
- Data on assumed vehicle miles traveled per year (VMT) and the proportion of non-electric vehicles using each fuel type (gasoline, diesel, compressed natural gas) in three of the vehicle classes (passenger cars, light-duty trucks, and urban buses) were obtained from CARB's EMFAC model. For school buses, the fleet fuel-type composition and VMT estimates were chosen to align with those of buses in the Los Angeles Unified School District (LAUSD), as used in other aspects of the LA100 study. The known, current LAUSD fleet fuel types[24] were found to be different from the assumed

[24] https://achieve.lausd.net/Page/2735

fuel-type composition given in the EMFAC model for school buses in the LA subregion. See Appendix B for an estimated distribution of VMT for the LAUSD school bus fleet.

7.3 Monetization of GHG Costs

- Monetized GHG estimates are based on values produced in 2017 by the IWG. Values per unit of gas emitted depend on a wide range of quantitative factors captured in IAMs along with financial parameters but are forward looking and therefore inherently limited due to lack of knowledge about the future. Changes in empirical observations and developments in scientific understanding will likely drive changes to future revisions of these estimates.
- GHG emissions are global and as such values are also global and cannot be localized to one specific area such as LA. These costs should be interpreted as the contribution of LA100 scenarios to worldwide costs from GHG emissions.
- Monetized GHG emissions are flat figures by year and discount rate and do not differentiate between small- and large-scale changes that could cause compounding effects. Small scale changes, for example, incur costs but may not cause discernable changes in technology while large-scale changes may drive technological changes that would more significantly affect changes in the dollar value per unit of emissions. Large changes may also affect consumption of different combinations of goods and services while small changes may not drive similar activity. IWG figures show a middle range between potential scales of change and associated costs.
- Estimates of GHG costs are only from quantifiable changes and do not include subjective values such as quality of life.

8 Summary

In closing, this chapter estimates changes in GHG emissions in the power, buildings, and transportation sectors for the LA100 study on both a combustion and life cycle basis.

In the power sector, all LA100 scenarios show substantial reductions in combustion GHG emissions by year 2045. In all LA100 scenarios, LADWP's assets exceed commensurate contribution to the statewide 40% and 80% GHG reduction targets for 2030 and 2050, respectively. Because Early & No Biofuels reaches the 100% renewable energy target 10 years earlier, this scenario has the lowest cumulative GHG emissions (combustion and life cycle) for the power sector in the study period, about half those of the SB100 set. Power sector GHG emissions from life cycle stages outside of fossil fuel combustion account for between 31% and 52% of cumulative (2020–2045) emissions.

The High load projection of natural gas consumption in the buildings sector is significantly lower than the Moderate load projection—equivalent to the cumulative (2020–2045) emissions generated by 100,000 average U.S. homes' energy usage.[25] Reductions in natural gas usage in residential buildings in the High and Stress load projections equates to approximately 86% reduction in annual GHG emissions from 2020 to 2045 for both projections. The commercial buildings results are similar.

In the vehicle sector, annual GHG emissions reductions from reduced fossil fuel consumption in the High EV adoption projection in 2045 compared to 2020 are equivalent to those from about 170 days' worth of Los Angeles County current gasoline consumption,[26] about 1.7 billion gallons of gasoline. Approximately 99% of GHG impacts in the vehicle sector come from passenger cars and light trucks, with the remaining 1% of impacts attributed to urban and school buses.

The cumulative costs of GHG emissions from 2020–2045 range from $30.7 billion to $44.2 billion (2019$) depending on the scenario and under a central 3% discount rate. The highest costs are associated with the Moderate load scenarios due to higher emissions in the buildings and transportation sectors: $39.7 billion under Early & No Biofuels to $44.2 billion under SB100. The lowest costs are associated with the High scenarios, and in particular Early & No Biofuels, which has the least cumulative GHG emissions: $30.7 billion, compared to a high of $36.1 billion under SB100. The cumulative GHG monetized costs for only the power sector range from $5.2 billion to $12.1 billion (2019$) (Early & No Biofuels – Moderate to SB100 – Stress, respectively; 3% discount rate). The cumulative GHG costs from non-power sectors range from $25.1 to $34.5 billion (2019$) (Moderate and High projections, respectively; 3% discount rate), the majority of which is due to vehicle-related GHG emissions. Recall that monetized

[25] At 2019 emissions levels.

[26] At 2017 consumption levels: "LA County Annual Gasoline and Diesel Fuel Sold (Million gallons per year)," County of Los Angeles, https://data.lacounty.gov/dataset/LA-County-Annual-Gasoline-and-Diesel-Fuel-Sold-Mil/3cnn-cvz8.

benefits from GHG emissions consider global benefits whereas those from air pollution are strictly local to the city of LA.

9 References

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Appendix A. Power Sector Methodology and Emissions Factors

Appendix A provides an overview of the GHG emission analysis methodology and includes tables of emissions factors used in each life cycle stage as well as the methodology used to derive the two storage technology emissions factors calculated specifically for this study—lithium-ion batteries and hydrogen storage.

A.1 GHG Analysis Methodology

Broadly, GHG emission from LA100 scenarios are determined both for those resulting from combustion of fossil fuels in LADWP-owned facilities and those attributable to all generation technologies across their life cycle.

Estimating CO_2 emissions from combustion based on the product of generation per technology category and/or unit and a CO_2 EF for that category/unit is one approach to GHG impact analysis. However, such an estimation scheme does not consider several other components of GHG emissions attributable to electricity generation:

- Only emissions from the combustion of fossil energy would be counted, whereas emissions from upstream fuel extraction and processing would be disregarded.
- Only CO_2 emissions would be considered in that case, while other GHG emissions (e.g., methane (CH_4), nitrous oxide (N_2O)) would be ignored; this may be particularly important for methane released in coal mining, oil production, and natural gas production and transport, as well as any emissions of non-CO_2 GHGs released through combustion processes. CO_2 equivalents (CO_2e) must be used.
- A focus on combustion-only emissions means that the implications of GHG emissions from equipment manufacturing and construction, and O&M activities, and plant decommissioning are not considered, which can be usefully categorized into four life cycle stages:
  - Plant construction (called “upstream” in life cycle assessment [LCA] literature)
  - Plant operating emissions, which are further disaggregated into:
    - Those associated with fuel combustion for electricity generation
    - All other emissions during plant operation including those associated with obtaining the fuel (called combustion and operating, non-combustion, which includes the “fuel cycle”)
    - Plant decommissioning (or “downstream”).
  - (See Figure 25 for a conceptual depiction of these stages.)

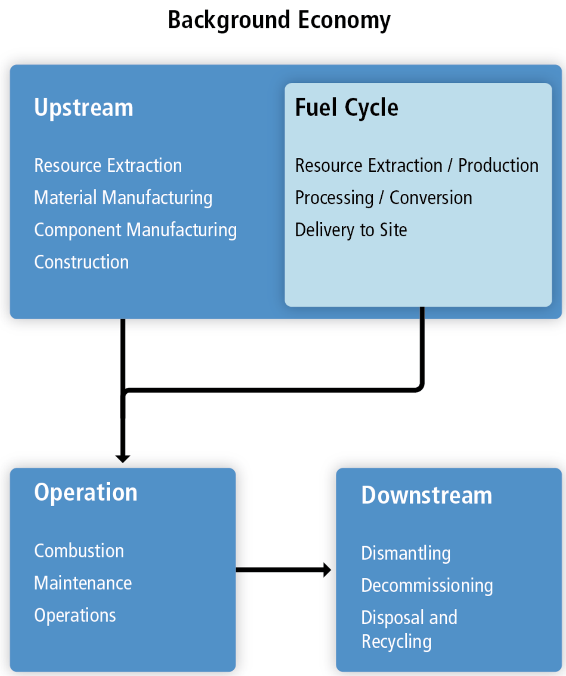

Figure 25. The four life cycle stages that are considered in LCA literature

Upstream considers the resource extraction, material and component manufacturing, and construction of a generation plant. Fuel Cycle applies to fossil and nuclear fuel supply chains, as well as to bioenergy, and is encompassed in the upstream stage including fuel resource extraction and production, processing and conversion, and delivery to site. Operation includes combustion and O&M. Downstream includes the dismantling, decommissioning, disposal and recycling of the plant assets. Figure reference: Sathaye et al. 2011.

As a result, although most renewable electricity technologies have no or limited operational GHG emissions (with the exception of biopower[27]), a more comprehensive evaluation of the impact of LA100 scenarios requires that GHG emissions across the full life cycle of each technology be evaluated employing internationally accepted LCA procedures. In the results presented in this chapter, we show that this is especially important for the LA100 study because the life cycle phases outside of combustion can contribute as much as half of cumulative (2020–2045) GHG emissions in some scenarios (e.g., the Early & No Biofuels scenarios set).

Our approach to estimating changes in attributable GHG emissions from LA100 scenarios combines output from production cost modeling in PLEXOS of fuel combustion, electricity generation, and capacity additions/decommissions (as modeled in the study's capacity expansion model, RPM) with literature-based estimates of life cycle GHG emissions for LADWP assets. To support the assessment of non-combustion emissions, we have conducted a comprehensive and systematic review of the LCA literature for more than 7 years to create a database of GHG emission factors (per unit generation or capacity; see below), disaggregated by the four life cycle stages. These estimates were compiled under NREL's seminal LCA Harmonization Project (see "Life Cycle Assessment Harmonization," NREL, https://www.nrel.gov/analysis/life-cycle-assessment.html), with updates for most renewable technologies in support of more recent studies such as the Renewable Electricity Futures Study (NREL 2012), Wind Vision (DOE 2015), Hydropower Vision (DOE 2016), and Geothermal Vision (DOE 2019). Collected literature went through two rounds of strict screening to be considered in the analytical phases of the LCA Harmonization Project. (Further information about the screening process for the LCA Harmonization Project is detailed in the Renewable Electricity Futures Study, Appendix C (NREL 2012).) Out of more than 2,000 references screened, about 300 were used as the basis to compute life cycle GHG emission factors. Figure 26 summarizes the results of this review for a wide range of renewable and non-renewable electricity generation technologies, including the full range of published estimates of life cycle GHG emission factors for each technology. Life cycle GHGs are measured in grams of CO_2 equivalents per kilowatt-hours (g CO_2e/kWh).[28]

[27] Combustion of biomass emits CO_2 and other GHGs. However, because the carbon emitted during combustion is absorbed during photosynthesis in feedstock production, these emissions cancel when summed over the life cycle. The impacts of combustion-only CO_2 emissions reported in this chapter assume no net emissions from biopower facilities, consistent with a recent US EPA policy decision on 'Programmatic Treatment of Biomass and the Forest Products Industry' (Pruitt, 2018) which treats biogenic CO_2 emissions resulting from the combustion of biomass from managed forests at stationary sources for energy production as carbon neutral. Nevertheless, there are non-cancelling GHG emissions from biopower systems outside of the biomass production and combustion processes associated with component manufacturing and construction; O&M; and, often, feedstock production. All of these GHG emissions were accounted for here in the life cycle estimates. However, unaccounted for altogether in our prior studies as well as for LA100 are potential GHG emissions associated with changes in land use directly or indirectly induced by the cultivation of a biomass feedstock. See Section 7.1 of this chapter for further discussion of this issue.

[28] Minor note: All greenhouse gas emissions accounted for are converted into CO_2 equivalents using global warming potentials (GWP) to allow for comparisons of the impact of different gases. GWP measures the amount of energy the emissions of 1 ton of a gas will absorb over a given period, relative to the emissions of 1 ton of carbon dioxide (CO_2) The time period used is usually over 100 years. See EPA (2017).

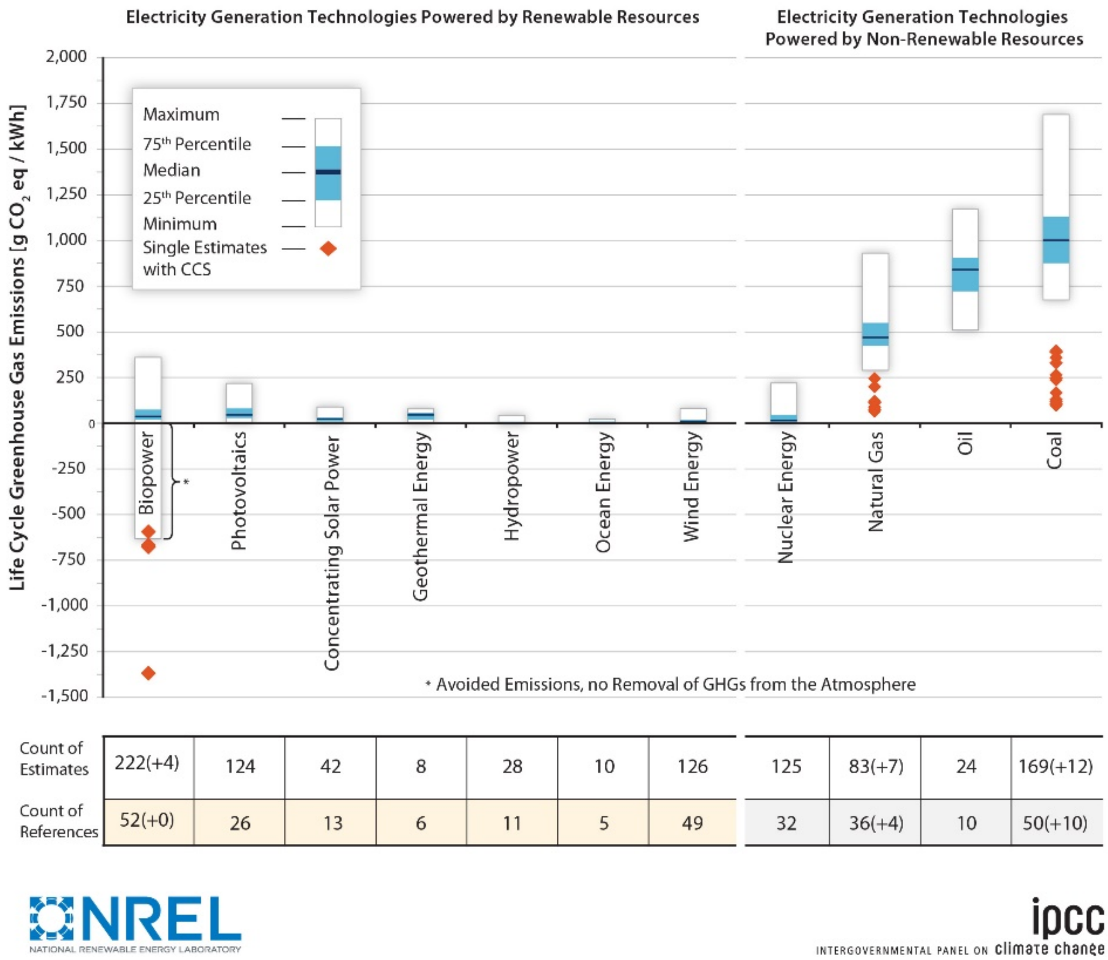

Figure 26. Synthesis of literature estimates of life cycle greenhouse gas emissions (g CO_2e / kWh) for electricity generation technologies powered by renewable and non-renewable resources

Figure source: Sathaye et al. (2011)

The references passing the LCA Harmonization Project's systematic review were then further analyzed to develop GHG emission factors for each life cycle phase. The definition of each phase and our analytical approach are described below:

One-time upstream emissions, which include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, and on-site construction. These emissions occur once in the lifetime of a generation unit. Emission factors used in the analysis of this life cycle stage are median estimates taken from the results of the LCA Harmonization project.

Ongoing non-combustion operational emissions during the operating phase, which include fuel-cycle emissions (where applicable) and emissions resulting from non-combustion-related O&M activities. These emissions occur each year the plant operates. Emission factors used in the analysis of this life cycle stage are median estimates taken from the results of the LCA Harmonization project.

Ongoing combustion emissions, resulting from combustion at the power plant (where applicable) for the purpose of electricity generation. These emissions occur each year the plant operates. Emission factors used in the analysis of this life cycle stage are calculated from EPA eGRID using 2018 reported, generator-specific fuel burn (MMBTU) and CO_2 emissions (short tons) (EPA 2020).

One-time downstream emissions, which include emissions resulting from facility decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the generation assets and other site materials. These emissions occur once in the lifetime of a generation unit. Emission factors used in the analysis of this life cycle stage are median estimates taken from the results of the LCA Harmonization project.

Table 10 lists the one-time emissions (upstream and downstream) related to the embodied emissions of a generation unit, which are largely determined by the unit's size (capacity). For the LA100 study, the PLEXOS model aligns with RPM's output of capacity installed and retired, by technology. Multiplying literature-estimated, one-time upstream GHG emissions normalized per kilowatt of installed (retired) capacity by the capacity changes reported by the PLEXOS model yields an estimate of GHG emissions associated with the addition (retirement) of that technology's capacity. Note that the PLEXOS and RPM models report cumulative capacity additions and retirements every 5 years, so interim model years do not have associated upstream or downstream additions.

Table 10. Emissions Factors for Upstream and Downstream Phases, by Technology

Technology	One-Time Upstream GHG Emission Factor ($g\ CO_2e/\ kW$)	One-Time Downstream GHG Emission Factor ($g\ CO_2e/\ kW$)
CAES[29]	--	N/A
Coal[30]	N/A	67,100
Concentrating Solar Power	2,970,000	239,000
Customer PV	1,630,000	37,800
Customer Storage	527,000	98,900
Fuel Cells[31]	370,000	N/A
Geothermal[32]	2,345,000	18,400
H2-Combustion Turbine[33]	64,790	2,600
NG-Combustion Turbine[34]	64,790	2,600
NG-Steam/Combined Cycle	100,000	4,070
Nuclear	N/A	175,000
Pumped Hydro Storage	800	N/A
RE-Combustion Turbine[35]	64,790	2,600
Utility Battery Storage	527,000	98,900
Utility PV	1,630,000	37,800
Utility PV + Battery[36]	1,630,000 (PV); 527,000 (Battery)	37,800 (PV) 98,900 (Battery)
Wind	619,000	14,000

[29] Upstream CAES emissions were not measured and are assumed to be negligible.
[30] Emissions factors for coal were multiplied by 262,800 lifetime hours (amount in hours for a plant running for 30 years). (Whitaker et al., 2012)
[31] Upstream H_2 storage emissions factor assumes manufacturing of electrolyzer, compressed storage, and fuel cell. See Section A.3 Hydrogen Storage Emissions Factors Methodology for further details.
[32] Derived from per-kWh emissions factors in Eberle et al. (2017) by assuming 25-year lifetime and 70% capacity factor.
[33] Upstream and downstream GHG emissions factors for H2-Combustion Turbine technology are assumed to be identical to those of NG-Combustion Turbine.
[34] Specific estimates for NG-Combustion Turbine (NG-CT) were not available in the literature for upstream and downstream emissions factors, so estimates for NG-CC from Heath et al. (2014) were adjusted by the ratio of thermal efficiencies for NG-CC and NG-CT.
[35] Upstream and downstream GHG emissions factors for RE-Combustion Turbine technology are assumed to be identical to those of NG-Combustion Turbine.
[36] For Utility PV + Battery technology, the PV and battery capacities are modeled distinctly in PLEXOS; therefore, we assign individual emissions factors to the respective capacities (upstream and downstream phases) or generation (non-combustion phase) of each and then aggregate GHG calculations from the two components.

Ongoing combustion emissions are mainly related to the production of electricity by burning fossil fuel. The PLEXOS model reports fuel burn (MMBTU) by unit. The generator-specific emissions factors used in the analysis of this life cycle stage are calculated from EPA eGRID using reported, generator-specific fuel burn (MMBTU) and CO_2 emissions (short tons) for year 2018. Calculated emissions factors (as reported in Table 11) are applied to PLEXOS output of fuel burn for each combustion generator in each modeled year. Interim year values are linearly interpolated in between the 5-year timestep solve years.

Table 11. Emissions Factors for Combustion Phase, by Generator, Derived from 2018 eGRID Data

PLEXOS Model Generator Name	Technology	2018 eGRID Fuel Burn (MMBTU)	2018 eGRID CO_2 Emissions (short tons)	Ongoing Combustion GHG Emission Factor (g CO_2e / MMBTU)
Harbor10B[37]	NG-CC	43,7836	25,678.4	53,205
HarbrLCT10	NG-CT	25,405	1,493.6	53,335
HarbrLM61	NG-CT	23,819	1,402.8	53,428
HarbrLM62	NG-CT	21,699	1,276.1	53,351
HarbrLM63	NG-CT	18,170	1,068.4	53,343
HarbrLM64	NG-CT	20,276	1,198.4	53,619
Haynes GT1	NG-CT	446,263	26,037.2	52,930
Haynes GT2	NG-CT	162,026	9,452.5	52,925
Haynes GT3	NG-CT	765,460	44,659.5	52,928
Haynes GT4	NG-CT	106,813	6,232.6	52,935
Haynes GT5	NG-CT	628,582	36,673.5	52,928
Haynes GT6	NG-CT	558,546	32,587.5	52,928
Haynes1	NG-Steam	489,044	28,533.4	52,930
Haynes10[38]	NG-CC	19,695,122	1,149,482.7	52,946
Haynes2	NG-Steam	342,124	19,961.1	52,929
Intrmnt repower LDWP_1539[39]	NG-CC	NA	NA	53,269
Intrmnt1	Coal	38,614,855	3,961,885.1	93,077
Intrmnt2	Coal	44,319,460	4,547,181	93,077
MRCHN23C[40]	NG-CC	15,885,648	944,084.9	53,914
Scattrgd RP CC[41]	NG-CC	12,237,018	714,640.5	52,979
Scattrgd1	NG-Steam	812,144	47,429.3	52,980
Scattrgd2	NG-Steam	458,358	26,767.3	52,978
VALLEY[42]	NG-CC	11,110,963	648,443.5	52,944
VllyLM61	NG-CT	40,298	2,372	53,398

[37] Harbor10A is included with Harbor10B in the RPM/PLEXOS specification
[38] Haynes 9 is grouped with Haynes 10 in the RPM/PLEXOS specification.
[39] Planned NG-CC plant at Intermountain is assumed to have a combustion EF equal to the weighted average of the other NG-CC generators.
[40] This model generator represents Apex Generating Station.
[41] Scattergood CT Units 6 and 7 are included in the NG-CC generator representation.
[42] This model generator includes Units 6, 7, and 8 at Valley Generating Station.

Ongoing, non-combustion GHG emission factors are assigned by technology type, as reported in Table 12. Estimates of GHG emissions associated with the fuel cycle and other non-combustion-related ongoing activities are derived by multiplying literature-estimated, ongoing non-combustion-related GHG emissions normalized per kilowatt-hour by PLEXOS-estimated generation. As with ongoing combustion emissions, interim-year ongoing non-combustion emissions are linearly interpolated in between the 5-year timestep solve years.

Table 12. Emissions Factors for Ongoing Non-Combustion Phase, by Technology

Technology	Ongoing Non-Combustion GHG Emission Factor (g CO_2e/ kWh)
CAES[43]	—
Coal	16.9
Concentrating Solar Power	2.5
Customer PV[44]	9.4
Customer Storage	0
Fuel Cells	2.5
Geothermal	6.9
H_2-Combustion Turbine[45]	2.5
Hydro	4
NG-Combustion Turbine	68
NG-Steam/Combined Cycle[46]	105
Nuclear	10.6
Pumped Hydro Storage	36
RE-Combustion Turbine[47]	2.5–38
Utility Battery Storage	0
Utility PV	9.4
Utility PV + Battery[48]	9.4 (PV); 0 (Battery)

[43] Non-combustion CAES emissions were not measured and are assumed to be negligible.
[44] NREL (2013) estimates 21%–26% of total life cycle GHG emissions for PV technologies come from the operation and maintenance phase. Non-combustion emissions for all PV technologies assumed to be 23.5% (midpoint of 21%–26%) of the total 43 g CO_2e / kWh.
[45] H_2-Combustion Turbine non-combustion emissions are assumed to be identical to those of the Fuel Cells technology
[46] The “Ongoing Non-Combustion” EF for NG-CC was calculated based on Heath et al. (2014), which reports that 77% of life cycle GHG emissions of NG-CC comes from combustion, with the remainder assumed to non-combustion, ongoing emissions (mainly from the fuel cycle) (Heath et al. 2014).
[47] RE-Combustion Turbine non-combustion emissions vary over the modeled period, since this technology starts as 100% biogas-fueled in 2020 and is 100% H_2-fueled by 2045. The biogas non-combustion emissions factor, derived from CA-GREET 3.0, is approximately 38 g CO_2e/kWh, whereas the H_2 non-combustion emissions factor is identical to that of Fuel Cells. Intervening year emissions factors are linearly interpolated within this range.
[48] See Footnote 36.

Wind	0.7

Summing GHG emissions over all years, life cycle phases, technologies, and generators included in the LA100 study yields estimates of cumulative life cycle GHG emissions for each scenario in the study. As displayed in Equation 1 below, a given scenario's GHG Emissions (*E*) (in g of CO_2e) are estimated by the summation of two sums calculated in each modeled year (*y*) from 2020 to 2045. The first summation, over the set *T* of all technologies (*tech*) allowed to be installed or retired, is composed of three terms: 1) the product of one-time upstream GHG EF (*u*) (in g CO_2e/kW) and new installed capacity (*I*) (in kW) reported by the PLEXOS model; 2) the product of the one-time downstream GHG EF (*d*) (in g CO_2e/kW) and the retired capacity (*R*) (in kW) reported by the PLEXOS model; and 3) the product of non-combustion (*n*) GHG EF (in g CO_2e/kWh) and Generation (*G*) (in kWh) reported by PLEXOS. The next sum, over the set *H* of all LADWP combustion generators modeled in PLEXOS, has one term: the product of combustion (*c*) GHG EF (in g CO_2e/MMBTU) and fuel burn (*F*) (in MMBTU) reported by PLEXOS. Note that emissions factors *c*, *d*, *n*, and *u* are defined in Tables Table 10–Table 12 above; variables *I*, *F*, *G* and *R* are outputs reported by the PLEXOS model.

Equation 1:

$$E = \sum_{y=2020}^{2045} \left[\left(\sum_{tech \in T} u_{tech} * I_{y,tech} + d_{tech} * R_{y,tech} + n_{tech} * G_{y,tech} \right) + \left(\sum_{gen \in H} c_{gen} * F_{y,gen} \right) \right]$$

A.2 Battery Storage Emissions Factors Methodology

To estimate aggregate GHG emissions for the LA100 study, life cycle GHG emissions factors for all technologies built in the modeled scenarios had to be quantified. The PLEXOS modeling for this study includes capacity additions of 'Utility Battery Storage,' 'Utility PV + Battery', and 'Customer Storage'. In all three of these technologies, the storage capacity is assumed to operate as a grid-tied lithium-ion battery (LIB). However, a comprehensive LCA literature review for LIB technology had not been undertaken as part of the LCA Harmonization project; the first review of LCA analysis of this technology has only recently appeared in the literature (Pellow et al. 2019). Using the compilation of LCA literature in Pellow et al. (2019) as a guide, a systematic review of the life cycle assessment (LCA) literature on LIB technologies was conducted to obtain the "Generic Storage" GHG emission factors (per unit generation or capacity) for each of the relevant life cycle stages.

LCA Literature Screening

The compiled LIB LCA literature was screened using similar methods to the Harmonization Study, although a full LCA harmonization was beyond the scope of this project. In keeping with the Harmonization project's approach for estimating GHG emissions factors for other technologies, the LIB studies went through two screenings of predefined criteria. These screens ensured comparability and relevance to the LA100 study.

The first screening isolated literature that:

- Had a consistent set of included life cycle phases (e.g., system boundary) and metrics (e.g., global warming potential);
- Was written in English;
- Was published recently (2004 or later);
- Was published as a peer-reviewed journal article, book chapter, thesis, dissertation, or report;
- Covers stationary storage applications;
- Reports quantitative results from an LCA or reviews results from multiple LCAs.

The second screen evaluated technical qualities:

- Quality:
    - Uses a currently accepted LCA protocol as defined by the International Organization for Standardization (ISO)
    - Uses a relevant impact assessment method
    - Transparency and Completeness:
    - Reports methodology transparently with regard to key parameters, assumptions and methods (e.g., defines a system boundary)
    - When key assumptions or data (such as life cycle inventories or breakdowns of GHGs by phases) were not provided in the main publication text, they were accessed via the supporting information or from the corresponding author
    - Provides a numerical description of the system characteristics (i.e., the functional unit under study)
    - Reports the environmental impact estimates quantitatively
    - Provides citations for data sources and, if appropriate, reports the name of the LCA software or database used for the analysis
    - Reports original results (i.e., the result is not cited from prior work)
    - Provides enough information to convert to units of gCO_2e/kW (e.g., energy to power ratio, power rating and mass, grid application)
- Relevance:
    - Evaluates a modern or near-future stationary storage system (see Limitations and Caveats for further details).

Of the 61 studies analyzed, five studies passed all screens. The main excluding factor was the stationary application requirement. Only six of the 61 studies focused on stationary applications.[23] Most published LIB LCAs focus on use in mobile applications (e.g., electric

[23] Six additional studies of the 61 focus on ‘second-life’ EV batteries for grid applications, but these were excluded under the assumption that LIB capacity would be produced from primary sources. Furthermore, the allocation of attributable emissions between the primary function in EVs and a secondary reuse on the grid is unclear. See section Upstream and Downstream Phases for further discussion.

vehicles, or EVs)[24] and literature directly pertaining to stationary LIB LCAs is very limited (Peters et al. (2017); Pellow et al. (2019)). Of the six, only one—Rydh and Sanden (2005)—was excluded because it was older than 10 years and only presented environmental impacts in terms of cumulative energy demand.

Upstream and Downstream Phases

Table 13 shows a summary of the five stationary LIB LCA studies that passed both literature screens.

Table 13. Summary of the Five Stationary LIB LCA Studies Included in the GHG EF Estimates

Author (Year)	LIB Cathode Chemistries*	Upstream GHG Emissions Factors (g CO_2e / kW)	Downstream GHG Emissions Factors (g CO_2e / kW)
Baumann et al. (2017)	LFP	719,000	-
	LTO	1,230,000	-
	LMO	540,000	-
	NMC	510,000	-
	NCA	530,000	-
Hiremath et al. (2015)	Average of LFP, NMC, and NCA	690,000	-
McManus (2012)	LFP	16,700	-
Ryan et al. (2018)	LFP	17,200	-
	LMO	17,400	-
	NMC	19,600	-
	NCA	18,600	-
Vandepaer et al. (2018)	LFP	860,000	113,000
	LMP	720,000	86,000
Median emissions factors:		527,000	99,000

* Battery chemistry abbreviations: LFP= lithium-iron-phosphate; LTO = lithium-iron-phosphate with lithium-titanate anode; LMO = lithium-manganese-oxide; NMC = lithium-nickel-cobalt-manganese-oxide; NCA = lithium-nickel-cobalt-aluminum-oxide; LMP = lithium-metal-polymer

While many LIB LCAs report impacts in terms of energy capacity (g CO_2e / kWh), the upstream and downstream LIB emissions factors for the LA100 study need to be in power capacity units (g CO_2e / kW) to align with the other technologies' upstream and downstream emissions factors and to enable them to be applied to PLEXOS-reported capacity additions/retirements (in units of kW). All but one of the five passing literature sources, Ryan et al. 2018, report impacts in terms of energy capacity (kWh), so it was necessary to convert to power capacity units (kW) in a

[24] EV batteries were not appropriate for inclusion in the LIB emissions factors. See section Mobile vs. Stationary Applications of LIBs for further discussion.

consistent manner. This conversion was made using energy-to-power ratios (E/P ratios) or the combination of mass and power rating, when reported. In the absence of such specifications, a mean E/P ratio of those given in the literature for LIBs operated for time shifting applications (6 hrs) was assumed.

There are several factors which may lead to differences in calculated LIB emissions factors, which differ by more than an order of magnitude in the upstream phase across the five studies. Firstly, emissions factors vary widely by LIB application, and the screened LCA sources do not all assess the same applications. Secondly, the lowest upstream estimate, McManus (2012), only includes cradle to gate impacts (which is not a full life cycle) and, furthermore, does not include any components other than the cells. Thirdly, variations in the LCA study designs and key assumptions vary from study to study (e.g., functional units, retirements thresholds, degradation rates).

LIBs have many potential applications for grid services and many LIB LCAs that study grid-scale storage define how the battery will operate on the grid. Grid applications each have defined discharge durations and power ratings, which match the needs of the grid service provided. One example is energy time shifting, which requires large amounts of electricity to be delivered over the span of several hours. This may be used to store energy produced by solar PVs during the day so that it can be used in the evening when those solar PVs are not producing energy. In contrast, frequency regulation is characterized by numerous short discharges of power. This is used by system operators to balance power grid systems and maintain stability. Accordingly, a battery's application has implications for sizing (as well as lifetimes), which can greatly affect life cycle impacts.

Consideration of the downstream decommissioning impacts of stationary LIBs is scant in the literature; Ryan et al. (2018) and Vandepaer et al. (2018) are the only stationary LIB LCAs to pass both literature screens and include the end of life (EoL) phase in their system boundary. However, the EoL impacts estimated by Ryan et al. are not included in our EoL emissions factors because they are not isolated as a separate phase; these authors only include EoL as a displacement of virgin material production, ignoring the impacts of recycling or landfilling. Thus, Vandepaer et al. (2018) is the only screened stationary LIB LCA to provide quantified EoL impacts. This source does note that there are many uncertainties in the direction of future LIB end-of-life pathways and impacts.

Operational Phase Impacts

The operation phase of the stationary LIB life cycle is often reported as the most significant component of cumulative life cycle GHG emissions (Baumann et al. 2017; Hiremath et al. 2015; Ryan et al. 2018; Vandepaer et al. 2018; Pellow et al. 2019). This conclusion is typically arrived at by noting the difference in GHG emissions between electricity generation during hours of high renewables fraction when the time-shifting LIB is charged compared to the emissions from sources that would have been used during the period when the LIB energy is discharged. For the LA100 study, however, any such impacts are already captured in the generation profiles output from the PLEXOS models. Therefore, we exclude ongoing (non-combustion) GHG impacts for LIB technology from this analysis, assuming impacts from O&M, as well as from the BOS, are negligible.

Mobile vs. Stationary Applications of LIBs

It is unclear whether non-stationary LIB LCAs, such as those focused on EV batteries, could be used to supplement the dearth of stationary LIB LCA literature. Pellow et al. state that the EV literature could be relevant for stationary LIB analysis if battery chemistries and especially cell configurations are similar. However, they caution that balance of system (BOS) components and application remain key differences between stationary and non-stationary LIBs.

Though we did not include any LCAs of EV batteries that have been repurposed for grid storage after being retired (i.e., second-life EV batteries), this may be a trend to investigate in the future. The subject has started to receive some attention in the LCA literature in recent years (Faria et al. 2014; Richa et al. 2015; Ahmadi et al. 2017; Casals et al. 2017; Bobba et al. 2018; and Cusenza et al. 2019). The method for allocating impacts between the primary function of EV usage and the secondary function as grid storage is an open area of research (Cusenza et al. 2019). EV batteries are retired when capacity degrades to about 70%–80% (Neubauer et al. 2015). Retired EV batteries could become part of a circular economy through reuse as grid energy storage and could be suited for many grid applications, once repurposed (Bobba et al. (2018); Burke (2019)). This second-life reuse has the potential two-fold benefit of lessening environmental impacts from both the EoL phase of EV batteries and from the production of virgin grid-scale batteries.

Limitations and Caveats

There are several limitations and caveats that come with this generally conservative approach to estimating LIB emissions factors used in the LA100 study:

- It was beyond the scope of this project to focus on any single LIB chemistry or develop a weighted average of GHG emissions factor estimates; a simple median estimate across all chemistries is assumed.
- All components of the energy storage system, including battery cells and housing, are assumed to have the same lifetime. In reality, battery cells reach their end of life faster than their aluminum casings and concreate foundations. When the LIB battery reaches the end of its useful life, the cells will need to be replaced, but the BOS components could likely be reused (assuming the location of storage need remains the same). In the case where battery capacity is retired and immediately replaced at the same generation location, we make a conservative assumption to avoid underestimation in our emissions estimates for the LA100 scenarios by applying the full impacts of EoL to retired capacity and the full upstream impact to the replacement capacity.
- Assumed LIB storage lifetime is 15 years.

A.3 Hydrogen Storage Emissions Factors Methodology

One of the technology options that has been incorporated into the RPM and PLEXOS models for the LA100 study is long duration or "seasonal" storage. Compared to LIBs, this technology is characterized by much higher storage capacities and longer discharge times which enable it to function in a time shifting application on much longer time scales. Instead of shifting electricity from low-demand hours to high-demand hours like LIBs, long duration storage can shift energy on the time scale of months. RPM and PLEXOS model capacity additions of long duration storage as grid-scale, stationary hydrogen (H_2) storage. For the purposes of the GHG analysis, we make an additional assumption that this H_2 storage would consist of three components: 1) an electrolyzer that uses electricity from the grid to convert water into hydrogen and oxygen, 2) a tank where the hydrogen produced in the electrolyzer can be compressed and stored, and 3) a fuel cell that generates electricity from the stored hydrogen at a later date. Round trip efficiency for this electricity-to-hydrogen-to-electricity storage system is assumed to be 45% in RPM and PLEXOS.

As with the LIB technology, a comprehensive LCA literature review for hydrogen storage had not been undertaken as part of the LCA Harmonization project. Therefore, a systematic review of the LCA literature on electrolyzers, storage tanks, and fuel cell technologies was conducted to obtain the long duration storage GHG emission factors (per unit generation or capacity) for each of the relevant life cycle stages. The same screening criteria were used for LIB and hydrogen storage LCA literature; for details on what these criteria entail, see LCA Literature Screening in Section A.2.

Out of the total of 31 literature sources reviewed, four studies passed both screens and were used to calculate median hydrogen storage life cycle GHG emissions factors. Two of the included sources—Ghandeharium 2016; Spath and Mann 2004—specifically deal with hydrogen storage from grid charging but do not include the fuel cell component. Given the scarcity of LCA literature in this space, these studies were not excluded and were used only in the estimation of the electrolyzer and compression/storage components of the upstream emissions factor. Similarly, Oliveira et al. (2015) only reports grid-scale fuel cell manufacturing impacts and is only included in the calculation of the median fuel cell upstream portion. Furthermore, all studies reported life cycle impacts per kilogram of hydrogen produced or per kWh of power, but for the LA100 study purposes, upstream emissions factors need to be per unit of capacity (kW). The per-kg H_2 EF estimates were first converted to per-kWh estimates by dividing by the product of the lower heat value of hydrogen (33 kWh / kg) and the assumed round-trip efficiency of the storage system (45%). The per-kWh estimates were then converted to per-kW estimates by assuming the same lifetime generation as the system modeled in Khan et al. (the only literature source to report results for all three components and to report impacts both per unit of generation and per unit of capacity). The result of compiling emissions factors and converting to consistent units is summarized in Table 14.

Table 14. Summary of the Four Grid-Scale Hydrogen Storage LCA Studies Included in the GHG EF Estimates

Source	Estimated Compression/ Storage?	Estimated Electrolyzer?	Estimated Fuel Cell?	Compression/Storage + Electrolyzer (g CO_2e / kW)	Fuel Cell (g CO_2e / kW)
Ghandehariun (2016)	✓	✓		259,000	—
Khan et al. (2005)	✓	✓	✓	197,000	275,000
Spath and Mann (2004)	✓	✓		253,500	—
Oliveira et al. (2015)			✓	—	49,000
System component median estimates:				234,700	162,000
Total Median Upstream H_2 Storage EF (g CO_2e / kW):				396,700	

Operational Phase Impacts

Similar to LIB, hydrogen storage LCA literature generally discuss use-phase GHG impacts of hydrogen storage operation in terms of changes to grid electricity source patterns (i.e., those resulting from time shifting energy from low-demand to high demand period). It is not feasible to disaggregate the ongoing emissions attributed exclusively to O&M from the these (likely more significant) time shifting emissions attributed to the operational phase. Since impacts of time shifting are already captured in the PLEXOS outputs, we exclude the use-phase impacts of long-duration storage and assume that any O&M GHG impacts are negligible.

End of Life (EoL) Impacts

No retirement of H_2 storage capacity occurs in any of the LA100 scenario results presented in this chapter, so determining a downstream emissions factor for this technology was not prioritized. For completeness, however, we did make a note of literature discussion (and ideally quantification) of H_2 storage decommissioning GHG impacts. Of the four LCA literature sources which passed the two screens, just two mention EoL GHG impacts, and one, Oliveira et al. (2015), only reports a so-called “infrastructure” GHG emissions factor which combines upstream and EoL impacts. Only Khan et al. (2005) quantitatively isolate the downstream emissions factor for the H_2 electrolysis, storage and fuel cell system, which they report to be 1.85 g CO_2e/kWh, or just 9% of the total 19.89 g CO_2e/kWh.

Limitations and Caveats

As with the LIB methodology, there are several limitations and caveats that come with this generally conservative approach to estimating the H_2 storage emissions factors used in the LA100 study:

- The upstream emissions factor assumes a fuel cell will be used to generate electricity from the stored hydrogen. There are other technologies that could be used, such as combusting the hydrogen in a combined-cycle gas plant (AlRafea et al. 2016). The scope was restricted to fuel cell re-electrification only, given time constraints and the relatively small contribution of H_2 storage capacity builds in the LA100 scenario outputs.
- As with the LIB technology, all components of the H_2 storage plus fuel cell system are assumed to have the same lifetime.
- Assumed H_2 storage lifetime is 20 years (Khan et al. 2005).

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Appendix B. Non-Power Sector Methodology and Emissions Factors

B.1 Introduction

The LA100 study aims to develop and investigate transition pathways for LADWP-owned power generation assets to achieve 100% renewable energy, resulting in significant GHG emission reductions from the power sector. An important aspect of the LA100 study is consideration of changes to load sectors in ways that could impact where, how much, and in what sectors power is required in the future. Electrification of end uses that currently utilize combustion of fossil fuels, especially when combined with decarbonization of electricity supply, results in additional GHG emission reduction benefits arguably attributable to the LA100 scenarios being investigated. The methods to quantify these additional GHG emission reduction benefits of the LA100 scenarios are the subject of this appendix.

Broadly, NREL uses an analogous approach for quantifying GHG emissions from the non-power sectors as for the power-sector, with some important exceptions. As for the power sector, our non-power sector GHG emission accounting considers fossil fuel use in all years from 2020–2045, both annually and cumulatively. As stated above, we are tracking fossil fuels used in residential and commercial buildings as well as in the light-duty vehicle and bus fleets that are modeled within LA100. We consider all major fuels combusted: natural gas used in buildings (both commercial and residential) for space and water heating and cooking, gasoline and diesel used in all vehicle fleets, as well as natural gas and propane used exclusively in the bus fleets. The GHGs considered for each fuel are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOC), and carbon monoxide (CO).[49]

Like for the power sector, non-power sector GHG emissions are considered on a direct combustion emission and a life cycle basis. As a brief reminder, the “life cycle” is defined as all activities attributable to a final product, including all inputs required to make that product (called “upstream” activities) and also to manage the product at the end of its useful life (called “downstream” activities), where the use of the product fits in the middle (called the “operation” phase). To illustrate this for electricity generation, the life cycle of power generation from a natural gas-fueled power plant is shown in Figure 27. As shown, it takes into account the construction, operation and decommissioning of the plant (the vertical axis on the right side of the figure), as well as the “fuel cycle” (see labeled box within Figure 27) which is the life cycle for the natural gas used to fuel the plant.

[49] Other potential GHGs, such as black carbon, organic carbon, and nitrous oxides (NOx), are listed in the CA-GREET3.0 model developed by the California Air Resources Board (CARB) but are not included in the final GHG value. This is the default assumption of the CA-GREET3.0 model and aligns with the requirements of the California Low Carbon Fuel Standard (LCFS), which does not count GHG emissions from black carbon, organic carbon, or NOx.

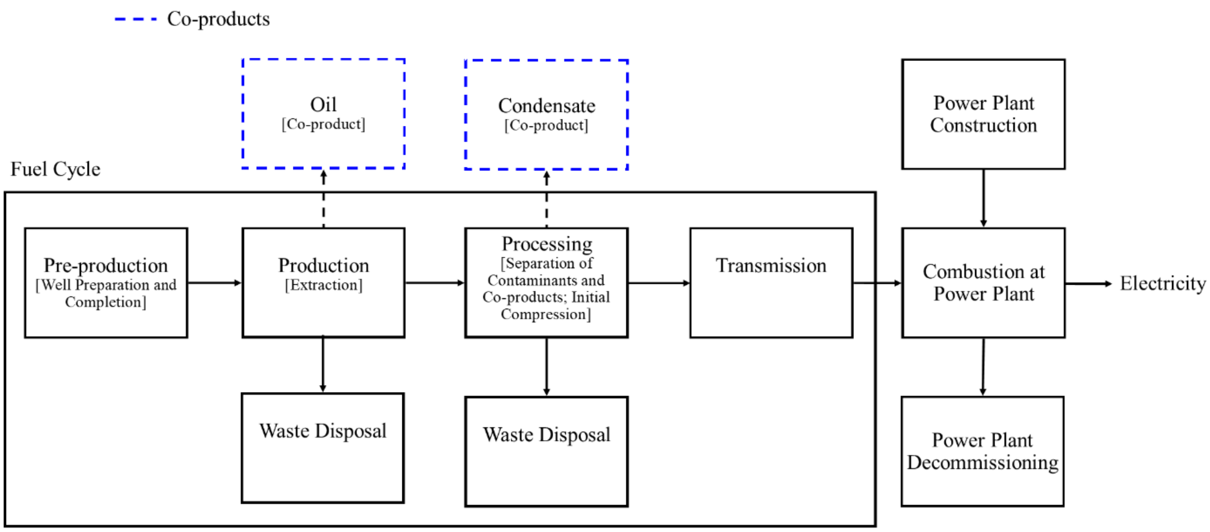

Figure 27. Process flow diagram depicting the life cycle of a natural gas-fired power plant generating electricity, with the fuel cycle for the natural gas fuel highlighted

For the non-power sector, we are quantifying GHG emissions from fossil fuels. During its "operation" the fuel is combusted, which emits GHGs. The upstream for the fuel combusted is shown by example for natural gas in Figure 27, labeled as the fuel cycle. There is no downstream for the fuel since it is eliminated by its combustion.

The important distinction between the power sector life cycle GHG emissions accounting and non-power sector GHG emissions accounting is that the infrastructure in which the fuel is combusted is considered in our power sector analysis, but not considered for our non-power sector analysis. The detailed accounting required to quantify embodied GHGs from constructing/manufacturing all of the different types of vehicles and end-use appliances in buildings, let alone their end-of-life disposal, is beyond the scope of this analysis. And yet, just like in the power sector, the vast majority of GHG emission attributable to non-power sector activities is from fossil fuel combustion.

GHG emissions from fossil fuels used in buildings and vehicles modeled in LA100 are estimated as the product of fuel use (gallon, mcf) and GHG emissions per unit of fuel used. The first is generically called "activity" and the second is called an "emission factor." Each of the below sections outlines how we estimate each of those two factors for all non-power sector sources considered.

The methods used for estimating fuel use in the non-power sector, as well as the corresponding GHG emission factors, have been selected to align with methods approved by the State of California (CA). The models we use for determining baseline and projected GHG emissions are specific to the State of California, and to the Los Angeles metropolitan area when more specific inputs are available. The tools used to estimate non-power fuel use have been used to estimate power sector GHG emissions from the LA100 study, or are tools developed by the California Air Resources Board (CARB). These methods and tools are discussed in greater detail in the following sections.

B.2 Methods to Estimate Building Fuel Use

Fuel use from residential and commercial buildings was estimated with the ResStock™[50] and ComStock™[51] models, which were developed by NREL with funding from the U.S. Department of Energy (DOE). ResStock and ComStock are used to estimate certain energy-relevant characteristics of the residential and commercial building stock, respectively, within a selected geographic region. For the LA100 study, both of these models have been applied to the LADWP service area, using statistical methods to create baseline and projected energy requirements for fuel use from modeled end uses. When fuels are used in residential and commercial building stock, this fuel is assumed to be natural gas. Initial results indicate that the next highest fuel used in residential and commercial buildings is propane. However, because only approximately 0.3% of residential housing units and no commercial units use this type of fuel within the LADWP service area, its use is considered de minimus with regard to GHG emissions and not considered further.

ResStock and Comstock follow the same four-step process to determine fuel requirements:

12. **Building Stock Characterization:** Probability distributions are created for approximately 100 building characteristics. Data sources used to develop these distributions can be found in Appendix A of this chapter.
13. **Statistical Sampling:** The probability distributions are sampled to create sets of building characteristics, which are used to create building energy use models in OpenStudio/EnergyPlus,[52] DOE's building energy simulation platform.
14. **Baseline Simulations:** The building energy models output subhourly fuel demand values for a simulated year of operation. Typical end uses for both ResStock and ComStock include but are not limited to water heating, space heating, drying, and cooking.
15. **Model Validation:** Simulated building fuel use is determined for model years 2015–2017, which is then compared to LADWP data on actual fuel use for those years and adjusted to match actual totals.

The baseline building stocks modeled by ResStock and ComStock are then used to capture changes in building energy usage in future years based on projections of population (building stock) and economic growth, adoption of more energy-efficient appliance and management practices, and the rate of appliance electrification. The projections include targets specific to California and LA for technology and performance standards (e.g., California Title 24). Other building stock changes included within the projections include:

- **Changes in Building Stock Turnover** – the rate of demolition and construction of new buildings projected by the CA Dept. of Finance as well as Dodge Data and Analytics Metropolitan Construction Insight (applies to both residential and commercial building stocks).

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[50] "ResStock Analysis Tool," NREL, https://www.nrel.gov/buildings/resstock.html.
[51] "ComStock Analysis Tool," NREL, https://www.nrel.gov/buildings/comstock.html.
[52] EnergyPlus is a whole-building energy simulation program that engineers, architects, and researchers use to model energy consumption. Its development is funded by the U.S. Department of Energy's Building Technologies Office. See "EnergyPlus," DOE, https://energyplus.net.

- **Changes in Appliance and Fuel Use Efficiency** – In ResStock, the percentage of new technologies in the residential building stock that adopt the most efficient available appliance models is estimated using projections from multiple sources. Initial fuel use and performance is estimated based on 2009 Residential Appliance Saturation Study (RASS) survey data.[53] In ComStock, the adoption of new fuel technologies by the commercial building stock is dictated by when a building system (e.g., building envelope, interior/exterior lighting, or HVAC) reaches its end of useful life and requires all technology within that system to be brought up to code.
- **Future Electrification Scenarios** – Electrification projections are drawn from NREL's Electrification Futures Study (EFS) (Mai et al. 2018).[54] Depending on the chosen LA100 scenario, a percentage of new technologies in residential and commercial building stock are switched from fossil fuel-combusting appliances to electric appliances for all new and replacement construction.

Residential and commercial building fuel use is modulated based upon the level of adoption of electric and beyond code appliances.[55] The LA100 study includes two levels of electrification: "Moderate" and "High", where fractions of different appliances are electrified as reported in Table 15. These electrification levels are applied to LA100 scenarios according to the LA100 scenario matrix. For non-electrified appliances, fuel use is determined by the population of appliances operating on natural gas and the efficiency of each appliance. The methods regarding improvements in energy efficiency, the rate of appliance replacement, and the rate of new construction for each building type are common to the Moderate and High scenarios, though the type of appliance and resulting efficiency depends on the selected scenario.[56]

Table 15. Summary of 2045 Electrification Assumptions in the Different End Uses in Commercial and Residential Buildings

	End Use	Moderate Electrification Level	High Electrification Level
Commercial	Water heating	72%	100%
	Space heating	81%	96%
Residential	Water heating	50%	100%
	Space heating	49%	91%
	Dryer	93%	100%
	Cooking	53%	100%

[53] "2019 Residental (sp.) Appliance Saturation Study," CEC, https://www.energy.ca.gov/appliances/rass/.
[54] "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.
[55] Beyond code refers to a code year five years in the future. Moderate and High scenarios both assign all upgrades to be at or beyond code, 20 years ahead for High scenarios, and the Stress projection randomly assigns 20% of upgraded appliances below code, 70% at code, at 10% beyond code.
[56] Note that in the scenario matrix, a "Reference" level of energy efficiency that continues pre-2017 policies is used in the SB100 – Stress scenario, and it exhibits a significant deviation from current goals.

B.3 Methods for Vehicle Fuel Use

The targets for moderate and high levels of vehicle electrification are listed in Table 16. Figure 28 and Figure 29 show adoption scenarios of EVs for 2020 through 2045, representing the total number of vehicles and EV market share, respectively. The data presented in these figures can be found in tabular format in Appendix A.

Table 16. Summary of Electrification Assumptions for Different Light-Duty Vehicles and Buses

	Moderate Electrification	High Electrification
Light-duty vehicles	30% of stock is plug-in electric vehicles (PEV) by 2045	80% of stock is PEV by 2045
School and urban buses	100% by 2030	100% by 2030

- The Moderate and High projections for LDVs (as shown in Figure 28) are each consistent with California's Zero Emission Vehicle (ZEV) goals[57] for 2025 and 2030. The Moderate projection is based on the "high case" EV adoption from the LADWP Strategic Long-Term Resource Plan (SLTRP). This scenario exceeds the California ZEV mandate in 2025 and hits the 2030 ZEV goal (assuming LADWP is responsible for 10% of the EV adoption prescribed in the CA ZEV goal). The High electrification scenario follows the 2017 SLTRP "high case" until 2025, and then assumes more aggressive adoption from 2026 onward based on the NREL's EFS study (Mai et al. 2018). This projection exceeds California ZEV goals and reaches a total EV market share of approximately 80% in 2045. Overall LDV activity increases in all scenarios to reflect expected population growth of the region.

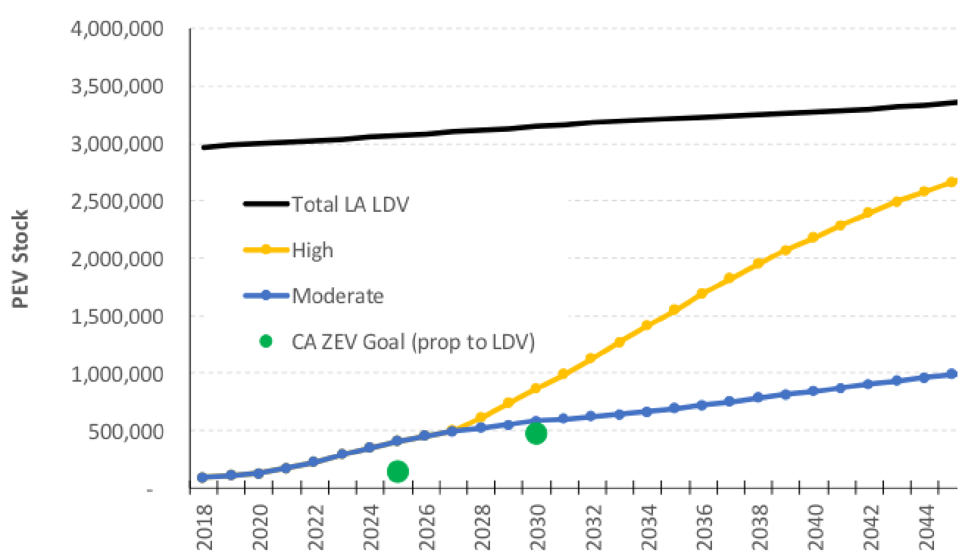

Figure 28. Projections of EV stock (absolute basis), by electrification level

Green markers represent total EV stock goals of the CA ZEV program, proposed for all LDVs.

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[57] "Zero-Emission Vehicle Program," CARB, https://ww2.arb.ca.gov/our-work/programs/zero-emission-vehicle-program/about.

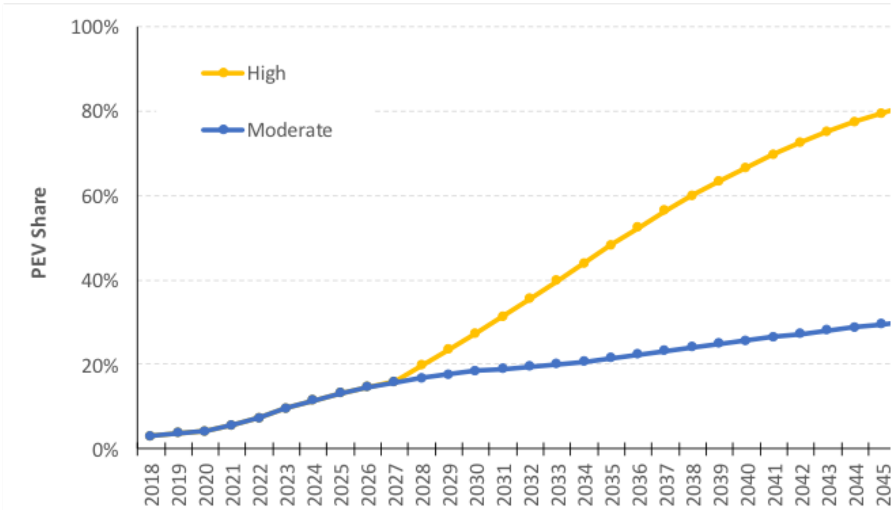

Figure 29. Projections of EV stock as a share of LA light-duty vehicles (percentage basis), by electrification level

The scenarios in the above figures estimate future EV population size for the LADWP service area; the remaining fraction of total vehicles not represented by EVs are primarily powered by petroleum-based fuels.[58] The total estimated number of LDVs for future years and projected EV stock are based on the STLRP and NREL's EFS study, and match the inputs used to calculate GHG emissions from the power sector. The vehicle activity level, measured in vehicle miles traveled (VMT), is extracted for each vehicle type and year from the Emission Factor model (EMFAC) developed by CARB.[59,60] VMT estimates for each vehicle class in EMFAC are based on estimates from regional transportation planning agencies.[61]

GHG emissions from transportation fuel use are the direct result of fuel combustion. Fuel use is not directly output from NREL transportation models but will be estimated in the approach outlined here considering the activity level (VMT), vehicle population and fuel economy for each vehicle type, as well as the GHG emission factor for each fuel and vehicle type. Activity levels are extracted from EMFAC, while fuel economy and emission factors are extracted from the CA-GREET3.0 model. Fuel economy values for each vehicle type are directly reported in the CA-GREET3.0 model and emission factors for each fuel are calculated on a life cycle basis.

Total activity level for electric and conventional fueled vehicles is assumed to increase as the population of vehicles increases. Therefore, the volume of gasoline, diesel, and compressed

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[58] Petroleum based fuels currently account for a majority of the fuel volume used in California. While renewable fuel volumes have been increasing through 2019, current trends indicate that petroleum fuels will retain their majority for years to come ("Low Carbon Fuel Standard Reporting Tool Quarterly Summaries," CARB, last reviewed January 29, 2021, https://ww3.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm).
[59] "Emissions Inventory," CARB, https://arb.ca.gov/emfac/emissions-inventory.
[60] EMFAC also lists the total population for each vehicle type, but for consistency with previous EV adoption modeling by NREL these population values are not used.
[61] CARB, "Appendix T: Proposed LEV III Mobile Source Emissions Inventory: Technical Support Document" (California Air Resources Board, December 7, 2011), https://ww3.arb.ca.gov/msei/onroad/downloads/levappt.pdf.

natural gas (CNG) will change in proportion to the population size of vehicles using each fuel vs. electricity.

Bus electrification is modeled separately from the LDV projections, based on CA law requiring the current fleet of school and transit buses to be 100% electrified by 2030. This assumption applies to all electrification levels (Moderate and High) modeled in LA100. This is a much more rapid electrification scenario compared to LDVs. Electrification fraction of the fleet in any given year reduces the fossil fuel requirements proportionally. The total number of school and metro transit buses is assumed to increase from the baseline number in the LADWP service area, according to EMFAC.[62] Table 17 lists the total number of buses (by bus depot) within the LADWP service area.

Table 17. Summary of Buses by Depot in LADWP Service Territory[a]

Bus Type	Depot	Address	Number of Buses
School Buses	**Gardena Yard**	18421 S Hoover Street Gardena, 90248	404
	Business Division	604 E 15th Street Los Angeles, 90015	400
	Sun Valley Yard	11247 Sherman Way Sun Valley, 91352	200
	Van Nuys Yard	16200 Roscoe Blvd. Van Nuys, 91406	250
	Sepulveda Yard	8920 Sepulveda Blvd. North Hills, 91343	33
	Total		1,287
LA Metro Transit Buses	**Division 1**	1130 E 6th St, Los Angeles, 90021	165
	Division 2	720 E 15th St, Los Angeles, 90021	410
	Division 3	630 W Ave 28, Los Angeles, 90065	178
	Division 5	5425 S Van Ness Ave, Los Angeles, 90062	281
	Division 8	9201 Canoga Ave, Chatsworth, 91311	186
	Division 10	742 N Mission Rd, Los Angeles, 90033	107
	Division 13	920 N Vignes St, Los Angeles, 90012	143
	Division 15	11801-11927 Branford St, Sun Valley, 91352	223
	Total		1,693
LADOT Transit Buses	**Downtown**	454-518 E Commercial St, Los Angeles, 90012	86
	Sylmar	12776 Foothill Blvd, Sylmar, 91342	154
	Washington	1950 East Washington Blvd, Los Angeles, 90021	163
	Total		403

[62] "Fleet Database," CARB, https://arb.ca.gov/emfac/fleet-db

[a] The number of electric buses currently in service is reported by CARB: https://ww2.arb.ca.gov/sites/default/files/2019-10/DWP%20Bus%20Electrification%20Efforts%20Presentation%20-%2010-10-19.pdf

Data on the daily total VMT traveled by school buses was gathered by NREL from the Fleet DNA database for 280 buses in the LA metropolitan area over 1,232 days.[63] These data provide vehicle speed over time as well as the start and end of each weekday shift, which is used to determine an average VMT/day for each bus. Data for LA Metro transit buses was extracted from the developer.metro.net LA Metro Realtime Application Programming Interface (API) to estimate daily VMT for each bus in the service area. Service for LADOT buses is assumed similar to that of LA Metro transit buses.

B.4 Emission Factors for Non-Power Sector Fuels

Emission factors for each of the fuels used in the non-power sector are extracted from CARB's CA-GREET3.0 model, which is a model used in CARB's management of the LCFS program.[64] The CA-GREET3.0 model was adapted from the GREET1 2016 model developed at Argonne National Laboratory and is used to develop life cycle assessment (LCA)-based carbon intensities (CIs) for California's Low Carbon Fuel Standard (LCFS). (In this report, carbon intensity is synonymous with emission factor.) Note that in NREL's use of the CA-GREET3.0 model in the LA100 study, the structure of the model was not altered when calculating emission factors for the required fuels, although several adjustments were made to the default model parameters.

The LCFS mandates a reduction in CI for all transportation fuels through 2030. The LCFS CI targets apply to California Reformulated Gasoline (CaRFG) for gasoline-powered vehicles, and Ultra-Low Sulfur Diesel (ULSD)[65] for diesel-powered vehicles (which are themselves blends of constituent fuels), as well as their replacements. Thus, the required CIs for each fuel category do not apply to specific fuels directly; rather, the mandate applies to the pool of vehicles that would otherwise run on CaRFG or ULSD. Since there is no requirement that the CI reduction be the result of changes in a specific fuel's CI, emission factors for CaRFG and ULSD do not directly correspond to requirements of the LCFS,[66] though they do follow the same decreasing trend until 2030. The LCFS mandate for fuel CI does not list specific targets beyond 2030, so while CI may continue to decrease, these values are held constant for this analysis since there are no requirements for specific changes.

Each fuel is a blend of fossil fuels and renewable fuels, except where noted. Additional information regarding inputs for each fuel included in the non-power sector is given below:

- **CaRFG**: This fuel is used in light-duty vehicles and school buses (28%-43% for buses depending on the year, according to EMFAC), and represents a finished gasoline product which is blended from two ingredients: California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)

[63] "Fleet DNA: Commercial Fleet Vehicle Operating Data," NREL, www.nrel.gov/fleetdna.
[64] "CA-GREET3.0 Model and Tier 1 Simplified Carbon Intensity Calculators," CARB, https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.
[65] "Low Carbon Fuel Standard," CARB, https://ww2.arb.ca.gov/sites/default/files/2020-06/basics-notes_1.pdf.
[66] For instance, the replacement of a light-duty gasoline vehicle with a light-duty ZEV would lower the CI for gasoline and its replacements, because the ZEV is a vehicle that would otherwise run on gasoline. The CI for gasoline itself is not affected by the vehicle replacement.

and ethanol. The CA-GREET3.0 model states that CARBOB cannot be used in vehicles directly, so this fuel blendstock is blended with ethanol to meet a nominal 2% (by weight) oxygen requirement for finished gasoline sold and used in California. Data listing the volumes and CI for all fuels is reported quarterly to the LCFS, including CARBOB and ethanol. No renewable gasoline is included in the current LCFS quarterly reporting data and thus is not considered in LA100, even though it is possible that in future years some could be introduced into the market.

- **ULSD**: Within the scope of LA100, this fuel is used in just in school buses and represents a finished diesel product used in California.[67] LCFS quarterly reporting data shows that petroleum-sourced diesel accounts for the majority of ULSD consumed, though the final emission factor used in the LA100 GHG analysis considers the small fraction of bio-diesel and renewable diesel reported to CARB.[68] The CI for ULSD in LA100 is a weighted average of petroleum-based ULSD, bio-diesel, and renewable diesel, weighted based on 2019 volumes reported to LCFS and explained in further detail below.
- **CNG**: Within the scope of this analysis, CNG as a transport fuel is used exclusively by urban buses. EMFAC lists natural gas as a common fuel for urban buses, and CNG represents the primary fuel used for urban buses in the LADWP service area.[69] CNG is natural gas that has been highly compressed for use in vehicles. The use of both fossil-based and renewable-sourced CNG is addressed in the quarterly LCFS reporting data, and further described below.
- **Natural Gas**: Natural gas is used for heating and cooking within residential and commercial buildings. As natural gas does not require compression or liquefaction to a liquid state when it is used for residential or commercial purposes, the CI for this fuel represents its use in a continually gaseous state following production.[70] Natural gas is assumed to be entirely fossil-fuel sourced fuel because there is no mandate for renewable content and no reporting of its historical use to-date.

Emission factors for each of these fuels are split into several life cycle stages when calculating GHG emissions.[71] The four life cycle stages required to capture all relevant GHG emissions from power generation (as detailed in Appendix A) are adjusted herein to account for GHG emissions from fuels in the non-power sector. The primary difference in life cycle stages applies to one-time upstream and downstream emissions, which, as stated above, are not considered in

[67] Diesel is used only in school buses within the scope of LA100. There is some minor use of diesel in LDVs that is not included due to the low percentage of use.
[68] Renewable diesel is a direct diesel replacement, while bio-diesel is an ester that must be blended with diesel before use in a vehicle ("Renewable Hydrocarbon Biofuels," DOE, https://afdc.energy.gov/fuels/emerging_hydrocarbon.html).
[69] "Los Angeles Metro," SoCalGas," https://www.socalgas.com/for-your-business/natural-gas-vehicles/Metro.
[70] Natural gas does undergo compression before entering a natural gas pipeline, which represents pressurization of the gas for transportation. The compression stage of CNG for fuel use represents compression of the gas to a liquid at a refueling station, which is more energy-intensive than the pressurization required for pipeline transport.
[71] The life cycle stages used for the non-power sector display some overlap with the analysis methods for GHG emissions from the power sector, which categorized a generator's GHG emissions into four stages:

- *One-time upstream emissions* – construction of the generator
- *Ongoing non-combustion operational emissions* – non-combustion activities from operation of the generator
- *Ongoing combustion emissions* – combustion emissions and those associated with direct power generation
- *One-time downstream emissions* – decommissioning of the generator

Ongoing power sector GHG emissions were estimated by applying generator-specific emissions factors to output of fuel burn from PLEXOS modeling, while results of NREL's LCA Harmonization project ("Life Cycle Assessment Harmonization," NREL, https://www.nrel.gov/analysis/life-cycle-assessment.html) were applied to reported generator capacities to estimate the GHG emissions from the one-time upstream and one-time downstream stages.

the analysis of GHG emissions from non-power sector. Instead, we only consider the fuel cycle (including fuel combustion) portion of total life cycle emissions.

For natural gas used in building appliances, the fuel life cycle begins with extraction and processing of the raw materials used to produce the fuel, including well construction and operation, and ends with combustion within a stationary source in each building. For transportation fuels, the analogous life cycle is commonly referred to as the “well-to-wheel” system boundary, since the GHG emissions begin with extraction at a petroleum or a natural gas well and end when combusted to propel a vehicle. A similar scope applies for biofuels (without a literal well), with a scope beginning at feedstock production and processing and ending with combustion in a vehicle.

There are two life cycle stages included for non-power sector fuels, with a description of how the GHG emissions were considered from each fuel:

- **Fuel cycle GHG emissions:** This stage includes all emissions associated with feedstock extraction/production, processing, and transport of a fuel to its final destination (such as a fueling station or stationary combustion source).
    - For petroleum-derived fuels, the steps of crude (or gas) extraction and transportation, refining, and distribution of the refined product to a fueling station are all included.
    - For ethanol, all emissions from production of ethanol (blended with CARBOB to yield CaRFG) are considered, yet combustion of biogenic ethanol (in CaRFG) creates biogenic CO_2 that does not count toward the CI for the fuel.[72]
    - For bio-diesel and renewable diesel, the steps of waste collection and processing, farming, fertilizer use, feedstock processing, soil nitrogen release, fuel and electricity use for fuel production, land use change, distribution, and any applicable co-product credits are all included. Emissions from each step are included depending on the selected fuel pathway, since alternative diesel fuel production can include either waste-sourced or crop-sourced feedstocks.
    - For fossil-based natural gas, the steps of natural gas extraction, processing, transport to a refueling station, and any necessary compression or liquefaction are all included in the scope of this analysis. CNG includes these steps plus compression.
    - For renewable natural gas (RNG), the steps of capture from a renewable source, processing, transport, distribution, and compression to CNG are all included. RNG is currently only used for the production of CNG (see Limitations and Caveats).
    - For each fuel type, emissions and energy use from well drilling and pipeline construction are included in the analysis (where applicable) and distributed amongst each unit of fuel produced.
- **Fuel Combustion GHG emissions:** This stage includes emissions from combustion of a fuel in a mobile or stationary source.

[72] Biogenic CO_2 is part of the natural carbon cycle and is replenished when new biomass is produced. The EPA considers the release of biogenic CO_2 to be carbon neutral (Pruitt, 2018).

- Combustion emissions from ethanol, renewable diesel, bio-diesel, and RNG combustion emissions are represented by CH_4 and N_2O only. The CO_2 produced from combustion of these fuels is biogenic and therefore excluded from the CI.
- The final emission factors reported for each fuel are an average of those for renewable and fossil-based fuels, weighted by energy content.

Given the blending of different input fuels to achieve final fuel blends used by consumers, we report here the method we use for averaging the component fuel's CIs to achieve a final fuel CI. For CARBOB, fossil-sourced ULSD, and CNG, the tank-to-wheel CIs listed in 'Petroleum' and 'NG' tabs of the CA-GREET3.0 model are used. For natural gas consumed in buildings, combustion CIs for several stationary sources were obtained from the 'EF' tab of the CA-GREET3.0 model.[73]

- **CaRFG**: the CIs for CARBOB and ethanol are extracted from the CA-GREET3.0 model for all years of the study. The apportionment between CARBOB and ethanol is based on the 2% (by weight) oxygen requirement in finished gasoline, which is approximately 6.96% ethanol by energy content. An energy-content weighted-average CI is calculated for CaRFG from each year 2020 to 2045.
- **ULSD**: the CIs for fossil-sourced ULSD, biodiesel, and renewable diesel are extracted from the CA-GREET3.0 model for all years of the study. The apportionment between fossil ULSD, biodiesel, and renewable diesel is based on the volumes reported in 2019 LCFS quarterly data and, lacking any projection provided by CARB, held constant for all future years. The volume fractions for each type of diesel are used to create a weighted average on an energy basis, using the heating value for each fuel.
- **CNG**: the CI for fossil-sourced CNG and RNG were extracted from the CA-GREET3.0 model for all years of the study. The apportionment between fossil CNG and RNG is based on the volumes reported in 2019 LCFS quarterly data and, lacking any projection provided by CARB, held constant for all future years. (Note that CNG is an alternative fuel to ULSD for buses, and there is no mandate for the future CI of this fuel.) CNG and RNG have similar energy density, so averaging volumetrically is equivalent to an energy-based weighted-average.
- **Natural Gas**: Natural gas used in buildings required no averaging to calculate the final CI since this is solely a fossil-sourced fuel.

The final CIs for all fuels are listed in Table 18. These values represent input from both renewable and fossil fuels and are based on the output of the CA-GREET3.0 model for years 2018 – 2045.[74] CNG emission factors extend only through 2030 due to 100% bus electrification in that year, removing the only source of CNG consumption. Annual CIs for each fuel by life cycle stage can be found in Table 19 through Table 22.

[73] The CI for "Small Industrial Boiler, 10-100 MMBtu/hr" is used for direct natural gas combustion under the assumption that building heating is the most common natural gas use for building stock.
[74] CA-GREET3.0 inputs are for years 2018-2040, where CIs for 2041-2045 are assumed to be equal to CIs in 2040. See Limitations and Caveats for additional detail.

Table 18. Total GHG Carbon Intensities for Stationary and Mobile Fuels

Note: All values are in grams of carbon dioxide equivalent per megajoule (g CO_2e / MJ). CNG is not applicable (N/A) after 2030 because by then all buses must be electrified.

Year	CaRFG	ULSD	CNG	Natural Gas
2019	99.56	90.52	63.03	74.87
2020	99.34	90.29	59.51	74.87
2021	99.34	90.29	59.51	74.83
2022	99.34	90.29	59.51	74.83
2023	99.34	90.29	59.51	74.83
2024	99.34	90.29	59.51	74.83
2025	99.21	90.15	56.95	74.83
2026	99.21	90.15	56.95	74.80
2027	99.21	90.15	56.95	74.80
2028	99.21	90.15	56.95	74.80
2029	99.21	90.15	56.95	74.80
2030	99.19	90.12	56.54	74.80
2031	99.19	90.12	N/A	74.80
2032	99.19	90.12	N/A	74.80
2033	99.19	90.12	N/A	74.80
2034	99.19	90.12	N/A	74.80
2035	99.12	90.05	N/A	74.80
2036	99.12	90.05	N/A	74.78
2037	99.12	90.05	N/A	74.78
2038	99.12	90.05	N/A	74.78
2039	99.12	90.05	N/A	74.78
2040	99.09	90.01	N/A	74.78
2041	99.09	90.01	N/A	74.77
2042	99.09	90.01	N/A	74.77
2043	99.09	90.01	N/A	74.77
2044	99.09	90.01	N/A	74.77
2045	99.09	90.01	N/A	74.77

Total GHG emissions are based on the product of the activity factor (A) and CI (B) for each source type and fuel. Total GHG emissions for a selected year (F) are determined with one of the following equations, depending on the end use of each fuel:

(Building GHG Emissions) $$F = A \times B \times C$$

(CaRFG / ULSD GHG Emissions) $$F = {(A \times B \times E)}/{D}$$

(CNG GHG Emissions) $$F = A \times B \times G$$

CIs (B) are in units of g CO_2e / MJ and are extracted from the CA-GREET3.0 model. Activity factors (A) are an output of the ResStock and ComStock models for natural gas in buildings, and EMFAC for CaRFG, ULSD, and CNG. Activity factors are provided in units of therms for building energy use and VMT for vehicle fuels. Building energy use is converted to MJ with the unit conversion (C) of 1 therm = 105.48 MJ.

Vehicle emissions also rely on the fuel efficiency in miles per gallon (mpg) (D), which is reported for each vehicle type and fuel in CA-GREET3.0. The transit bus CNG fuel efficiency, in BTU / mile (G), is listed separately from LDV fuel efficiency in the CA-GREET3.0 model. The heating value (E) for CaRFG and ULSD is the lower heating value (LHV) as reported in the CA-GREET3.0 model, provided in units of MJ per gallon.[75]

Vehicle activity factors are calculated for each model year. CaRFG and ULSD LHV, as well as CNG fuel efficiency, are fixed values in CA-GREET3.0 and do not change. Fuel efficiency values for CaRFG and ULSD vehicles change every five years within CA-GREET3.0. Variables (B), (D), (G), and (E) are extracted from the CA-GREET3.0 model, while (A) depends on the output of ResStock, ComStock, or EMFAC.

[75] The default option within the CA-GREET3.0 model uses the LHV for each fuel. Using the higher heating value (HHV) for each fuel would require adjustment of the combustion emission factors and is not recommended here, as the water within the exhaust is not typically condensed following combustion of the listed fuels.

Table 19. Buildings Sector GHG Emissions Factors for Natural Gas Consumption, by Year and Life Cycle Stage

These apply to both residential and commercial building types and were derived from the CA-GREET v. 3.0 model.

Year	Combustion ($g\ CO_2e$ / therm)	Fuel Cycle ($g\ CO_2e$ / therm)	Total ($g\ CO_2e$ / therm)
2020	5953	1687	7640
2021	5953	1687	7640
2022	5953	1687	7640
2023	5953	1687	7640
2024	5953	1687	7640
2025	5953	1684	7638
2026	5953	1684	7638
2027	5953	1684	7638
2028	5953	1684	7638
2029	5953	1684	7638
2030	5953	1684	7637
2031	5953	1684	7637
2032	5953	1684	7637
2033	5953	1684	7637
2034	5953	1684	7637
2035	5953	1683	7636
2036	5953	1683	7636
2037	5953	1683	7636
2038	5953	1683	7636
2039	5953	1683	7636
2040	5953	1682	7635
2041	5953	1682	7635
2042	5953	1682	7635
2043	5953	1682	7635
2044	5953	1682	7635
2045	5953	1682	7635

Table 20. Vehicle Sector GHG Emissions Factors for Gasoline Consumption, by Year, Life Cycle Stage, and Vehicle Type

Values in grams of carbon dioxide equivalent per vehicle mile traveled (g CO_2e/VMT)

	Cars			Light-duty Trucks Type 1[76]			Light-duty Trucks Type 2[77]			School Bus			Urban Bus		
Year	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**
2020–2024	266	118	384	363	161	524	441	195	636	1004	444	1448	1871	828	2699
2025–2029	239	105	344	341	150	492	416	183	599	1004	442	1446	1871	825	2695
2030–2034	226	99	325	331	146	476	403	177	580	1004	442	1446	1871	824	2695
2035–2039	211	93	304	297	130	427	348	153	500	1004	441	1445	1871	822	2693
2040–2045	211	93	304	297	130	427	348	153	500	1004	441	1444	1871	821	2692

Table 21. Vehicle Sector GHG Emissions Factors for Diesel Consumption, by Year, Life Cycle Stage, and Vehicle Type

Values in grams of carbon dioxide equivalent per vehicle mile traveled (g CO_2e/VMT)

	Cars			Light-duty Trucks Type 1[14]			Light-duty Trucks Type 2[15]			School Bus			Urban Bus		
Year	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**	**Combustion**	**Fuel Cycle**	**Total**
2020–2024	230	121	351	292	153	445	348	183	531	971	509	1481	1810	949	2759
2025–2029	209	109	318	273	143	416	327	171	497	971	507	1478	1810	945	2755
2030–2034	195	102	297	264	137	401	317	165	482	971	507	1478	1810	944	2754
2035–2039	179	93	271	250	130	380	287	149	436	971	505	1477	1810	942	2752
2040–2045	179	93	271	250	130	379	287	149	436	971	505	1476	1810	941	2751

[76] Gross Vehicle Weight Rating < 6,000 lbs. and Equivalent Test Weight ≤ 3,750 lbs
[77] Gross Vehicle Weight Rating < 6,000 lbs. and Equivalent Test Weight 3,751−5,750 lbs

Table 22. Vehicle Sector GHG Emissions Factors for Compressed Natural Gas and Propane Consumption, by Year, Life Cycle Stage, and Bus Type

Values in grams of carbon dioxide equivalent per vehicle mile traveled (g CO_2e/VMT)

	Compressed Natural Gas (CNG)						Propane[78]		
	School Bus			Urban Bus			School Bus		
Year	Combustion	Fuel Cycle	Total	Combustion	Fuel Cycle	Total	Combustion	Fuel Cycle	Total
2020–2024	921	446	1366	1669	809	2478	834	266	1100
2025–2029	862	446	1308	1563	809	2371	835	263	1098
2030[79]	852	446	1298	1563	809	2371	835	263	1098

[78] Propane fuel does not apply to urban buses.
[79] Urban and school bus fleets are assumed to be 100% electric after 2030.

Appendix C. Tabulations of Results for Power Sector

Table 23. Cumulative (2020–2045) Combustion and Life Cycle GHG Emissions for LA100 Scenarios, by Load Projection

LA100 Scenario	Load Projection	Cumulative Combustion GHGs (MMT CO_2e)	Cumulative Life Cycle GHGs (MMT CO_2e)
SB100	Moderate	84.7	123.7
	High	97.6	141.4
	Stress	105.8	153.4
Early & No Biofuels	Moderate	32.4	65.3
	High	32.8	68.9
Transmission Focus	Moderate	55.3	92.7
	High	59.9	102.4
Limited New Transmission	Moderate	57.0	95.1
	High	56.2	97.9

Table 24. Annual Combustion GHG Emissions for Scenarios, by Load Projection and Year

LA100 Scenario	Load Projection	2020	2025	2030	2035	2040	2045
2017 IRP	Moderate	11.10	5.27	2.55	2.79	N/A	N/A
SB100	Moderate	11.10	5.49	2.13	1.33	1.51	1.86
	High	11.10	5.34	2.26	2.56	2.45	2.73
	Stress	11.10	6.14	2.67	2.65	2.62	3.07
Early & No Biofuels	Moderate	11.10	0.86	0.07	0.00	0.00	0.00
	High	11.10	0.89	0.11	0.00	0.00	0.00
Transmission Focus	Moderate	11.10	1.96	0.92	1.27	1.36	0.00
	High	11.10	1.86	0.87	1.75	1.93	0.00
Limited New Transmission	Moderate	11.10	2.32	0.87	1.18	1.49	0.00
	High	11.10	1.83	0.82	1.11	1.92	0.00

Table 25. Annual Life Cycle GHG Emissions for Scenarios, by Load Projection and Year

LA100 Scenario	Load Projection	2020	2025	2030	2035	2040	2045
2017 IRP	Moderate	12.80	7.36	4.04	4.27	N/A	N/A
SB100	Moderate	12.80	7.60	3.66	2.54	2.57	2.89
	High	12.80	7.37	3.87	4.17	3.83	4.09
	Stress	12.80	8.32	4.50	4.42	4.09	4.62
Early & No Biofuels	Moderate	12.80	3.04	1.52	0.75	0.58	0.58
	High	12.80	3.01	1.63	0.95	0.76	0.85
Transmission Focus	Moderate	12.80	4.10	1.93	2.21	2.32	1.40
	High	12.80	3.95	2.06	2.97	3.22	1.73
Limited New Transmission	Moderate	12.80	4.51	2.05	2.17	2.45	1.25
	High	12.80	3.94	2.08	2.34	3.23	1.41

Appendix D. Tabulations of Results for Buildings Sector

Table 26. Cumulative (2020–2045) Life Cycle GHG Emissions for Residential and Commercial Buildings, by Load Projection and Building Type

Load Projection	Building Sector	Cumulative Life Cycle GHGs (MMT CO_2e)
Moderate	Residential	56.03
Moderate	Commercial	67.35
High	Residential	33.83
High	Commercial	40.05
Stress	Residential	37.26
Stress	Commercial	43.87

Table 27. Annual and Cumulative (2020–245) Life Cycle GHG Emissions for Residential Buildings, by Load Projection and Year

Load Projection →	Moderate		High		Stress	
Year	Annual Life Cycle GHG (MMT CO_2e/year)	Cumulative Life Cycle GHG (MMT CO_2e)	Annual Life Cycle GHG (MMT CO_2e/year)	Cumulative Life Cycle GHG (MMT CO_2e)	Annual Life Cycle GHG (MMT CO_2e/year)	Cumulative Life Cycle GHG (MMT CO_2e)
2020	2.26	2.26	2.26	2.26	2.26	2.26
2021	2.27	4.53	2.21	4.47	2.26	4.52
2022	2.28	6.81	2.16	6.63	2.25	6.77
2023	2.28	9.09	2.10	8.73	2.25	9.02
2024	2.29	11.38	2.05	10.78	2.24	11.26
2025	2.30	13.67	2.00	12.78	2.24	13.50
2026	2.28	15.95	1.92	14.70	2.15	15.66
2027	2.26	18.22	1.85	16.55	2.07	17.72
2028	2.25	20.47	1.78	18.33	1.98	19.71
2029	2.23	22.70	1.70	20.04	1.90	21.60
2030	2.22	24.92	1.63	21.67	1.81	23.41
2031	2.22	27.14	1.51	23.18	1.70	25.11
2032	2.21	29.35	1.39	24.57	1.59	26.70
2033	2.21	31.56	1.27	25.85	1.47	28.17
2034	2.21	33.77	1.16	27.00	1.36	29.54
2035	2.21	35.98	1.04	28.04	1.25	30.79
2036	2.18	38.17	0.94	28.98	1.12	31.91
2037	2.16	40.32	0.84	29.82	0.99	32.90
2038	2.13	42.46	0.74	30.56	0.86	33.75
2039	2.11	44.56	0.65	31.21	0.73	34.48
2040	2.08	46.64	0.55	31.76	0.60	35.08
2041	2.01	48.65	0.50	32.26	0.54	35.62
2042	1.95	50.60	0.46	32.72	0.49	36.11
2043	1.88	52.48	0.41	33.13	0.44	36.55
2044	1.81	54.29	0.37	33.50	0.38	36.93
2045	1.74	56.03	0.32	33.83	0.33	37.26

Table 28. Annual and Cumulative (2020–2045) Life Cycle GHG Emissions for Commercial Buildings, by Load Projection and Year

Load Projection →	Moderate		High		Stress	
Year	Annual Life Cycle GHG (MMT CO_2e/year)	Cumulative Life Cycle GHG (MMT CO_2e)	Annual Life Cycle GHG (MMT CO_2e/year)	Cumulative Life Cycle GHG (MMT CO_2e)	Annual Life Cycle GHG (MMT CO_2e/year)	Cumulative Life Cycle GHG (MMT CO_2e)
2020	2.64	2.64	2.64	2.64	2.64	2.64
2021	2.65	5.29	2.59	5.22	2.63	5.27
2022	2.65	7.94	2.53	7.76	2.63	7.90
2023	2.66	10.60	2.48	10.23	2.62	10.52
2024	2.67	13.27	2.42	12.65	2.62	13.14
2025	2.68	15.95	2.37	15.02	2.61	15.75
2026	2.68	18.62	2.28	17.30	2.53	18.27
2027	2.68	21.30	2.20	19.50	2.45	20.72
2028	2.68	23.99	2.11	21.61	2.37	23.09
2029	2.68	26.67	2.03	23.64	2.28	25.37
2030	2.69	29.36	1.94	25.58	2.20	27.57
2031	2.68	32.04	1.81	27.39	2.06	29.63
2032	2.68	34.71	1.68	29.07	1.91	31.54
2033	2.67	37.38	1.55	30.62	1.76	33.30
2034	2.66	40.05	1.41	32.03	1.61	34.91
2035	2.66	42.71	1.28	33.31	1.46	36.37
2036	2.63	45.34	1.15	34.46	1.31	37.69
2037	2.60	47.94	1.02	35.49	1.16	38.85
2038	2.57	50.51	0.89	36.38	1.01	39.86
2039	2.54	53.05	0.76	37.14	0.86	40.72
2040	2.52	55.57	0.63	37.77	0.71	41.43
2041	2.46	58.03	0.57	38.35	0.63	42.06
2042	2.41	60.44	0.51	38.86	0.56	42.62
2043	2.36	62.79	0.45	39.32	0.49	43.11
2044	2.30	65.10	0.40	39.71	0.41	43.53
2045	2.25	67.35	0.34	40.05	0.34	43.87

Table 29. Cumulative (2020–2045) GHG Emissions by Load Projection, Life Cycle Stage and Building Type

Load Projection	Life Cycle Stage	Residential Life Cycle GHG (MMT CO_2e)	Commercial Life Cycle GHG (MMT CO_2e)
Moderate	Combustion	43.68	52.50
Moderate	Fuel Cycle	12.35	14.85
High	Combustion	26.37	31.21
High	Fuel Cycle	7.46	8.83
Stress	Combustion	29.04	34.19
Stress	Fuel Cycle	8.22	9.68

Appendix E. Tabulations of Results for Vehicle Sector

Table 30. Annual and Cumulative (2020–2045) Life Cycle GHG Emissions for Light-Duty Vehicles and Buses, by EV Adoption Scenario and Year

EV Adoption Scenario →	Moderate		High	
Year	Annual Life Cycle GHG (MMT CO_2e /year)	Cumulative Life Cycle GHG (MMT CO_2e)	Annual Life Cycle GHG (MMT CO_2e /year)	Cumulative Life Cycle GHG (MMT CO_2e)
2020	17.77	17.77	17.77	17.77
2021	17.37	35.14	17.37	35.14
2022	16.91	52.05	16.91	52.05
2023	16.36	68.41	16.36	68.41
2024	15.89	84.30	15.89	84.30
2025	14.15	98.44	14.15	98.44
2026	13.79	112.23	13.79	112.23
2027	13.50	125.73	13.48	125.71
2028	13.28	139.01	12.80	138.51
2029	13.06	152.06	12.12	150.63
2030	12.29	164.35	10.94	161.57
2031	12.16	176.51	10.31	171.88
2032	12.03	188.54	9.65	181.53
2033	11.91	200.45	8.97	190.50
2034	11.78	212.23	8.31	198.81
2035	10.51	222.74	6.93	205.74
2036	10.36	233.10	6.35	212.09
2037	10.22	243.32	5.81	217.90
2038	10.08	253.40	5.30	223.20
2039	9.95	263.36	4.85	228.05
2040	9.83	273.19	4.43	232.48
2041	9.71	282.90	4.01	236.49
2042	9.60	292.50	3.63	240.12
2043	9.50	302.00	3.29	243.41
2044	9.40	311.40	2.99	246.40
2045	9.31	320.71	2.71	249.11

Table 31. Cumulative (2020–2045) Life Cycle GHG Emissions for Light-Duty Vehicles and Buses, by EV Adoption Scenario Life Cycle Stage

EV Adoption Scenario	Life Cycle Stage	Cumulative (2020–2045) GHG Emissions (MMT CO_2e)
Moderate	Combustion	222.50
Moderate	Fuel Cycle	98.21
High	Combustion	172.77
High	Fuel Cycle	76.33

Table 32. Annual Life Cycle GHG Emissions, by Vehicle Type, EV Adoption Scenario, and Year

EV Adoption Scenario →	Moderate					High				
Vehicle Type →	LDA	LDT1	LDT2	SBUS	UBUS	LDA	LDT1	LDT2	SBUS	UBUS
Year										
2020	10.30	1.51	5.76	0.03	0.18	10.30	1.51	5.76	0.03	0.18
2021	10.02	1.51	5.66	0.03	0.16	10.02	1.51	5.66	0.03	0.16
2022	9.71	1.49	5.54	0.03	0.14	9.71	1.49	5.54	0.03	0.14
2023	9.35	1.47	5.39	0.02	0.12	9.35	1.47	5.39	0.02	0.12
2024	9.04	1.45	5.27	0.02	0.11	9.04	1.45	5.27	0.02	0.11
2025	7.84	1.34	4.86	0.02	0.08	7.84	1.34	4.86	0.02	0.08
2026	7.61	1.33	4.77	0.01	0.07	7.61	1.33	4.77	0.01	0.07
2027	7.43	1.32	4.70	0.01	0.05	7.42	1.31	4.69	0.01	0.05
2028	7.28	1.31	4.65	0.01	0.03	7.02	1.26	4.48	0.01	0.03
2029	7.14	1.30	4.60	< 0.01	0.02	6.63	1.20	4.26	< 0.01	0.02
2030	6.63	1.25	4.40	0.00	0.00	5.91	1.11	3.92	0.00	0.00
2031	6.55	1.24	4.37	0.00	0.00	5.55	1.05	3.70	0.00	0.00
2032	6.46	1.24	4.34	0.00	0.00	5.18	0.99	3.48	0.00	0.00
2033	6.38	1.23	4.30	0.00	0.00	4.80	0.93	3.24	0.00	0.00
2034	6.30	1.22	4.26	0.00	0.00	4.44	0.86	3.01	0.00	0.00
2035	5.79	1.09	3.63	0.00	0.00	3.82	0.72	2.39	0.00	0.00
2036	5.70	1.08	3.58	0.00	0.00	3.49	0.66	2.20	0.00	0.00
2037	5.61	1.07	3.54	0.00	0.00	3.19	0.61	2.01	0.00	0.00
2038	5.53	1.06	3.49	0.00	0.00	2.91	0.56	1.84	0.00	0.00
2039	5.46	1.05	3.45	0.00	0.00	2.66	0.51	1.68	0.00	0.00
2040	5.39	1.04	3.41	0.00	0.00	2.43	0.47	1.54	0.00	0.00
2041	5.32	1.03	3.37	0.00	0.00	2.20	0.42	1.39	0.00	0.00
2042	5.25	1.02	3.33	0.00	0.00	1.99	0.38	1.26	0.00	0.00
2043	5.20	1.01	3.29	0.00	0.00	1.80	0.35	1.14	0.00	0.00
2044	5.14	1.00	3.26	0.00	0.00	1.63	0.32	1.04	0.00	0.00
2045	5.09	0.99	3.23	0.00	0.00	1.48	0.29	0.94	0.00	0.00

LDA = Passenger Car; SBUS = School bus; UBUS = Urban bus
LDT1 = Light-duty Truck Type 1 - Gross Vehicle Weight Rating < 6,000 lbs. and Equivalent Test Weight ≤ 3,750 lbs
LDT2 = Light-duty Truck Type 2 - Gross Vehicle Weight Rating < 6,000 lbs. and Equivalent Test Weight 3,751−5,750 lbs

Appendix F. Further Monetization Results

Comparison of costs between GHG scenarios can, to an extent, mitigate some uncertainty in estimates of the value of future emissions because the same valuation methodology is applied to different emissions trajectories. Table 33 provides a summary of total costs under each scenario while Table 34 through Table 36 show differences between these scenarios.

Positive differences between each scenario represent a benefit while negative differences reflect a cost.

Data in Table 34 through Table 36 show the scenario indicated in the column head subtracted from the scenario in the row head. In Table 34, for example, Limited New Transmission – Moderate less Early & No Biofuels – Moderate is $0.8 billion.

Table 33. Total Life Cycle Cost Under Each Scenario

	Moderate				High				Stress
	Limited New Transmission	Early & No Biofuels	SB100	Transmission Focus	Limited New Transmission	Early & No Biofuels	SB100	Transmission Focus	SB100
5%	$15.1	$14.3	$15.9	$15.0	$11.8	$11.0	$13.0	$11.9	$13.6
3%	$42.0	$39.7	$44.2	$41.8	$32.8	$30.7	$36.1	$33.1	$37.7
2.50%	$58.5	$55.2	$61.4	$58.1	$45.6	$42.6	$50.3	$46.1	$52.5

Table 34. Comparison of Monetized Life Cycle Totals at a 5% Discount Rate ($ Billions 2019)

		Moderate				High				Stress
		Limited New Transmission	Early & No Biofuels	SB100	Transmission Focus	Limited New Transmission	Early & No Biofuels	SB100	Transmission Focus	SB100
Moderate	**Limited New Transmission**	$0.0	-$0.8	$0.8	-$0.1	-$3.3	-$4.1	-$2.1	-$3.2	-$1.6
	Early & No Biofuels	$0.8	$0.0	$1.6	$0.7	-$2.5	-$3.3	-$1.3	-$2.4	-$0.7
	SB100	-$0.8	-$1.6	$0.0	-$0.9	-$4.1	-$4.9	-$2.9	-$4.0	-$2.3
	Transmission Focus	$0.1	-$0.7	$0.9	$0.0	-$3.2	-$4.0	-$2.0	-$3.1	-$1.5
High	**Limited New Transmission**	$3.3	$2.5	$4.1	$3.2	$0.0	-$0.8	$1.2	$0.1	$1.8
	Early & No Biofuels	$4.1	$3.3	$4.9	$4.0	$0.8	$0.0	$2.0	$0.9	$2.5
	SB100	$2.1	$1.3	$2.9	$2.0	-$1.2	-$2.0	$0.0	-$1.1	$0.6
	Transmission Focus	$3.2	$2.4	$4.0	$3.1	-$0.1	-$0.9	$1.1	$0.0	$1.7
Stress	**SB100**	$1.6	$0.7	$2.3	$1.5	-$1.8	-$2.5	-$0.6	-$1.7	$0.0

Table 35. Comparison of Monetized Life Cycle Totals at a 3% Discount Rate (21019$ Billions)

		Moderate				High				Stress
		Limited New Transmission	Early & No Biofuels	SB100	Transmission Focus	Limited New Transmission	Early & No Biofuels	SB100	Transmission Focus	SB100
Moderate	Limited New Transmission	$0.0	-$2.3	$2.1	-$0.2	-$9.2	-$11.4	-$5.9	-$8.9	-$4.3
	Early & No Biofuels	$2.3	$0.0	$4.4	$2.1	-$6.9	-$9.1	-$3.6	-$6.6	-$2.0
	SB100	-$2.1	-$4.4	$0.0	-$2.4	-$11.3	-$13.5	-$8.0	-$11.0	-$6.4
	Transmission Focus	$0.2	-$2.1	$2.4	$0.0	-$9.0	-$11.1	-$5.6	-$8.7	-$4.1
High	Limited New Transmission	$9.2	$6.9	$11.3	$9.0	$0.0	-$2.2	$3.3	$0.3	$4.9
	Early & No Biofuels	$11.4	$9.1	$13.5	$11.1	$2.2	$0.0	$5.5	$2.5	$7.1
	SB100	$5.9	$3.6	$8.0	$5.6	-$3.3	-$5.5	$0.0	-$3.0	$1.6
	Transmission Focus	$8.9	$6.6	$11.0	$8.7	-$0.3	-$2.5	$3.0	$0.0	$4.6
Stress	SB100	$4.3	$2.0	$6.4	$4.1	-$4.9	-$7.1	-$1.6	-$4.6	$0.0

Table 36. Comparison of Monetized Life Cycle Totals at a 5% Discount Rate (2019$ Billions)

		Moderate				High				Stress
		Limited New Transmission	**Early & No Biofuels**	**SB100**	**Transmission Focus**	**Limited New Transmission**	**Early & No Biofuels**	**SB100**	**Transmission Focus**	**SB100**
Moderate	**Limited New Transmission**	$0.0	-$3.2	$3.0	-$0.3	-$12.8	-$15.8	-$8.2	-$12.4	-$6.0
	Early & No Biofuels	$3.2	$0.0	$6.2	$2.9	-$9.6	-$12.6	-$5.0	-$9.2	-$2.8
	SB100	-$3.0	-$6.2	$0.0	-$3.3	-$15.8	-$18.8	-$11.1	-$15.4	-$9.0
	Transmission Focus	$0.3	-$2.9	$3.3	$0.0	-$12.5	-$15.5	-$7.8	-$12.1	-$5.7
High	**Limited New Transmission**	$12.8	$9.6	$15.8	$12.5	$0.0	-$3.0	$4.6	$0.4	$6.8
	Early & No Biofuels	$15.8	$12.6	$18.8	$15.5	$3.0	$0.0	$7.6	$3.4	$9.8
	SB100	$8.2	$5.0	$11.1	$7.8	-$4.6	-$7.6	$0.0	-$4.2	$2.2
	Transmission Focus	$12.4	$9.2	$15.4	$12.1	-$0.4	-$3.4	$4.2	$0.0	$6.4
Stress	**SB100**	$6.0	$2.8	$9.0	$5.7	-$6.8	-$9.8	-$2.2	-$6.4	$0.0

The Los Angeles 100% Renewable Energy Study

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