Appendix H
AB 32 GHG Inventory Sector Modeling

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Introduction

This appendix provides technical support documentation for the modeling analysis of the AB 32 GHG Inventory sectors. Alternative scenarios that explore technology and fuel options to reduce dependence on fossil fuels were modeled. Actions – with varying stringency – were represented in the models to explore direct emissions reductions from AB 32 GHG Inventory sectors. Any residual emissions are compensated with carbon dioxide removal. The fuel consumption and associated emissions for the alternative scenarios are used to evaluate effects on public health. The costs for the alternative scenarios are used to evaluate the effect the alternatives have on the California economy.

The Proposed Scenario and alternatives are not forecasts. They are projections of the level of GHG emission reductions that may be achieved through combinations of actions that occur between the present and 2045. The level of stringency and timing of these actions dictates the potential GHG emissions reductions. As with all projections, there will be uncertainty associated with any point estimates. The impact on GHG emissions reductions associated with varied stringency of actions is discussed in Chapter 3 and in Appendix C (AB 197 Measure Analysis).

Model outputs and results are contingent on key assumptions, limitations of data sets, and model capability to reflect the complex interactions in our energy system. For this study a wide variety of data sources is used. To the extent possible, data sources and results from other efforts are utilized. Modeling assumptions are applied consistently across alternative scenarios such that the relative differences provide useful insights.

Ultimately, future GHG emissions reductions will depend on implementation of actions identified in the Draft Scoping Plan. Implementation will consist of development of policies and regulations that consider numerous factors in addition to GHG emissions reductions. Costs and available supply of technologies and fuels are often contingent on market forces that fall outside of California's control.

This appendix describes the models, assumptions, and approaches used to develop and evaluate alternative scenarios for the AB 32 GHG Inventory sectors. The following sections of the appendix describe each of the modeling efforts:

- Energy and Environmental Economics (E3) used the California PATHWAYS model to represent fuel and technology choices on GHG emission reductions. The data sources and modeling assumptions used in the PATHWAYS model are listed here. The Reference Scenario assumptions are also included.
- CARB developed non-combustion methane and hydrofluorocarbon emissions projections and associated costs for use in PATHWAYS.

- The University of California, Irvine applied several models using fuel combustion outputs from PATHWAYS to evaluate the alternatives in terms of air quality and health benefits associated with reduced fossil fuel combustion.
- Rhodium Group used the energy system costs, fuel demand and efficiency savings to evaluate the effect the alternative scenarios would have on the California economy in terms of Gross State Product, employment, and household expenditures.

Energy and Emission Modeling

E3 conducted energy and emission modeling using the PATHWAYS model. This section of the appendix describes the PATHWAYS model, assumptions, and the Reference Scenario.

This analysis uses E3's California PATHWAYS model, an economy-wide energy and greenhouse gas model to identify long-term GHG mitigation challenges in California through analysis and comparison of different scenarios. PATHWAYS provides a detailed technology representation of all sectors of the economy (using CARB AB 32 Scoping Plan categories), including explicit modeling of building device and vehicle stock turnover. Through sector-specific emission-reduction strategies called "actions," each scenario explores different rates and scales of clean technology adoption and energy supply and demand changes.

PATHWAYS[1] calculates annual energy demand by fuel type and sector, greenhouse gas emissions, the portfolio of technology stock in selected sectors, as well as annual capital costs and fuel costs and savings out to 2050. The final energy demand projections are used to determine energy supply, while incorporation of zero- and low-carbon energy fuels determines final energy prices and emissions. Electricity rates are calculated externally in E3's RESOLVE capacity expansion model, which meets each scenario's electricity demands with specified greenhouse gas emissions constraints or renewable electric generation constraints. PATHWAYS does not capture macroeconomic or air quality impacts of each scenario.

Emissions accounting protocols used in the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report were used for this study, consistent with the California Air Resources Board statewide GHG emission inventory.

[1] PATHWAYS model described here: *https://www.ethree.com/tools/pathways-model/*

Sectoral Inputs

Financing Assumptions

Financing rate to annualize incremental equipment costs is 5% (real). Useful life of equipment is shown in Table H-1.

Table H-1. Financing assumptions

Subsector	Technology	Lifetime (years)
Residential Water Heating	Gas Water Heater	9
	Electric Heat Pump	16
Residential Space Heating	Gas Furnace	18
	Reference Gas Radiator	25
	Electric Heat Pump	18
Residential Central Air Conditioning	Air Conditioner	14
Commercial Water Heating	Gas Water Heater	12
	Electric Heat Pump	14
Commercial Space Heating	Gas Furnace	18
	Gas Boiler	25
	Electric Heat Pump	15
Commercial Air Conditioning	Reference Air Conditioner	15
Transportation Light-Duty Vehicles (LDVs)	Light-Duty Auto	17
	Light-Duty Truck	17
Transportation Medium-Duty Vehicles (MDVs)	Medium-Duty Truck	17
Transportation Heavy-Duty Vehicles (HDVs)	Heavy-Duty Truck	16
Transportation Buses	Bus	12

Buildings

References for assumptions used to describe energy demand, technology stocks, appliance costs, and technology performance are listed in Table H-2 for residential buildings and in Table H-3 for commercial buildings.

Table H-2. Residential buildings references

Description	Reference
Calibration of sectoral electricity demand input data (GWh)	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid-High, 19-IEPR-01
Calibration of sectoral pipeline gas demand input data (Mtherms)	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid-High
Reference technology shares (percent of stock)	• *All non-lighting end uses:* California Residential Appliance Saturation Survey (RASS), 2019, CEC-200-2021-005. • *Lighting*: 2015 DOE Lighting Market Characterization Report Tables
Technology costs	• *Space heating, water heating, and panel upgrade*: Residential Building Electrification in California, E3, 2019 • *All other end uses*: Annual Energy Outlook (AEO) 2021, EIA
Subsector energy or service demand consumption estimate used to calibrate total service demand (kWh and therm/household)	RASS 2019, CEC
Technology efficiencies	• AEO 2021, EIA • Calibration to CARB California Greenhouse Gas Emissions Inventory 2021 & RASS 2019

Table H-3. Commercial buildings references

Description	Reference
Calibration of sectoral electricity demand input data (GWh)	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid-High, 19-IEPR-01
Calibration of sectoral pipeline gas demand input data (Mtherms)	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid-High, 19-IEPR-01
Reference technology shares (percent of stock)	• *Non-lighting end uses*: California Commercial Saturation Survey (CCSS), 2014, prepared for California Public Utilities Commission by Itron, Inc. • *Lighting*: Department of Energy Lighting Market Characterization Report, 2015.
Technology inputs including useful life, energy type, and cost assumptions	AEO 2021, EIA
Calibration of subsector electricity and natural gas energy demand	Commercial Buildings Energy Consumption Survey (CBECS) 2012, EIA
Per-unit technology costs	AEO 2021, EIA
Technology efficiencies	• AEO 2021, EIA • Calibration to CARB California Greenhouse Gas Emissions Inventory 2021 & CCSS 2014

Transportation

References for assumptions related to the transportation sector modeling assumptions are included in Table H-4. These assumptions include fuel demand, vehicle miles travelled, vehicle stocks, fuel efficiency for internal-combustion engine vehicles and technology and cost characterization of zero-emission vehicle alternatives including associated infrastructure.

Table H-4. Transportation references

Description	Reference
Calibration of fuel demand by subsector	California Greenhouse Gas Emissions Inventory 2021, CARB
Vehicle miles travelled (on-road)	Internal analysis by CARB based on Metropolitan Planning Organization (MPO) forecasts from second Sustainable Communities Strategies (SCS) and California Department of Tax and Fee Administration (CDTFA) fuel sales data[2]
Fuel efficiency (on-road)	Vision 2.1 scenario modeling system, CARB
Vehicle stock characterization	Emission Factors Model (EMFAC) 2021, CARB
Vehicle and infrastructure costs	• *LDV*: ZEV Cost Modeling Workbook, ACC II workshop, CARB, May 2021 • *MHDV*: "Driving California's Transportation Emissions to Zero", CA Institute of Transportation Studies, April 2021 • *Hydrogen-fueled rail and ships*: U.S. DOE Hydrogen and Fuel Cells Program, Argonne National Lab, May 2020 • *Electric rail*: "Popovich, N.D. et al. Economic, environmental, and grid-resilience benefits of converting diesel trains to battery-electric" Nat Energy 6, 1017–1025, 2021 • *Hydrogen-fueled aviation*: "Hydrogen-Powered Aviation: A fact-based study of hydrogen technology, economics, and climate impact by 2050", prepared by McKinsey and co. for Clean Sky 2 and Fuel Cells and Hydrogen 2 Joint Undertakings, May 2020 • *EV charging*: California Electric Vehicle Infrastructure Project (CALeVIP) Cost Data, CEC Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment 2021, CARB Advanced Clean Trucks Initial Statement of Reasons 2019
Biofuel blending	California Greenhouse Gas Emissions Inventory 2021, CARB

Industrial Manufacturing

References for assumptions related to industrial manufacturing energy demand, energy efficiency, and energy use for individual sectors are listed in Table H-5.

[2] The base year (2019) is estimated based on gasoline consumption data from the California Department of Tax and Fee Administration (CDTFA) and fuel economy and vehicle fleet mix data from CARB's EMFAC model. The 2035 and 2045 activity data are based on the Metropolitan Planning Organization (MPO) forecast from MPOs second Sustainable Communities Strategies.

Table H-5. Industrial manufacturing references

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid, 19-IEPR-01
Sectoral pipeline gas demand input data	CARB California Greenhouse Gas Emissions Inventory 2021
Sectoral "other" energy input data	CARB California Greenhouse Gas Emissions Inventory 2021
End-use energy decomposition by subsector	2018 Manufacturing Energy Consumption Survey, EIA
Industrial energy efficiency costs	2017 Scoping Plan, updated to current dollars

Agriculture

References for assumptions related to agriculture energy demand, energy efficiency, and energy use are listed in Table H-6.

Table H-6. Agriculture references

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid, 19-IEPR-01
Sectoral pipeline gas demand input data	CARB California Greenhouse Gas Emissions Inventory 2021
Sectoral "other" energy input data.	CARB California Greenhouse Gas Emissions Inventory 2021
End-use energy decomposition by subsector	CPUC Navigant Potential Study, 2013.
Energy efficiency cost assumptions	2017 Scoping Plan, updated to current dollars

Petroleum Refining

References for assumptions related to the Petroleum Refining sector including energy demand and costs for carbon capture and sequestration as well as refinery phasedown are included in Table H-7.

Table H-7. Petroleum refining references

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid, 19-IEPR-01
Sectoral pipeline gas demand input data	CARB California Greenhouse Gas Emissions Inventory 2021
Sectoral "other" energy input data. Input	CARB California Greenhouse Gas Emissions Inventory 2021
Carbon capture and sequestration (CCS) costs	"Global costs of carbon capture and storage: 2017 update", Global CCS Institute, June 2017
Refinery phasedown costs	CARB internal analysis[3]

Oil & Gas Extraction

References for assumptions related to oil and gas extraction including energy demand and phasedown costs are listed in Table H-8.

Table H-8. Oil and gas extraction references

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2020-2030 Adopted Forecast, CEC, January 2020, Mid, 19-IEPR-01
Sectoral pipeline gas demand input data	CARB California Greenhouse Gas Emissions Inventory 2021
Sector phasedown costs	See Appendix H: *Cost Estimates for Methane Reductions from Oil and Gas Extraction and Natural Gas Transmission and Distribution*

Non-Energy Emissions

CARB developed emissions estimates and cost assumptions for use in PATHWAYS to project non-energy emissions for the Proposed Scenario and alternatives. The non-energy emissions that were modeled are listed in Table H-9 with references to the corresponding sections of this appendix for further details.

[3] Decommissioning costs were assumed to be 50% of refinery capital value, pro-rated by reduction in overall refinery capacity based on percent of refineries decommissioned by scenario. Total California refining capacity ~1.71 million barrels per day; capital value assumed to be ~$6,115/barrel per day of refining capacity based on recent refinery sales. Costs amortized over 25 years for each scenario over 2025-2050, no discount factor.

Table H-9. Non-energy emissions references

Description	Reference
Current non-energy emissions levels	Benchmarked to CARB California Greenhouse Gas Emissions Inventory 2021
HFC emission projections and reduction costs	See Appendix H: *Hydrofluorocarbon Emissions* and *Cost Estimates for Hydrofluorocarbon Actions*
Organic waste emission projections and reduction costs	See Appendix H: *Methane Emissions from Organic Waste* and *Cost Estimates for Organic Waste Actions*
Dairy and livestock emission projections and reduction costs	See Appendix H: *Methane Emissions from Dairy and Livestock* and *Cost Estimates for Dairy and Livestock Actions*
Oil and gas emission projections and reduction costs	See Appendix H: *Methane Emissions from Oil and Gas Extraction*, *Methane Emissions from Natural Gas Transmission and Distribution*, and *Cost Estimates for Methane Reductions from Oil and Gas Extraction and Natural Gas Transmission and Distribution*
Other non-energy emissions	Emissions consistent with existing AB 32 emission inventory[4]

Direct Air Capture Carbon Dioxide Removal

Direct Air Capture (DAC) technology specifications and costs were developed to support the CARB *Achieving Carbon Neutrality in California: A Report by E3.*[5] The cost information was detailed in an appendix to the report.[6]

Both liquid solvent-based DAC as well as solid sorbent-based DAC approaches were used to develop cost and technology specifications for the Scoping Plan. Solid sorbent DAC technology is based on the Climeworks 900 ton/year demonstration plant in Switzerland, and liquid solvent DAC technology is based on specifications from the National Academy of Sciences. [3] Both types of DAC require energy input that can be in the form of electricity or fuel, such as hydrogen, to produce heat at high temperatures.

For the Draft Scoping Plan, the specific type of DAC technology and the corresponding energy source was not directly modeled. For purposes of estimating the cost of DAC and maintaining consistency with the carbon neutrality targets, off-grid solar generation was assumed to provide the required energy. The DAC cost

[4] There remain considerable uncertainties with how emissions in this category may change for different strategies deployed.
[5] https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf
[6] Achieving Carbon Neutrality in California: A Report by E3 Cost Data Supplement. <https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_cost_data_supplement_oct2020.xlsx>

assumption used in this study for 2045 is \$236/tCO2 for liquid solvent approaches, and the assumptions behind this number are detailed further in the cost appendix linked above. The cost assumption for 2030 is taken to be the current cost of DAC offered by Climeworks,[4] which is approximately \$1,000/tCO2. For this study, DAC costs are interpolated between these 2030 and 2045 values (there is no DAC assumed in this study before 2030).

Macroeconomic Assumptions

The PATHWAYS model uses macro-economic assumptions related to population projections in order to estimate energy demand in future years, particularly for buildings. The references for these assumptions are listed in Table H-10.

Table H-10. Macroeconomic assumptions

Sector	Description
Population	Form P-2A: Total Population for California and Counties, Baseline Year 2019, California Department of Finance
Households	Form P-4: State and County Projected Households, Household Population, and Persons per Household 2020-2030, Baseline Year 2019, California Department of Finance
Commercial Square Footage	California Energy Demand Forecast Update, 2020 - 2030 Baseline Forecast - Mid Demand Case, Form 2.2 State Planning Area, CEC. January 2020, 19-IEPR-01

Electricity Sector Modeling Methodology

For modeling the electric sector, the RESOLVE mode was used, which is used by both the CEC and CPUC to evaluate least cost pathways for the electric sector to reach high renewables penetrations. RESOLVE is an optimal investment and operational model designed to inform long-term planning questions around integration in systems with high penetration levels of renewable energy. RESOLVE co-optimizes investment and dispatch over a multi-year horizon for a study area. RESOLVE solves for the optimal investments in energy efficiency and renewable resources as well as complementary resources such as new gas plants, gas plant retrofits, demand response, and various energy storage technologies. The portfolio is optimized subject to:

- Policy/Scenario constraints such as an RPS-style production mandate or a GHG emissions cap,
- Reliability constraints such as a capacity adequacy constraint and hourly operating reserve requirements; and
- Scenario-specific constraints on the availability of certain renewable energy resources

The inputs and assumptions to this model are largely the same as in the CEC SB 100 Joint Agency Report[7] and the CPUC IRP[8], with several changes implemented:

- Only one statewide California zone is modeled, rather than having one zone for each California Balancing Authority
- When necessary, assumptions for the CAISO jurisdiction (such as non-modeled costs in the revenue requirement) are scaled up to be statewide using a constant scalar of 0.82
- Several firm, low-carbon resources are added as resource options. Cost and performance characteristic assumptions are taken from the NREL ATB database when available and developed based on a literature review by E3 when not available.
    - Hydrogen retrofits of existing natural gas generators
        - Capital cost assumptions from the NREL 2021 Standard Scenarios Report[9]
        - Additional pipeline costs were added assuming a requirement of 50 miles of new pipeline per plant, with cost assumptions from the Hydrogen Scenario Analysis Model (HDSAM) from Argonne National Laboratory[10]
    - CCS retrofits of existing natural gas generators
        - Cost and performance assumptions for carbon-neutral CCS plants from Feron et al., 2019[11]
        - The cost to retrofit an existing plant was assumed to be the incremental cost of a new plant with CCS compared to a new plant without CCS, adjusted by a retrofit factor to account retrofit-specific costs (retrofit cost assumptions from Chou et al., 2013[12])
    - New hydrogen CTs
        - Capital cost assumptions from the NREL 2021 Standard Scenarios Report

[7] See https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity

[8] Inputs and assumptions for CPUC IRP described in full at: *https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf*

[9] NREL 2021 Standard Scenarios Report: https://www.nrel.gov/docs/fy22osti/80641.pdf

[10] Hydrogen Delivery Scenario Analysis Model (HDSAM) from Argonne National Laboratory: https://hdsam.es.anl.gov/index.php?content=hdsam

[11] Feron, P., Cousins, A., Jiang, K., Zhai, R., Thiruvenkatachari, R., & Burnard, K. (2019). Towards zero emissions from fossil fuel power stations. International Journal of Greenhouse Gas Control, 87, 188–202.

[12] Chou, Vincent, et al. *Cost and performance of retrofitting NGCC units for carbon capture*. No. DOE/NETL-2018/1896. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States), 2013.

        - Additional pipeline costs were added assuming a requirement of 50 miles of new pipeline per plant, with cost assumptions from the Hydrogen Scenario Analysis Model (HDSAM) from Argonne National Laboratory
    - New CCGT gas generators with CCS
        - Cost and performance assumptions for carbon-neutral CCS plants from Feron et al., 2019
    - New hydrogen fuel cell generators
        - Cost and performance assumptions from CEC SB 100 report[13]
    - Allam cycle CCS
        - Assumptions from Allam et al., 2017[14]
- Transmission and distribution upgrade costs are updated to the full long-term GRC value from the CPUC Avoided Cost Calculator.[15]

Implementation of SB 100 constraints is aligned with the modeling done for the SB 100 Joint Agency Report.[16]

Fuels Assumptions and Methodology

In the Draft Scoping Plan modeling, hydrogen is an alternative fuel for liquid transportation fuels and for natural gas. The mechanism of producing hydrogen is not specified. There are zero-carbon options such as electrolysis powered from zero-carbon electricity or steam methane reformation (SMR) of biogas. There are also net negative carbon emissions options such as SMR of biogas with carbon capture and sequestration. The model results provide an estimate of the quantity of hydrogen that may be needed to substitute for fossil fuel alternatives in the scenarios.

For purposes of estimating the cost of producing hydrogen and maintaining consistency with the carbon neutrality targets, it was assumed that hydrogen was produced entirely via SMR from biogas through 2025, linearly transitioning to a mix of biomass gasification with CCS and electrolysis between 2025 and 2035. Hydrogen from gasification is used as it is available, based on feedstock assumptions, and electrolysis fills in the remainder.

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[13] See https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity

[14] Allam et al. Energy Procedia. 2017. Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture. https://doi.org/10.1016/j.egypro.2017.03.1731.

[15] See ACC documentation, chapters 9 and 10: *https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2021-acc-documentation-v1b.pdf*

[16] Available at: *https://www.energy.ca.gov/sb100*

References for assumptions related to fossil fuel and alternative fuel prices, emissions intensity, and biomass-based technology costs are listed in Table H-11. CARB developed biomass energy supply estimates that are discussed in more detail in a following section of the appendix.

Table H-11. References for fuels assumptions

Sector	Description
Fossil price trajectories	AEO 2021, EIA, Reference Case
Fuel emissions intensity	Emission Factors for Greenhouse Gas Inventories, EPA 2021
Bioenergy supply	See Appendix H: *Biomass-Energy Supply*
Hydrogen costs	Price trajectory from E3 synthesis of different studies, used for "The Challenge of Retail Gas in California's Low Carbon Future" report prepared by E3 and UC Irvine for CEC, 2020
Renewable liquid fuels costs	"Comparison of "Advanced" biofuel cost estimates: Trends during rollout of low carbon fuel policies", J. Witcover and R. B. Williams, Transportation Research Part D: Transport and Environment, 2020
Biomethane costs	"Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute", A. M. Jaffe, Institute of Transportation Studies, UC Davis 2016
Bioenergy with Carbon Capture and Storage (BECCS) costs	"Current Central Hydrogen from Biomass via Gasification and Catalytic Steam Reforming", M. Mann and D. M. Steward, NREL 2018

Fuels Assumptions

Table H-12. Biomass feedstocks, fuels, and sectoral allocation

Feedstock Category	Fuel	Sectoral Allocation
Biogas from anaerobic digestion (including landfill- diverted organic wastes, dairy manure, landfill gas, and wastewater treatment)	Renewable Natural Gas (RNG)	Transportation and hydrogen production via SMR in the 2020s, phasing into pipeline blend after 2030, except for small volumes of RNG transportation use.[a]
Biomass wastes and residues (including urban, agriculture, and forestry residues)	Hydrogen (via gasification with CCS)	Transportation, allocated to hydrogen rather than liquid fuels due to opportunity for carbon sequestration and negative emissions (studies show this as the most cost-effective use of waste and residue feedstocks when used for energy).[17]
Fats, oils, and greases	RD and SAF	Transportation, transitioning to 100% sustainable aviation fuel (SAF) by 2040 with remainder going to renewable diesel (RD)
Corn	Ethanol	Transportation, maintain constant 10% blend level, resulting in phaseout as gasoline usage is phased out
[a] RNG used for pipeline blending instead of transportation in line with ZEV EO N-79-20 and because remaining natural gas pipeline consumption post-2030 reflects harder-to-decarbonize end uses such as high temperature industrial heat.		

COVID Impacts

This analysis used the EIA's Annual Energy Outlook reports for 2021 and 2020 to incorporate the impact of COVID-19 in each scenario's near- and long-term energy demand forecasts. The following table describes the methodology used in the Reference Scenario as well as the Proposed Scenario and Alternatives. At this time, there is still uncertainty as to how the economy recovers from COVID-19. The projections used are the best available data at the time of this modeling.

[17] See https://netzeroamerica.princeton.edu/the-report

Table H-13. Methodology used to incorporate impact of COVID-19 in fuels demand forecasts

Sector	Description
Residential	The annual deviation of total Pacific-region residential energy demand between 2019 to 2050 from AEO 2020 to AEO 2021 was applied to the total residential energy demand in each scenario
Commercial	The annual deviation of total Pacific-region commercial energy demand between 2019 to 2050 from AEO 2020 to AEO 2021 was applied to the total commercial energy demand in each scenario
Transportation	Domestic air travel and shipping demand (billion miles and billion ton-miles respectively) - the annual deviation of national service demand between 2019 to 2050 from AEO 2020 to AEO 2021 was applied to the relevant sector energy demand in each scenario
Industrial	• Change from 2019 to 2020 in Emissions and Production for Facilities Reporting Pursuant to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) • The annual deviation of industry energy demand by subsector between 2019 to 2050 from AEO 2020 to AEO 2021 was applied to each industry subsector energy demand in each scenario

Scenario Assumptions

Detailed modeling assumptions for the Proposed Scenario and Alternatives are in Appendix C (AB 197 Measure Analysis). All actions (across all categories of new technology ramp-up, demand change, and supply change) begin in 2023 unless otherwise specified.

Reference Scenario

The Reference Scenario assumptions as shown in Table H-14 align with current trends and include the estimated impact of all current regulations. This scenario is intended to reflect CARB's best estimate of what would occur with no further policy intervention. Studies listed in Table H-14 are included in the corresponding references in sector tables presented earlier.

Table H-14. Reference Scenario assumptions

Sector	Scenario Assumptions
Buildings	• Align with 2019 IEPR Mid-Mid (gas and electric) • 25% all-electric new construction starting in 2026, with 15% sales of electric devices for existing buildings by 2030.
Electricity	• 38 MMT statewide GHG constraint by 2030, 60% RPS by 2045, aligned with SB 100 Joint Agency Report Reference scenario
Transportation	• VMT per capita reduced 4% below 2019 levels by 2045, aligned with MSS BAU scenario • ~40% LDV ZEV sales by 2030, minimal MHDV decarbonization, aligned with CA Institute of Transportation Studies BAU scenario • No aviation, ocean-going vessel, cargo-handling equipment, or rail decarbonization beyond implementation of regulations as of 2020. • LDV fuel economy standards aligned with EMFAC 2017[18] • Truck fuel economy reflect Phase 2 GHG Standards
Industry	• No industrial manufacturing decarbonization • Petroleum refining energy demand ramped down in line with in-state petroleum demand • Oil & gas extraction ramped down to 30% below 2019 levels by 2030 and 40% by 2045, aligned with CA Institute of Transportation Studies BAU scenario
Bioenergy	• Align with LCFS through 2030 and beyond • See *Biomass-Energy Supply*
Carbon Dioxide Removal	• No CDR
Methane and HFCs	See Appendix H sections: • *Methane Emissions from Organic Waste* • *Methane Emissions from Dairy and Livestock* • *Hydrofluorocarbon Emissions*

[18] See section 3.1.8 of EMFAC 2017 documentation: *EMFAC2017 Volume III Technical Documentation V1.0.2 July 20, 2018*

Non-Combustion Methane and Hydrofluorocarbon Emissions Projections and Cost Estimates

Summary

This appendix provides the assumptions and data sources used to estimate the non-combustion methane and hydrofluorocarbon emissions and costs affiliated with actions in the Proposed Scenario and alternatives.

Methane Emissions from Organic Waste

Methane emissions associated with organic waste combines the following sources:

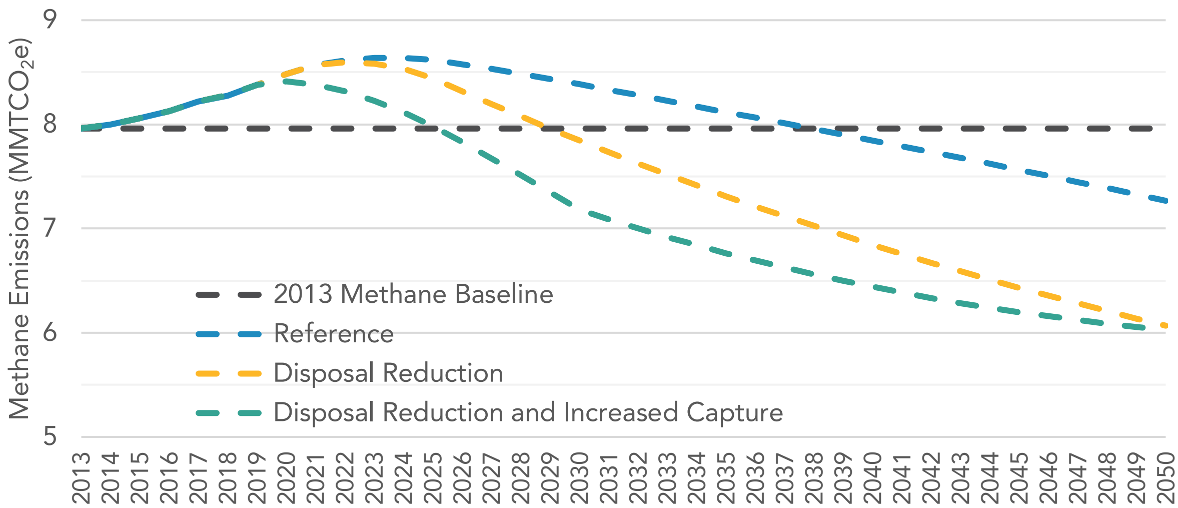
- Landfills
- Composting of landfill-diverted organic waste
- Anaerobic digestion (including co-digestion) of landfill-diverted organic waste
- Wastewater treatment (municipal and industrial)

Landfills

Methane emissions from landfills are projected using CARB's Annual GHG Inventory methodology.[19] The Reference Scenario assumes per capita waste generated remains consistent with the 2020 disposal rate (5.4 pounds per person per day), and organic waste disposal decreases modestly as organic waste recycling increases as described in the following section. All Alternative scenarios assume that the SB 1383 reduction goal is achieved by 2025, meaning that less than 6 million short tons of organic waste is landfilled in 2025 and beyond. The Proposed Scenario also reflects a 10% reduction in landfill emissions by 2030 that could be achieved through a combination of improvements to landfill gas control systems, changes in operational practices, use of lower permeability covers, advanced collection systems, and mitigation of large leaks detected through remote sensing efforts. The resulting projections of annual landfill methane emissions through 2050 are shown in Figure H-1.

[19] *https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2014/ghg_inventory_00-14_technical_support document.pdf*

Figure H-1. Projected Annual Landfill Methane Emissions ($MMTCO_2e$)



Compost and Anaerobic Digestion

CalRecycle estimates that approximately 18 million tons of organic waste will need to be processed at compost, anaerobic digestion (AD), chip-and-grind, or other organic waste processing facilities in 2025 to meet the SB 1383 reduction goal.[20] CalRecycle's Analysis of Progress provides the estimated additional capacity expected to be available in 2025, including 4 million tons of existing permitted but unutilized compost capacity, and new or expanded facilities that are under construction, planned, or funded. Alternatives 1 through 4 include the additional capacity needed in 2025 to meet the 75% disposal reduction target.[21] For Alternative 1, no increase in digestion is assumed beyond existing and near-term planned facilities; the maximum compostable organic waste is assumed to be composted. Composted tons include the digestate from digestion facilities, 36% of waste input to digestion. To calculate total emissions from compost and AD, CARB combined estimates of existing utilized capacity with CalRecycle's additional capacity projections; approximately 6 million tons of organic waste were processed in existing facilities in 2018. The total tons of organic waste used to calculate methane emissions from each source are shown in Table H-15. Note that additional organic recycling strategies are utilized for materials that are not suitable for compost and digestion, to meet the disposal reduction target.

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[20] CalRecycle (2020) Analysis of the Progress Toward the SB 1383 Waste Reduction Goals. *https://www2.calrecycle.ca.gov/Publications/Details/1693*

[21] Ibid, Table 1.

Table H-15. Organic waste diverted to compost, anaerobic digestion, and co-digestion in 2025

Scenario	Organic Waste (million short wet tons)		
	Compost	Anaerobic Digestion	Co-Digestion
Reference	11	1.8	0.2
Alternative 1	18	1.6	0.2
Alternatives 2 through 4	15	3.1	2.4

Beyond 2025, in the Reference Scenario, compost increases at a rate of 0.2 million tons per year, consistent with historical growth, and AD is conservatively assumed to increase at a similar rate in response to existing incentive programs such as LCFS, BioMAT, and the federal Renewable Fuels Standard. In the Alternative Scenarios, capacity increases consistent with population growth[22] to maintain the disposal reduction target post-2025. The projection of waste generation is a significant source of uncertainty in this analysis. Improved estimates of existing and near-term available diversion capacity will be available as jurisdictions begin complying with CalRecycle's SLCP regulations requirements for reporting in 2022.

Wastewater Treatment

Emissions from domestic and industrial wastewater treatment facilities in California is based on the Annual GHG Inventory data for 2019. Municipal wastewater treatment is assumed to increase in proportion to population growth in all scenarios, while industrial wastewater treatment remains constant, consistent with the recent trend.

Cost Estimates for Organic Waste Actions

All costs affiliated with organic waste diversion technologies were taken from the *SLCP Reduction Strategy* (Strategy) and adjusted to be in 2021 dollars.[23] All costs are assumed to be incremental to the Reference Scenario. The Strategy provides estimated costs for newly built compost facilities and anaerobic digestion facilities that can handle 100,000 short-wet-tons of organic waste per year. Additionally, the strategy estimates costs for expanding handling capacity at existing wastewater treatment plants to digest 50,000 tons of organic waste per year.

[22] Department of Finance. P-1A: State Population Projections (2010-2060). Accessed 10/21/2021 *https://www.dof.ca.gov/Forecasting/Demographics/Projections/*

[23] https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf

The capital costs for each facility were annualized over a 10-year period at a 7% interest rate. Total annual costs were compared against the facility capacity to estimate a cost per ton of waste diverted. Anaerobic digestion facilities were assumed to generate 2.4 MMBtu of biomethane per short-wet-ton of waste digested.

Project costs affiliated with bringing energy to market, such as pipeline injection and upgrading, were defined as energy costs, while facility build-out costs were allocated to the disposal facility. Energy costs were only relevant for the anaerobic digestion facilities.

Table H-16. Organic waste facility cost assumptions

Project Type	Organic Waste Disposal Cost (per short wet ton waste)	Energy Production Cost (per MMBtu biomethane)
New Compost Facility	$55	NA
Co-digestion of waste at Wastewater Treatment Plants	$110	$25
New Anaerobic Digestion Facility	$159	$35

Total annual costs for organic waste diversion were multiplied by the diversion cost affiliated with building out the necessary number of facilities to handle organic waste diversion as listed in Table H-16 for each scenario over time. For energy production costs, a weighted average of anaerobic digestion capacity (either Wastewater treatment plant co-digestion or new AD facilities). As such, the expected cost of procuring biomethane from organic food waste diversion is expected to fall between $25/MMBtu and $35/MMBtu for any given year. Because the SLCP Reduction Strategy estimated a “standard” project, these cost estimates are likely to be lower or higher than some facilities, largely depending on pipeline interconnection distance, and other variables not accounted for in the SLCP Reduction Strategy.

Methane Emissions from Dairy and Livestock

Senate Bill 1383 requires the dairy and livestock sector to reduce its methane emissions by 40 percent below 2013 levels by 2030[24], equating to approximately 9 $MMTCO_2e$ in annual reductions. These reductions can primarily be achieved through modifications to manure management activities and strategies to reduce enteric methane emissions (e.g., methane inhibiting feed additives). In addition, a decreasing animal population trend has been observed that contributes to achieving the target.

Reference Scenario

- California Climate Investments funds administered through the California Department of Food and Agriculture's Dairy Digester Research and Development Program[25] and Alternative Manure Management Program[26] are expected to reduce manure methane emissions by 2.0 $MMTCO_2e$ between 2015 and 2022.
- In addition, privately funded manure methane emissions reductions projects are expected to reduce methane emissions by 0.2 $MMTCO_2e$ between 2013 and 2022. It is assumed that no significant additional reductions will be achieved by privately funded methane emissions reduction projects beyond that point.
- No additional manure methane emissions reductions projects are expected to be implemented beyond 2030 due to uncertain funding conditions, project cost-effectiveness, and revenue streams.
- A linear annual animal population reduction of 0.5 percent (or 0.13 $MMTCO_2e$) is projected between 2013 and 2030,[27] equating to 2.34 $MMTCO_2e$ in total. Due to lack of herd projection data beyond 2030, it is assumed that animal population will stabilize between 2030 and 2050 with a reduction in the total number of dairies but a larger average dairy size as a result of consolidation.
- The total emissions reductions through population decrease, publicly and privately funded projects equate to ~4.6 $MMTCO_2e$ through 2030, leaving a 4.4 $MMTCO_2e$ shortfall in meeting the SB 1383 dairy and livestock methane reduction target.
- The Reference Scenario assumes that no additional manure management projects are implemented beyond 2020.

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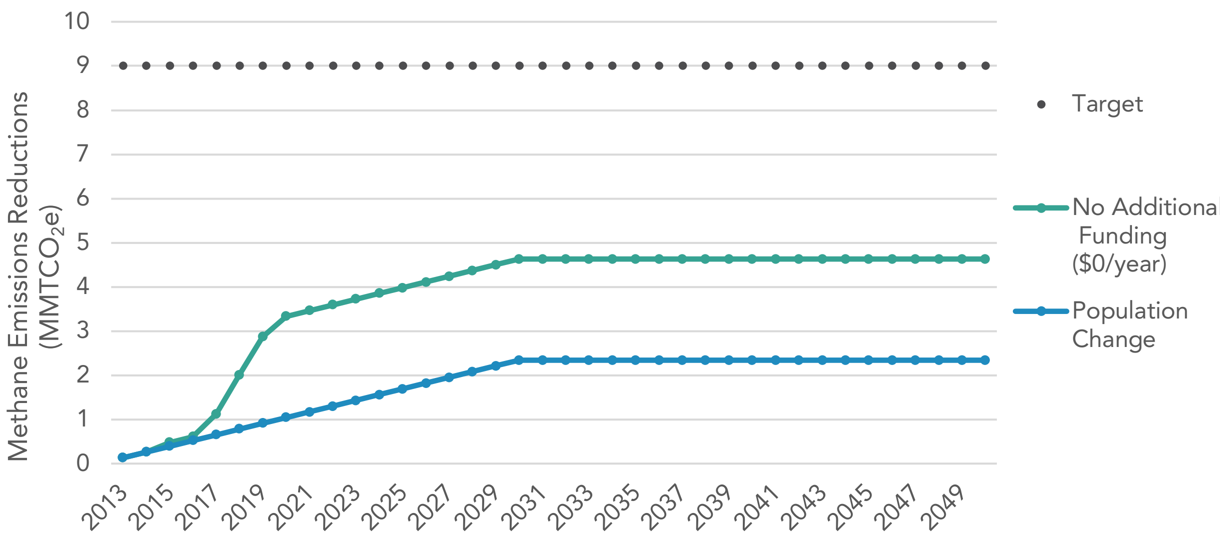
[24] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383
[25] https://www.cdfa.ca.gov/oefi/ddrdp/
[26] https://www.cdfa.ca.gov/oefi/AMMP/
[27] Animal population decreasing trend is projected based on USDA Agriculture Census data of *2012* and *2017*.

Figure H-2. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2050



Alternative 1

- A linear annual 2% animal population decrease is projected between 2013 and 2030, followed by a continued 1% population decrease through 2050.
- Maximize alternative manure management projects deployment on dairies that have not implemented a manure management project by 2030. It is assumed that an additional ~750 projects could potentially be implemented.
- No additional anerobic digester projects deployment beyond currently operating or under construction. [28]
- Implement enteric strategies across dairy and livestock operations starting in 2024 with a linear adoption rate through 2045. It is assumed that enteric strategies will reduce methane emissions by 50 percent with 75 percent of the dairy and livestock operations adopting an enteric strategy.
- The total annual methane emissions reductions achievable through net decreases in livestock population, manure methane emissions reduction projects, and enteric methane mitigation strategies deployment is projected to be ~19 $MMTCO_2e$, resulting in a sectoral net methane emission of **~3 $MMTCO_2e$** compared to the current levels of approximately 22 $MMTCO_2e$. [29]

[28] Approximately 125 anaerobic digesters are expected to be operating by the end of 2022, consistent with Table 1 (pg. 10) of the *Draft Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target*.

[29] Compared to 2019 CARB greenhouse gas emissions inventory.

Alternative 2

- A linear annual animal population change of 1 percent is projected between 2013 and 2050.
- Maximize anaerobic digester deployment on technologically feasible dairies that have not implemented a manure management project by 2030. It is assumed that an additional ~420 digesters could potentially be implemented.
- Maximize alternative manure management project deployment on dairies that have not implemented a manure management project by 2030. It is assumed that an additional ~330 alternative manure management projects could potentially be implemented.
- Implement enteric strategies across dairy and livestock operations starting in 2024 with a linear adoption rate through 2045.It is assumed that enteric strategies will reduce methane emissions by 50 percent with 75 percent of the dairy and livestock operations adopting an enteric strategy.
- The total annual methane emissions reduction achievable through net animal population decreases, manure methane emissions reduction projects, and enteric methane mitigation strategies deployment is projected to be ~20 $MMTCO_2e$, resulting in a sectoral net methane emission of **~2 $MMTCO_2e$**, compared to the current levels of approximately 22 $MMTCO_2e$.

Proposed Scenario

- A linear annual animal population change of 0.5 percent is projected between 2013 and 2050.
- Continued deployment of anaerobic digesters at dairy and livestock operations. It is assumed that an additional 380 digesters will be deployed on operations that have not implemented a manure management project by 2030.
- Continued deployment of alternative manure management strategies at dairy and livestock operations. It is assumed that an additional 210 alternative manure management projects will be deployed on dairies that have not implemented a manure management project by 2030.
- Implement enteric strategies across dairy and livestock operations starting in 2024 with a linear adoption rate through 2045. It is assumed that enteric strategies will reduce methane emissions by 30 percent with 50 percent of the dairy and livestock operations adopting an enteric strategy.
- The total annual methane emissions reduction achievable through net decreases in animal population, manure methane emissions reduction projects, and enteric methane mitigation strategies deployment is projected to be ~15 $MMTCO_2e$, leaving the sector with a net methane emission of ~**7 $MMTCO_2e$**, compared to the current levels of approximately 22 $MMTCO_2e$.

Alternative 4

- A linear annual animal population change of 0.5 percent is projected between 2013 and 2030. It is assumed that animal population will plateau beyond 2030.
- Continued deployment of anaerobic digestion technology at dairy and livestock operations. It is assumed that an additional 390 digesters will be deployed on operations that have not implemented a manure management project by 2030.
- Continued deployment of alternative manure management strategies at dairy and livestock operations. It is assumed that an additional 210 alternative manure management projects will be deployed on dairies that have not implemented a manure management project by 2030.
- Enteric strategies implementation starting in 2024 with a linear adoption rate through 2045 (30% reduction effectiveness/50% adoption rate). Enteric reduction potential is adjusted according to animal population decrease.
- The total annual methane emissions reduction achievable through net animal population decreases and manure methane emissions reduction projects is projected be ~13MMTCO$_2$e, resulting in a sectoral annual net methane emission of **~9 MMTCO$_2$e**, compared to the current levels of approximately 22 MMTCO$_2$e.

Cost Estimates for Dairy and Livestock Actions

Cost estimates used for dairy and livestock actions are provided in Table H-17. Supply curves from *Jaffe et al.* (2016) were used to estimate technology costs for deploying dairy digester projects across the state.[30] Additionally, CDFA cost information for *awarded AAMP projects* was used to estimate the "weighted average" cost for emissions reductions affiliated with AMMP projects. Finally, enteric emissions reduction costs and strategies remain uncertain. Some studies estimate that enteric emissions may be reduced for effectively zero-cost,[31,32] while other information suggests that costs may be upwards of $50 per MTCO$_2$e.[33] Given this uncertainty, it is assumed that enteric strategies would be available at a cost of $50 per MTCO$_2$e abated. All emissions reductions, and therefore scenario costs, are relative to 2013 methane emissions levels.

[30] https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/13-307.pdf

[31] https://www.feednavigator.com/Article/2021/07/08/Plant-extract-product-targeting-reduced-methane-emissions-in-dairy-cows-gets-US-launch

[32] https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0247820

[33] https://www.ecosystemmarketplace.com/articles/can-mootral-do-for-cows-what-tesla-is-doing-for-cars/

Table H-17. Estimated costs used for dairy and livestock actions

Emissions Reduction Strategy	Cost
Enteric Emissions Reductions	\$50/$MTCO_2e$
Alternative Manure Management Practices	\$48/$MTCO_2e$
Digester Projects	Based on costs from Jaffe et al. (2016)

Dairy Digester Project Costs

Dairy digesters capture and prevent the release of methane. However, the captured methane may also be redirected to energy markets or destroyed on-site. Costs affiliated with bringing the biomethane to the energy market such as pipeline buildout, compression, injection, and upgrading, were split apart from the costs to build and operate the anaerobic digester.

Using the Jaffe et al. supply curves for clustered lagoon projects, prices in USD per MMBtu of biomethane were generated and were split into costs for the dairy digester project and costs for the pipeline and energy upgrading facilities. Stoichiometric ratios and the energy density of methane was used to estimate that approximately 0.49 $MMTCO_2e$ of methane emissions would be avoided per trillion Btu of biomethane produced. For each of the scenarios, the Jaffe et al. supply curves were used to provide estimated digester costs and energy costs associated with achieving a specific level of emissions reductions from digester projects.

Digester costs were attributed to methane emissions reduction strategies, and were accounted for as being the sum of total anaerobic digestion capital costs and operational costs to achieve a given level of reduction. Energy costs, on the other hand, were assumed to be at the marginal cost of pipeline buildout, injection, and operation costs for the last dairy project cluster needed to obtain a specific level of emissions reduction. In this way, energy costs are priced at the margin, while digester project costs are priced at the total cost (no producer surplus).

All costs were inflation adjusted to 2021 dollars.

Livestock Population Reduction Estimates

For the Scoping Plan scenarios, various population reduction assumptions were used as provided in Table H-18.

Table H-18. Dairy and livestock population reduction assumptions

Scenario	Assumptions
Reference	0.5% per year to 2030, then constant herd size through 2050
Alternative 1	2% between per year between 2013 and 2030, 1% reduction per year from 2031 to 2050
Alternative 2	1% reduction per year between 2013 and 2050
Proposed Scenario	0.5% reduction per year between 2013 and 2050
Alternative 4	0.5% per year to 2030, then constant herd size through 2050

Summary of Scenario Costs

The overall revenue structure for the dairy industry is assumed to be linearly related to the dairy population size. Lost revenue to the industry in California is therefore assumed to correspond directly to the cumulative decrease in the dairy population. Total revenue for dairy and cattle operation livestock *for 2012* were used, and population reductions as provided above were used to decrease the total economic value of the industry.[34] The difference between the Reference case and the alternative scenario assumptions provides the incremental cost given in Table H-20Table H-23 below.

[34]https://www.nass.usda.gov/Publications/AgCensus/2017/Full_Report/Volume_1,_Chapter_1_State_Level/California/st06_1_0002_0002.pdf

Table H-19. Dairy and livestock methane emissions mitigation costs (million dollars per year, 2021 dollars)

Scenario	2025	2030	2035	2040	2045	2050
Alternative 1	$106	$171	$208	$244	$281	$281
Alternative 2	$198	$379	$416	$452	$489	$489
Proposed Scenario	$189	$343	$360	$377	$395	$395
Alternative 4	$195	$353	$370	$388	$405	$405
Reference	$63	$63	$63	$63	$63	$63

Table H-20. Dairy and livestock population reduction incremental costs (million dollars per year, 2021 dollars)

Scenario	2025	2030	2035	2040	2045	2050
Alternative 1	$2,022	$2,632	$3,042	$3,432	$3,803	$4,156
Alternative 2	$715	$954	$1,446	$1,915	$2,360	$2,784
Proposed Scenario	$0	$0	$272	$538	$797	$1,050
Alternative 4	$0	$0	$0	$0	$0	$0

Table H-21. Dairy and livestock energy procurement costs ($/MMBtu, 2021 dollars)

Scenario	2025	2030	2035	2040	2045	2050
Alternative 1	$18.89	$18.89	$18.89	$18.89	$18.89	$18.89
Alternative 2	$27.28	$42.22	$42.22	$42.22	$42.22	$42.22
Proposed Scenario	$27.28	$39.95	$39.95	$39.95	$39.95	$39.95
Alternative 4	$26.61	$39.95	$39.95	$39.95	$39.95	$39.95
Reference	$18.89	$18.89	$18.89	$18.89	$18.89	$18.89

Methane Emissions from Oil and Gas Extraction

- Non-combustion emissions from oil and gas extraction include vented and fugitive methane emissions, which are both part of Oil & Gas Production & Processing -- Fugitive Emissions in the CARB Annual GHG Inventory. Inventory data used for this analysis was corrected based on rulemaking data (those changes will be reflected in the 2022 edition of the inventory).
- All alternatives include emission reductions from CARB's Oil and Gas Methane Regulation beginning in 2020 when full implementation began (based on estimated emission reductions during rulemaking).

Reference Scenario

- Emissions reductions of fully implemented regulation estimated during rulemaking to be 0.5 $MMTCO_2e$/year.
- Will result in ~41% emissions reductions by 2030 and 2045 relative to the baseline 2013 emissions (1.20 $MMTCO_2e$).

Alternative 1

- Linear phaseout of extraction from 2025 to 2035.
- When combustion is phased out, the remaining emissions from the sector are from idle and improperly abandoned wells. 2007 inventory data was used (and corrected based on rulemaking data) to estimate the fraction of emissions from all wells (overestimated to be conservative) and multiplied by 2025 emissions.

Alternative 2

- Additional emission reductions (beyond current Oil and Gas Methane Regulation) could be achieved beginning in 2025, and it was assumed that decreases in emissions would occur linearly.
- Oil and gas methane reduces in line with demand reductions between 2030 and 2035.
- For phaseout of oil and gas extraction, it was assumed that when there is no extraction, the remaining emissions will be from idle and improperly abandoned wells, and natural gas underground storage. 2007 inventory data (and corrected based on rulemaking data) was used to estimate the fraction of emissions from those sources (overestimated to be conservative) and multiplied by 2030 emissions (since for these alternatives there will be reductions to get us to 2030).

Proposed Scenario

- Additional emission reductions (beyond current Oil and Gas Methane Regulation) could be achieved beginning in 2025, and it was assumed those decreases in emissions would occur linearly.
- Oil and gas methane reduces in line with demand reductions between 2030 and 2045, with phaseout of oil and gas extraction completing in 2045. For phaseout of oil and gas extraction, it was assumed that when there is no extraction, the remaining emissions will be from idle and improperly abandoned wells, and natural gas underground storage. The 2007 inventory data was used (and corrected based on rulemaking data) to estimate the fraction of emissions from those sources (overestimated to be conservative) and multiplied by 2030 emissions (since for these alternatives there will be reductions to get us to 2030).

Alternative 4

- Additional emission reductions (beyond current Oil and Gas Methane Regulation) could be achieved beginning in 2025, and it was assumed those decreases in emissions would occur linearly.
- Oil and gas methane reduces in line with demand reductions starting in 2030. For reduction in oil and gas extraction, it was assumed emissions from idle and improperly abandoned wells, and natural gas underground storage could not be reduced beyond 2030 levels, then used similar calculation methods to Alternative 2 and the Proposed Scenario.
- Assumed linear reduction in emissions (excluding emissions from storage and wells) from 2030 to 2050 as extraction is reduced.
- Since petroleum demand data for 2030 and 2050 was not available prior to developing Scoping Plan scenarios, it was assumed that from 2013 to 2050

there would be a 90% reduction in petroleum demand, similar to the 2020 E3 report.[35]

Methane Emissions from Natural Gas Transmission and Distribution

- Natural Gas Transmission and Distribution Emissions include vented and fugitive methane emissions, including "Industrial - Transmission and Distribution - Natural Gas Pipelines – Fugitives - Fugitive Emissions" and "Industrial - Transmission and Distribution – Natural Gas – Natural Gas Storage – Fugitive Emissions" in the GHG inventory.
- All alternatives include emission reductions from CPUC's SB 1371 Natural Gas Leak Abatement program, which is implementing 26 best practices.
- Hydrogen blending levels into the natural gas pipeline are provided on an energy basis to estimate methane leaks from gas transmission and distribution.

Reference

- Full implementation of CPUC Decisions related to SB 1371 anticipated to result in 20% reduction in GHG emissions by 2025 (i.e., 0.81 $MMTCO_2e$ reduction) and 40% reduction in GHG emissions by 2030 (i.e., 1.6 $MMTCO_2e$ reduction) relative to SB 1371 baseline year of 2015 (2015 emissions were 4.05 $MMTCO_2e$).[36]
- Will result in ~39% reduction in GHG emissions by 2030 and 2045 relative to 2013 levels (2013 emissions were 3.98 $MMTCO_2e$).[37]

Alternative 1

- 20% reduction in natural gas emissions by 2025 relative to 2015 (SB 1371).
- 50% reduction in natural gas emissions by 2030 relative to 2013 (SB 1383).
- 100% reduction in natural gas emissions by 2035 relative to 2013.

Alternative 2

- 20% reduction in natural gas emissions by 2025 relative to 2015 (SB 1371).
- 50% reduction in natural gas emissions by 2030 relative to 2013 (SB 1383).

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[35] https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf
[36] GHG emissions for "Pipeline Fugitive Emissions" were estimated based on the CARB GHG emissions inventory, which does not currently include all emissions categories associated with natural gas transmission and distribution in the SB 1371 inventory. Nonetheless, the Reference Scenario may overestimate fugitive emissions associated with natural gas transmission and distribution by 33 to 55 percent, based on a comparison with the SB 1371 emissions inventory.
[37] Ibid.

- Hydrogen blended in natural gas pipeline, ramping up linearly from 0% in 2030 to 7% energy (~20% by volume) in 2040 and staying constant at 7% energy through 2050.
- Treatment of RNG leaks the same as fossil natural gas leaks (conservative).
- Pipeline leaks are independent of natural gas throughput, and therefore no additional reductions resulting from demand reduction (conservative).

Proposed Scenario

Assumptions for the Proposed Scenario are the same as the assumptions for Alternative 2.

Alternative 4

- 20% reduction in natural gas emissions by 2025 relative to 2015 (SB 1371).
- 45% reduction in natural gas emissions by 2030 relative to 2013 (SB 1383).
- Hydrogen blended in natural gas pipeline, ramping up linearly from 0% in 2030 to 7% energy (~20% by volume) in 2040 and staying constant at 7% energy through 2050.
- Treatment of RNG leaks the same as fossil natural gas leaks (conservative).
- Pipeline leaks are independent of natural gas throughput, and therefore no additional reductions resulting from demand reduction (conservative).

Cost Estimates for Methane Reductions from Oil and Gas Extraction and Natural Gas Transmission and Distribution

All costs presented in Table H-22. represent the average annual cost over the 2025 to 2050 timeframe affiliated with achieving emissions targets incremental to Reference Scenario.

Table H-22. Oil and Gas extraction and natural gas transmission and distribution (T&D) methane emissions annual incremental costs ($/year)

Scenario	Emissions Category	Average Annual Costs
Reference	Oil and Gas Extraction	$0
	Natural Gas T&D	$0
Alternative 1	Oil and Gas Extraction	$52,538,682
	Natural Gas T&D	$ 57,568,563
Alternative 2	Oil and Gas Extraction	$57,629,741
	Natural Gas T&D	$31,130,135
Proposed Scenario	Oil and Gas Extraction	$64,344,021
	Natural Gas T&D	$31,130,135
Alternative 4	Oil and Gas Extraction	$64,422,470
	Natural Gas T&D	$25,565,067

Costs for Methane Reductions from Oil and Gas Extraction:

- The costs of plugging and abandoning wells is excluded, since the emission projections for Alternatives 1 through 4 were based on the assumption that there would be emissions remaining from idle and improperly abandoned wells. Costs for decommissioning oil and gas extraction facilities were estimated by assuming that decommissioning costs would be 50% of capital costs for major pieces of equipment at oil and gas extraction facilities (based on the Oil and Gas Methane Regulation ISOR Appendix B[38]). Equipment counts were taken from CARB's regulatory reporting data for 2019. These are the pieces of equipment that were included, along with the source of their capital cost estimates:
    - Separators[39]
    - Storage tanks[39]
    - Compressors at oil and gas production facilities[39]
    - Compressors at natural gas gathering and boosting stations[39]
    - Pneumatic controllers[40]: note that these included both natural gas powered controllers (from regulatory reporting data) and electric and air powered controllers (from *CARB's 2007 industry survey*[41]), but the capital cost for instrument air powered controllers was used since venting from pneumatic controllers would be prohibited for all 4 alternatives.
    - Vapor collection systems[42]: note that these were roughly estimated using the number of separators at oil and gas extraction facilities and the number of compressors at natural gas gathering and boosting stations.
- Costs for decommissioning natural gas underground storage facilities were estimated using similar methods to oil and gas extraction facilities. Compressors at natural gas underground storage facilities were assumed to have the same capital costs as compressors at natural gas gathering and boosting stations.
- The cost of prohibiting venting from pneumatic controllers was estimated based on the costs to convert natural gas powered pneumatic controllers to instrument air[43], since that was the most expensive of the mitigation methods evaluated and would therefore provide the most conservative cost estimate. An

[38] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasappb.pdf
[39] https://onlinelibrary.wiley.com/doi/pdf/10.1002/9783527611119.app4
[40] https://www.epa.gov/sites/default/files/2016-06/documents/ll_instrument_air.pdf
[41] https://ww2.arb.ca.gov/sites/default/files/2020-04/FinalReportRevised_4.pdf
[42] https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf
[43] https://www.epa.gov/sites/default/files/2016-06/documents/ll_instrument_air.pdf

equipment lifetime of 7 years was used to calculate the capital recovery factor (based on the Oil and Gas Methane Regulation ISOR Appendix B[44]).

Costs for Methane Reductions from Natural Gas Transmission and Distribution:

The following assumptions/references apply to the five scenarios, where appropriate:

- Costs associated with increasing the level of emissions reductions for CPUC's Natural Gas Leak Abatement (NGLA) program will depend on the specific emissions reductions strategies that will be deployed, which may include limiting blowdowns, fixing large leaks faster, conducting shorter leak survey-cycle and other cost-effective mitigation strategies. However, the specific strategies that may be used are currently unknown. Therefore, costs were estimated for these additional emissions reductions based on a cost per ton of \$28/$MTCO_2e$ (most recent California Cap-and-Trade program auction price). It is assumed that estimated annual costs are recurring because the activities associated with the emission reduction strategies are also on-going (i.e., annual cost is not divided by 25 years).[45]
- Costs associated with decommissioning of the low-pressure natural gas pipeline network include materials and labor of putting permanent caps at the beginning and/or end of the lines; no salvage values of old materials or equipment are assumed. It is assumed that approximately 5,000 Distribution Metering and Regulation stations and about 11.5 million residential and commercial meter set assemblies will need to be capped at an estimated cost of \$2,000 per station and \$100 per customer meter, which includes the cost of materials and labor.
- Costs associated with hydrogen blending of 20% by volume into the natural gas pipeline network include construction and operation of facilities and supporting infrastructure to compress and inject hydrogen into natural gas pipeline network. Costs were estimated at \$50 million per facility with 10 facilities constructed to support this activity. No additional pipeline maintenance or upgrading costs are assumed associated with blending of 7% hydrogen by energy (~20% by volume).[46]

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[44] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasappb.pdf
[45] https://ww2.arb.ca.gov/sites/default/files/2020-08/results_summary.pdf
[46] https://www.nrel.gov/docs/fy13osti/51995.pdf

Hydrofluorocarbon Emissions

Hydrofluorocarbon (HFC) emissions are expected to continue decreasing from current levels to the levels required by SB 1383, i.e., 40 percent below 2013 emissions levels by 2030 (California SB 1383, 2016). In part, emissions reductions will be realized through reduction measures specified in the CARB Short-Lived Climate Pollutant Strategy.

The methodology and emissions factors used to estimate HFC emissions is described in CARB's Emission Inventory Methodology and Technical Support Document.[47] The methodology used to estimate HFC emissions reductions from an HFC phasedown is described in CARB's study on the Potential Impact of the Kigali Amendment on California HFC Emissions.[48]

Table H-23 provides a summary of the main assumptions used to develop each scenario.

Table H-23. Summary of HFC assumptions in the Scoping Plan Scenarios

Scenario	HFC Emissions Estimates – Main Assumptions
Alternative 1	This is the most aggressive building electrification (BE) scenario with forced retrofits of high-GWP equipment. It includes the most ambitious reduction strategies, including very low-GWP limits for new and existing HFC sources and mandatory retrofits/replacements of existing high-GWP equipment as listed in Table H-24. These limits are technologically feasible but economically and logistically challenging.
Alternative 2	Alternative 2 is a less aggressive BE scenario compared to Alternative 1. It includes a slower rate of BE, and appliance replacement at the end-of-life rather than retrofits before the natural equipment turnover/time of retirement.

[47] https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_tsd_00-14.pdf
[48] https://ww2.arb.ca.gov/sites/default/files/2018-12/CARB-Potential-Impact-of-the-Kigali-Amendment-on-HFC-Emissions-Final-Dec-15-2017.pdf

	Beyond BE measures, less aggressive and delayed GWP limits are applied to new heat pump equipment compared to Alternative 1 (HFC limits are listed in Table H-25.).
Proposed Scenario	The HFC emissions reduction goal of SB 1383 is assumed to have been met in this scenario. In this scenario, it is assumed that no additional limits are enacted after the 2030 HFC emissions goal has been met.
Alternative 4	For HFC emissions estimates, Alternative 4 is the same as the Proposed Scenario described above.

Table H-24 provides the GWP limits modeled for Alternative 1. Bolded entries indicate existing GWP limits.

Table H-24. GWP limits for New and Existing Equipment for Alternative 1

End-use	GWP limit	Effective Date
HP water heater	1	2026
HP clothes dryer	1	2026
HP pool and spa	150	2030
Portable/room AC/PTAC I (new)	**750**	**2023**
Space conditioner (AC and HP) (new)	**750**	**2025**
VRFs I (new)	**750**	**2026**
Portable/room AC/PTAC (New)	1	2026
HP space conditioner (New)	150	2030
VRFs (New)	150	2030
Space conditioner (AC and HP) (Existing)	150	2035
Commercial Ref. > 50 lb (New)	**150**	**2022**
Commercial Ref. > 50 lb (Existing)	**1400**	**2030**
Commercial Ref. > 50 lb (New)	1	2025
Commercial Ref. > 50 lb (Existing)	1	2035
Commercial Ref. < 50 lb (New)	1	2025
Commercial Ref. < 50 lb (Existing)	1400	2035
Commercial Ref. < 50 lb (Existing)	1	2040
Industrial Process Refrigeration + Cold Storage (New)	**150**	**2022**

End-use	GWP limit	Effective Date
Industrial Process Refrigeration + Cold Storage (New)	1	2030
Industrial Process Refrigeration + Cold Storage (Existing)	1	2035
Chillers (AC + IPR) (New)	**750 - 2200**	**2024**
Chillers (New)	1	2030
Chillers (Existing)	1	2035
MVAC – light duty (New)	10	2025
MVAC Electric – light duty (New)	150	2030
MVAC Gasoline & Electric – heavy duty and other (New)	150	2030
Transport Refrigerated Unit (TRU) (New)	**2200**	**2025**
Transport Refrigerated Unit (TRU) (New)	1	2030
Transport Refrigerated Unit (TRU) (Existing)	2200	2025
National HFC Phasedown – "Average case scenario"	85% below baseline	2021-2036

Table H-**25**. provides the GWP limits modeled for Alternative 2. Bolded entries indicate existing GWP limits and italicized items indicate GWP limits that are different from Alternative 1; they either have slower effective dates or have been struck out if they are not included in Alternative 2.

Table H-25**. GWP limits modeled for Alternative 2**

End-use	GWP limit	Effective Date
HP water heater	1	2026
HP clothes dryer	1	2026
HP pool and spa	150	2030
Portable/room AC/PTAC I (new)	**750**	**2023**
Space conditioner (AC and HP) (new)	**750**	**2025**
VRFs I (new)	**750**	**2026**
Portable/room AC/PTAC (New)	1	2026
HP space conditioner (New)	150	2030
VRFs (New)	150	2030
~~Space conditioner (AC+HP) (Existing)~~	*~~150~~*	*~~2035~~*
Commercial Ref. > 50 lb (New)	**150**	**2022**
Commercial Ref. > 50 lb (Existing)	**1400**	**2030**
Commercial Ref. > 50 lb (New)	1	2025
Commercial Ref. > 50 lb (Existing)	*1*	*2040*
Commercial Ref. < 50 lb (New)	1	2025
Commercial Ref. < 50 lb (Existing)	1400	2035
Commercial Ref. < 50 lb (Existing)	1	2040
Industrial Process Refrigeration + Cold Storage (New)	**150**	**2022**
Industrial Process Refrigeration + Cold Storage (New)	1	2030
~~Industrial Process Refrigeration + Cold Storage (Existing)~~	*~~1~~*	*~~2035~~*
Chillers (AC + IPR) (New)	**750 - 2200**	**2024**
Chillers (New)	1	2030
Chillers (Existing)	*1*	*2040*
MVAC – light duty (New)	10	2025
MVAC Electric – light duty (New)	150	2030
MVAC Gasoline & Electric – heavy duty and other (New)	150	2030

End-use	GWP limit	Effective Date
Transport Refrigerated Unit (TRU) (New)	**2200**	**2025**
Transport Refrigerated Unit (TRU) (New)	1	2030
Transport Refrigerated Unit (TRU) (Existing)	2200	2025
National HFC Phasedown – "Average case scenario"	85% below baseline	2021-2036

GWP Limits for the Proposed Scenario and Alternative 4 are the same. GWP limits included in the Proposed Scenario and 4 include existing limits in place (which are listed in Table H-30 below). It is assumed that the SB 1383 target is met even if the pathway towards meeting that goal is still under evolution.

Table H-26. GWP limits modeled for the Proposed Scenario and Alternative 4

End-use	GWP limit	Effective Date
Portable/room AC/PTAC I (new)	750	2023
Space conditioner (AC and HP) (new)	750	2025
VRFs I (new)	750	2026
Commercial Ref. > 50 lb (New)	150	2022
Commercial Ref. > 50 lb (Existing)	1400	2030
Industrial Process Refrigeration + Cold Storage (New)	150	2022
Chillers (AC + IPR) (New)	750 - 2200	2024
Transport Refrigerated Unit (TRU) (New) - Proposed	2200	2023
National HFC Phasedown – "Average case scenario"	85% below baseline	2021-2036

Cost Estimates for Hydrofluorocarbon Actions

HFC Costs for Alternative 1 and 2

There are two sets of additive costs to implement HFC emissions reduction limits from Alternatives 1 and 2. The first is a set of "fixed" sector-wide costs per year that excludes all costs for heat pump technologies as shown in Table H-27, and the second is a set of unit-specific costs associated with various heat pump technology adoption rates as generated by the PATHWAYS model (Table H-28). Costs for heat pump water heaters, clothes dryers, pool and spa heaters and space conditioners are estimated per unit.

HFC Costs for Proposed Scenario and Alternative 4

HFC costs for the Proposed Scenario and Alternative 4 were assumed to be zero because they only account for existing measures in place. As such, costs for these alternatives have already been accounted for. It's likely that additional measures will be necessary to meet the SB 1383 target by 2030, but the associated costs have considerable uncertainty and are not included in the cost estimates for the Proposed Scenario and Alternative 4.

Table H-27. Annualization of incremental cost data for Alternatives 1 and 2. The Proposed Scenario and Alternative 4 are identical to the reference case.

Year	Alternative 1 Total Annual Cost ($MM 2021)	Alternative 2 Total Annual Cost ($MM 2021)
2020	$0	$0
2021	$0	$0
2022	$0	$0
2023	$4	$4
2024	$0	$0
2025	$9	$9
2026	$41	$41
2027	$226	$226
2028	$226	$226
2029	$226	$226

Year	Alternative 1 Total Annual Cost ($MM 2021)	Alternative 2 Total Annual Cost ($MM 2021)
2030	$251	$251
2031	$1,939	$265
2032	$1,939	$265
2033	$1,939	$265
2034	$1,939	$265
2035	$1,939	$265
2036	$1,587	$907
2037	$1,587	$907
2038	$1,587	$907
2039	$1,587	$907
2040	$1,587	$907
2041	$251	$251

Year	Alternative 1 Total Annual Cost ($MM 2021)	Alternative 2 Total Annual Cost ($MM 2021)
2042	$251	$251
2043	$251	$251
2044	$251	$251
2045	$251	$251
2046	$0	$0
2047	$0	$0
2048	$0	$0
2049	$0	$0
2050	$0	$0
Cumulative Cost	**$19,870**	**$8,099**

Table H-28. Annualization of incremental unit cost data for Alternatives 1 and 2

	Alternative 1	Alternative 2	Proposed Scenario and Alternative4
Building electrification (BE) costs for HFCs	$/unit costs are provided for low-GWP HPs, which can be multiplied with expected unit numbers based on the rate of BE	$/unit costs are provided for low-GWP HPs, which can be multiplied with expected unit numbers based on the rate of BE	0
Incremental cost of low-GWP space conditioning HPs ($/unit)	700 - 2200	700 - 2200	0
Incremental cost of low-GWP water heater HPs ($/unit)	300 - 1500	300 - 1500	0
Incremental cost of low-GWP clothes dryer HPs ($/unit)	200 - 500	200 - 500	0
Incremental cost of low-GWP pool and spa HPs ($/unit)	500 - 1000	500 - 1000	0

Description of Methods and Assumptions Used for Estimating Cost

The assumptions used in developing cost estimates for the HFC limits modeled in Alternatives 1 and 2 are listed in Table H-29 and in Table H-30. Alternatives 3 and 4 are equivalent for HFCs. They include HFC limits legislatively mandated and/or publicly announced. Costs are reported in 2021 dollars for all limits. The timeframe for costs is from the date an HFC limit occurs until 2045.

For most limits, only upfront equipment and installation costs were taken into consideration. While there are expected to be ongoing costs, they are minimal in most cases compared to the upfront cost so were not considered in this analysis.

The mid-point cost for the cost range of limits, other than for building electrification, was utilized to estimate annual costs that could be implemented into the PATHWAYS model. Spending to achieve "new equipment" deployment was divided over a 5-year period ending with the date a limit was effective. For "existing equipment" HFC limits, it was assumed that spending would occur as existing equipment reached its end of life, and that this would result in equal weighting of cost each year. Table H-27 shows this annualization of cost data. **Bolded entries** indicate existing regulatory measures included in all four Alternatives 1-4. *Italicized entries* indicate limits that were only included in Alternative 1 and not in Alternative 2.

Table H-29. Cost estimates for HFC actions in Alternatives 1 and 2

End-use	Incremental cost (%)	Incremental cost ($/unit)	Total Cost of limit until 2045 ($M)
HP water heater	10 - 50	300 - 1500	N/A
HP clothes dryer	20 – 50	270 - 680	N/A
HP pool and spa	10 – 20	500 - 1000	N/A

End-use	Incremental cost (%)	Incremental cost ($/unit)	Total Cost of limit until 2045 ($M)
Portable/room AC/PTAC I (new)	**0**	**0**	**0**
Space conditioner (AC and HP) (new)	**0**	**0**	**0**
VRFs (new)	**0**	**0**	**0**
Portable/room AC/PTAC (New)	10	40	626
HP space conditioner (New)	10	700	N/A
Commercial HPs (New)	10	2200	N/A
Space conditioner (HP) (Existing)[a]	*0-100*	*7700*	*N/A*
Commercial Ref. > 50 lb (New)	**0**	**0**	**0**
Commercial Ref. > 50 lb (Existing)	**0**	**0**	**0**

End-use	Incremental cost (%)	Incremental cost ($/unit)	Total Cost of limit until 2045 ($M)
Commercial Ref. > 50 lb (New)	0	0	0
Commercial Ref. > 50 lb (Existing)	*50*	*55,450 – 694,500*	*3,400*
Commercial Ref. < 50 lb (New)	10 – 50	5,500 – 28,000	66-328
Commercial Ref. < 50 lb (Existing)	50	600	68
Commercial Ref. < 50 lb (Existing)	50	28,000	3,281
Industrial Process Refrigeration (IPR) + Cold Storage (New)[c]	**0**	**0**	**0**
IPR + Cold Storage (New)	0	0	0
IPR + Cold Storage (Existing)	*50 - 100*	*71,800 – 1,610,000*	*1,572-3,261*

End-use	Incremental cost (%)	Incremental cost ($/unit)	Total Cost of limit until 2045 ($M)
Chillers (AC) (New)[d]	**0**	**0**	**0**
Chillers (AC) (New)[d]	-	8150	12
Chillers (AC) (Existing)[d]	*50 – 100*	*158,750 -317,500*	*3,019 – 6,037*
Chillers (IPR) (New)[c,d]	**0**	**0**	**0**
Chillers (IPR) (New)[d]	20	28,720-264,600	56
Chillers (IPR) (Existing)[d]	*50 - 100*	*71,800 – 1,323,000*	*951-1,902*
MVAC – light duty (New)	0	0	0
MVAC Electric – light duty (New)	10	130	3,263
MVAC – heavy duty and other (New)	10	200	130
MVAC Electric– heavy duty and other (New)	10	200	130

End-use	Incremental cost (%)	Incremental cost ($/unit)	Total Cost of limit until 2045 ($M)
Transport Refrigerated Unit (TRU) (New)	**0**	**0**	**0**
Transport Refrigerated Unit (TRU) (New)	50	22,500	332
Transport Refrigerated Unit (TRU) (Existing)	150	40 -100	4
National HFC Phasedown – "Best-case scenario"	**0**	**0**	**0**

[a] Some space conditioning HPs will be installed in an effort to electrify existing buildings either to replace gas furnaces and/or air conditioners. Some lower-GWP space conditioning HPs will be installed in place of higher-GWP heat pumps in buildings that have already been electrified. In the former, the cost attribution for HFCs is 0 and in the latter, the cost attribution for HFC reduction is 100%. The number of HP replacements in an effort to electrify buildings is unknown.

[c] In line with the assumptions made in the 2020 HFC regulation, it is assumed that 50% of IPR refrigeration systems are chillers and 50% are not chillers, i.e., typical direct expansion refrigeration systems.

[d] The baseline cost of AC and IPR chillers doesn't consider the cost of the secondary loop, which is assumed to be independent of the primary refrigerant in the chiller. When replacing existing chillers, it is assumed that the secondary loop/refrigerant are not replaced.

Table H-30. Assumptions for hydrofluorocarbon costs.

End-use	Assumptions for estimating cost
HP water heater (HPWH)	• Baseline costs are assumed to be upfront equipment and installation costs.[49,50] • For the lower end of the range, it is assumed that the cost of low-GWP HPWHs will be double, i.e., 10%, the incremental cost assumed in the ISOR[51] for the upfront costs of low-GWP space conditioning units, i.e., ~5%. The cost of the transition is based on cost of converting from conventional HFC refrigerants to low-GWP alternatives with similar properties, being investigated for use. • For the upper end of the range, an incremental cost of 50% is assumed based on cost estimates for a commercially available CO_2 HPWH. CO_2-based units have higher upfront costs compared to HFC counterparts. They are more efficient, thus, their operating costs may be lower. However, energy efficiency and operational costs are not considered in this analysis.[52]
HP clothes dryer (HPCD)	• Baseline costs for HPCDs are an average of estimates obtained from a research study[53] and from CEC's IEPR 2021[54]. • Because there are no commercially available low-GWP HPCDs, it is assumed that the lower end of the range of transitioning from conventional high-GWP units to low-GWP one is 20%.

[49] CEC AB 3232 public docket log. SMUD Residential Electrification Project Costs submitted on 9/22/2020. *https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-DECARB-01*
[50] Remodeling Expense, "Cost of Heat Pump Water Heaters," January 2022. *Cost of Heat Pump Water Heaters - Types & Install Prices (remodelingexpense.com)*
[51] CARB 2020 HFC Regulation Initial Statement of Reasons (ISOR). October 2020. *Staff Report ISOR HFC (ca.gov)*
[52] Hoeschele, M., Haile, J. PG&E Residential Code Readiness Project: Monitoring of a Split System CO_2 Heat Pump (2019). *PG&E Residential Code Readiness Project: Monitoring of a Split System CO2 Heat Pump | ETCC (etcc-ca.com)*
[53] Meyers, Steve, Franco, Victor, Lekov, Alex, Thompson, Lisa, and Sturges, Andy. Do Heat Pump Clothes Dryers Make Sense for the U.S. Market. United States: N. p., 2010. *https://www.osti.gov/biblio/1022740*
[54] California Energy Commission 2021 Integrated Energy Policy Report Volume I Building Decarbonization. February 2022.

End-use	Assumptions for estimating cost
	• At the upper end, incremental costs are assumed to be 50%, similar to the assumptions for HPWHs, since the low-GWP alternatives are expected to be similar for both categories.
Pool and spa HP	• Baseline costs for HPs used for heating pools and spas were obtained from Google searches/blogs. • Pool and spa heaters use similar refrigerants as space conditioning units so the costs of transitioning from high- to low-GWP units are expected to be similar. However, because no low-GWP units are currently commercially available, it is assumed that incremental costs will be 10-20 % for this equipment category.
Portable/room AC/PTAC I (new) – 750 GWP limit	• No incremental costs are assumed since this is an existing regulatory requirement.
Space conditioner (AC and HP) (new) – 750 GWP limit	• No incremental costs are assumed since this is an existing regulatory requirement.
VRFs I (new) – 750 GWP limit	• No incremental costs are assumed since this is an existing regulatory requirement.
Portable/room AC/PTAC (New) – 1 GWP limit	• Baseline costs were obtained from the DOE[55] and Google searches. • Ultra-low-GWP units (GWP < 10) are mandated in Europe and are readily available in many countries. To be conservative, it is assumed that bringing this technology to the US will have incremental costs of 10%.

[55] US Department of Energy Rulemaking Docket for Energy Conservation Standard for Room Air Conditioners, 2020. *https://www.regulations.gov/docket/EERE-2014-BT-STD-0059/document*

End-use	Assumptions for estimating cost
	• One caveat to this measure is that safety standards and building codes need to be updated to allow alternative ultra-low-GWP refrigerants.
Residential HP space conditioner (New) – 150 GWP limit	• Baseline cost data is from the HFC regulation.[51] • It is assumed that the cost to transition from 750 GWP refrigerants to 150 GWP refrigerants will be similar to the cost to transition from the higher-GWP refrigerants currently in use to the impending existing requirement of 750 GWP, effective 2025. • The cost for the first transition is ~5%.[51] To be conservative, it is assumed that there will be a ~10% incremental cost for the second transition.
Commercial HP space conditioner (New) – 150 GWP limit	• Baseline cost data is from the HFC regulation.[51] The cost of a typical system is assumed to be the average of the cost of a small-medium and large commercial AC. • An incremental cost of 10% is associated with this measure, based on the same rationale as the residential 150 GWP requirement for space conditioning HPs.
Commercial and Residential HP Space Conditioner (Existing – BE switch out)	• It is assumed that if HPs are installed as part of larger BE efforts to transition away from fossil gas, the incremental cost of installing a 150 GWP HP will be 0. • If an existing operational higher-GWP HP is switched out for a lower-GWP HP, it is assumed that the added incremental cost will be 100% based on the cost of new equipment. • It is challenging to determine the proportion of forced retrofits occurring due to BE efforts and those occurring to reduce refrigerant emissions. Thus, a cost range of 0-100 is used.
Commercial Ref. > 50 lb (New) – 150 GWP Limit	• No incremental costs are assumed since this is an existing regulatory requirement.
Commercial Ref. > 50 lb (Existing) – 1400 GWP limit	• No incremental costs are assumed since this closely mirrors an existing regulatory requirement.

End-use	Assumptions for estimating cost
Commercial Ref. > 50 lb (New) – 1 GWP limit	• A cost of 0 is assumed for this measure because all commercially available alternatives with GWP < 150 have a GWP of ~1 and GWP < 150 is an existing regulatory requirement.
Commercial Ref. > 50 lb (Existing) – 1 GWP Limit	• Baseline cost data is obtained from the HFC regulation.[51] • A 50% incremental cost of is assumed for this measure because to an ultra-low GWP system is not a drop in for an existing HFC system. A 100% incremental cost is not assumed because the national HFC phasedown will impact cost of HFC refrigerants and substantial repairs to HFC systems are common, which can be avoided with a system replacement.
Commercial Ref. < 50 lb (New) – 1 GWP Limit	• Baseline cost data is assumed to be 50% of the cost for larger systems that are 50-200 lbs in size, as noted in documentation for the HFC regulation.[51] • Since this is an evolving market, on the upper end, a 50% incremental cost is assumed. • On the lower end, an incremental cost of 10% is assumed because there are existing technologies, i.e., propane systems, many at cost parity with conventional HFC units.
Commercial Ref. < 50 lb (Existing)* - 1400 GWP Limit	• Baseline cost for retrofits to 1400 GWP refrigerants is obtained from the HFC regulation and is $45/lb of refrigerant retrofitted. [51] It is assumed that < 50 lb systems have an average charge of 25 lb from the F-gas inventory. • It is assumed that the incremental cost of a refrigerant retrofit will be 50% higher than the cost of inaction because the national HFC phasedown will be in effect and the cost of HFCs is expected to be considerably higher in 2035 due to limited availability.
Commercial Ref. < 50 lb (Existing)** - 1 GWP Limit	• Baseline cost data for this measure is assumed to be the same as the above measure requiring a GWP of 1 by 2025 for < 50 lb systems. • A 50% incremental cost is assumed for this measure, for the same reasons as listed above for replacing existing systems > 50 lbs.
Industrial Process Refrigeration + Cold Storage (New)	• No incremental costs are assumed since this is an existing regulatory requirement.

End-use	Assumptions for estimating cost
Industrial Process Refrigeration + Cold Storage (New)	• A cost of 0 is assumed for this measure because all commercially available alternatives with GWP < 150 have a GWP of ~1 and GWP < 150 is an existing regulatory requirement.
Industrial Process Refrigeration + Cold Storage (Existing)	• Baseline cost data for commercial refrigeration systems is obtained from the HFC regulation.[51] • Given the incompatibility of conventional technologies and new ultra-low-GWP technologies, it is assumed that the incremental cost of installing an ultra-low-GWP in an existing facility will be substantial, i.e., between 50-100%. The reasoning is similar to that for replacing other types of existing refrigeration systems.
Chillers (AC) (New) – 750 GWP Limit	• No incremental costs are assumed since this is an existing regulatory requirement.
Chillers (AC) (New) – 1 GWP Limit	• Incremental cost data for chillers is from studies conducted to support the U.S. EPA SNAP rulemaking.[56] • It is assumed that the incremental costs will be about 20% above baseline, which is similar to the incremental cost for < 150 GWP refrigeration systems compared to HFC-based systems.[51]
Chillers (AC) (Existing) – 1 GWP Limit	• Baseline cost data for an AC chiller is assumed to be same as the cost of a food retail refrigeration system.[51] Capacities/design complexities are assumed to be similar and hence, cost is assumed to be similar. • An incremental cost range of 50-100% is assumed for this measure for the same reasons as replacing other types of existing refrigeration systems.
Chillers (IPR) (New) – 750-2200 GWP Limit	• No incremental costs are assumed since this is an existing regulatory requirement.

[56] ICF International, "Economic Impact Screening Analysis for Regulatory Changes to the Listing Status of High-GWP Alternatives used in Refrigeration and Air Conditioning, Foams, and Fire Suppression," September 2016.

End-use	Assumptions for estimating cost
Chillers (IPR) (New) – 1 GWP Limit	• Baseline cost data for IPR chillers is assumed to be same as the cost of an IPR refrigeration system. [51] Capacities/design complexities are assumed to be similar and hence, cost is assumed to be similar. • It is assumed that the incremental costs will be about 20% above baseline, which is similar to the incremental cost for < 150 GWP refrigeration systems compared to HFC-based systems.[51]
Chillers (IRP) (Existing) – 1 GWP Limit	• Baseline cost data for IPR chillers is assumed to be same as the cost of an IPR refrigeration system. [51] • An incremental cost range of 50-100% is assumed for this measure for the same reasons as replacing other types of existing refrigeration systems.
MVAC Gasoline – light duty (New)	• Currently, 85% of new light duty (LD) vehicles use HFO-1234yf with GWP~1.[57] It is expected that in the coming few years 100% of new gasoline cars will use HFO-1234yf. • Because most new cars already use HFOs, it is assumed that this measure will have an incremental cost of 0.
MVAC Electric – light duty (New)	• Electric vehicles use heat pumps and the most promising alternative that has been identified is R-152a with a GWP of 124. Redesigning MVAC to use R-152a is estimated to have an incremental cost of 10% compared to the baseline cost of the AC equipment.[58] • Baseline cost of new AC equipment is assumed to be $1,250, assuming labor and installation are half of the total cost of a new AC, which is $2,500.[59]
MVAC Gasoline & Electric – heavy duty and other (New)	• It is assumed that AC for all heavy duty (HD) vehicles – either gasoline or electric-powered – will use the same refrigerant, i.e., R-152a or a similar refrigerant. It is estimated to have an incremental cost of 10% compared to the baseline cost of the AC equipment.[60]

[57] The 2021 EPA Automotive Trends Report, page 89 (https://www.epa.gov/automotive-trends/download-automotive-trends-report#Full%20Report)
[58] Stakeholder feedback received by CARB during the development of various HFC regulations.
[59] MotorVerso Article on "Auto air conditioning repair costs – How much are they for a fix?" *https://www.motorverso.com/auto-air-conditioning-repair-costs/#costs*
[60] Stakeholder feedback received by CARB during the development of various HFC regulations.

End-use	Assumptions for estimating cost
	• The baseline cost of AC equipment used in HD vehicles, without labor and installation, is assumed to be similar to the cost of AC in LD vehicles. To be conservative, the upper end of the cost range of $2,000 is used for AC equipment.[61]
Transport Refrigerated Unit (TRU) (New) – 2200 GWP Limit	• No incremental costs are assumed since this is an existing (proposed) regulatory requirement, effective 2023.
Transport Refrigerated Unit (TRU) (New) – 1 GWP Limit	• Baseline cost of an electric TRU (an impending regulatory requirement), is obtained from the TRU regulatory documents and is estimated at $45,000. [62] • It is assumed that the cost of an ultra-low-GWP TRU will be 50% higher than the baseline cost of a higher-GWP unit. CO_2-based ultra-low-GWP technologies for TRUs have been introduced in Europe[63], however, they are still in development in the U.S.
Transport Refrigerated Unit (TRU) (Existing) – 2200 GWP limit	• The cost of retrofitting an existing R-404A TRU unit with a lower-GWP unit is estimated to be the same as the added costs associated with a new R-452A unit. Retrofit costs are obtained from the TRU regulation and estimated to be between $38-100 higher depending on the type of TRU.[64]

[61] MotorVerso Article on "Auto air conditioning repair costs – How much are they for a fix?" *https://www.motorverso.com/auto-air-conditioning-repair-costs/#costs*
[62] CARB TRU Regulation Initial Statement of Reasons. July 2021. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/rulemaking/tru2021/isor.pdf*
[63] Freight Waves, "Carrier Transicold reefer unit uses CO2 as refrigerant," October 9, 2013. *https://www.freightwaves.com/news/carrier-transicold-reefer-unit-uses-co2-as-refrigerant*
[64] CARB TRU Regulation Initial Statement of Reasons. July 2021. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/rulemaking/tru2021/isor.pdf*

End-use	Assumptions for estimating cost
National HFC Phasedown – "Best-case scenario"	• In 2019, the Kigali Amendment to the Montreal Protocol, an international HFC phasedown, went into effect. While the US has not ratified the Amendment, Congress adopted the American Innovation and Manufacturing Act (AIM Act) in December 2020, which closely mirrors the HFC phasedown in the Kigali Amendment.[65] • Due to the lag in emission reductions from a phasedown in production and consumption of HFCs, some level of uncertainty is inherent in any phasedown or phaseout. It is common practice to develop an average phasedown scenario based on a best and worst scenario for a phasedown.[66]

[65] United States, Congress. Public Law 116–260 — Dec. 27, 2020. Consolidated Appropriations Act, 2021, pp. 2255-71. *U.S. Government Publishing Office*, *https://www.govinfo.gov/content/pkg/PLAW-116publ260/pdf/PLAW-116publ260.pdf*.
[66] https://ww2.arb.ca.gov/sites/default/files/2018-12/CARB-Potential-Impact-of-the-Kigali-Amendment-on-HFC-Emissions-Final-Dec-15-2017.pdf

Biomass-Energy Supply

Biomass-energy supply estimates represent the share of available feedstock that could be economically and beneficially[67] used to displace fossil fuels, rather than gross resource potentials. Assumptions and information used to estimate the supply likely available for energy use in California, are described for each resource: agricultural residues; biomethane from landfills, wastewater treatment facilities, landfill-diverted organic waste, and dairy digesters; forest-derived residues; and supplies of fats, oils and greases. These estimates exclude sugar and starch feedstocks, such as corn and sugarcane which are presently used to produce ethanol.

Agricultural Residues

Agricultural residues available for use in California were estimated using two primary data sources: (1) The U.S. Department of Energy Billion Ton Report (BTS),[68] and (2) the UC Davis Biomass Collaborative's (BMC) assessment of biomass resources in California.[69] The BMC estimates are specific to California, but the report does not contain a specific supply curve associated with bringing residues to market. As such, the feedstock costs found in the BTS were assumed to be representative of costs in California, and cellulosic and woody biomass price bins were used to estimate feedstock costs for residues available in California. The fraction of residues was limited to the quantity with a biomethane production cost below $34 per MMBTU (2021 dollars). The threshold of $34 per MMBTU is likely the upper cost limit for using agricultural residues because lower-carbon fuels, such as hydrogen production from electrolysis, can likely be produced at these costs.[70] This threshold also exceeds most electric resistance heating strategies, and would fall within the Tier 3 approval letter provisions for biomethane procurement proposed by the CPUC.[71,72] This approach results in an estimated 4.3 million bone dry tons of agricultural residue that may be directed toward energy, as shown in Table H-31. This value is not expected to change significantly across scenarios or over time.

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[67] This includes estimating supply curves and the costs to utilize biomass resources for energy relative to other energy options. The social costs of criteria emissions damages affiliated with leaving forestry residues on-site, burning them on-site, or mobilizing them were used to better understand which residue-collection areas were likely to yield social benefits if mobilized. Appendix I contains more detail relating to forestry residues.

[68] *https://bioenergykdf.net/billionton2016/overview*

[69] *https://biomass.ucdavis.edu/wp-content/uploads/CA_Biomass_Resource_2013Data_CBC_Task3_DRAFT.pdf*

[70] $3.74 per kg H_2 is approximately $33/MMBtu. *https://www.nrel.gov/docs/fy12osti/52640.pdf*

[71] *https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf*

[72] *https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M386/K579/386579735.PDF*

Table H-31. Estimated recoverable agricultural residue (short dry tons) relative to production cost ($/MMBTU)

Cost of Production ($/MMBTU)	***$12***	***$15***	***$17***	***$19***	***$22***	***$24***	***$27***	***$29***	***$31***	***$34***
Cumulative Feedstock (tons)	0.0	0.0	0.1	0.1	0.9	0.9	1.1	1.1	4.2	4.3

Landfill Gas and Wastewater Treatment

Available supply of biomethane from landfills with gas collection and control systems was projected using CARB's Annual GHG Inventory methodology for calculating landfill gas generation and recovery,[73] and aligns with potential supply estimates from the University of California-Davis.[74] All alternative scenarios assume that no more than 6 million short tons of organic waste is disposed in 2025 and thereafter, reflecting achievement of the 75% organic waste disposal reduction target.

Biomethane generated from anaerobic digestion of sludge at municipal and industrial wastewater treatment facilities in California was estimated using the Annual GHG Inventory data for 2019, and aligns with potential supply estimates from the University of California-Davis.[75] Biomethane supply from municipal treatment is assumed to grow in proportion to population in both the reference and alternative scenarios.

Landfill-Diverted Organic Waste

To determine the quantities of biomethane expected to be available from anaerobic digestion (AD) of landfill-diverted organic waste, CARB relied on CalRecycle's 2018 Waste Characterization Study,[76] and Analysis of the Progress Toward the SB 1383 Waste Reduction Goals.[77] In all scenarios, AD yields of 2 to 2.4 MMBtu/short wet ton of organic waste is assumed.[78,79]

The Reference Scenario is based on the existing and planned future AD capacity (including co-digestion in existing digesters at wastewater treatment plants) in 2025.[80]

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[73] *https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2014/ghg_inventory_00-14_technical_support document.pdf*
[74] *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/13-307.pdf*
[75] *Ibid.*
[76] https://www2.calrecycle.ca.gov/Publications/Details/1666
[77] https://www2.calrecycle.ca.gov/Publications/Details/1693
[78] *https://www.waterboards.ca.gov/climate/docs/co_digestion/final_co_digestion_capacity_in_california appendices_only.pdf*
[79] https://www.calrecycle.ca.gov/organics/slcp
[80] *https://www2.calrecycle.ca.gov/Publications/Details/1693*. In addition to CalRecycle's estimate for 2025, CARB staff assumes moderate continued growth from 2025-2030 of 0.2 million tons/y from privately-funded AD projects leveraging incentive programs including LCFS, BioMAT, and RFS.

From 2025 to 2030, AD capacity is assumed to continue to grow by 0.2 million short tons per year, through private investment in response to existing incentives; beyond 2030, AD capacity increases more slowly, commensurate with growth in waste generation (proportional to population).[81] In addition, few non-combustion thermal facilities are expected to be operational by 2025 to produce fuels from dry, cellulosic wastes that are not suitable for AD. CARB assumed that 0.3 million tons of capacity will be available in the near-term.

All alternatives assume that the 75% organic waste disposal reduction target is met by 2025. For Alternative 1, no increase in AD is assumed beyond the existing, planned, and funded projects expected to become operational in the near term. The disposal reduction target is achieved by relying further on non-energy strategies such as composting. Alternatives 2 through 4 require more rapid growth in both stand-alone anaerobic digestion (3 million short wet tons) and co-digestion (2.4 million short wet tons). Post-2025, AD increases with growth in waste generation (proportional to population) to maintain the 75% disposal reduction. The expected capacity for diversion of landfill-diverted organic wastes to energy use for each scenario are shown in Table H-32.

Table H-32. Estimated capacity to process landfill-diverted organic waste for energy use

Scenario	Million Wet Tons					
Year	2020	2025	2030	2035	2040	2045
Reference	0.7	2.0	3.0	3.1	3.1	3.1
Alternative 1	0.7	1.8	1.8	1.8	1.8	1.8
Alternatives 2 through 4	0.7	5.5	5.5	5.6	5.7	5.8

Biomethane from California Dairies

Estimates for biomethane potential associated with California dairies were generated using supply curves from Jaffe et al. (2016).[82] Methane reduction projections were calibrated with the dairy supply curves to estimate the potential biomethane that might be captured based on the number of dairy digester projects built for each reference case.

Forest Residues

The Reference Scenario for forest residues was created using non-merchantable, mobilizable residue estimates from California land treatment activities for historic

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[81] Department of Finance. P-1A: State Population Projections (2010-2060). Accessed 10/21/2021 *https://www.dof.ca.gov/Forecasting/Demographics/Projections/*

[82] *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/13-307.pdf*

treatments. For the alternative scenarios, the amount of treatable land was scaled to 1 million acres annually.

Mobilizable biomass estimates were derived using the results from the C-BREC modeling work. More detail on estimating forestry residue quantities can be found in Appendix I. The C-BREC model output provides high-resolution estimates for mobilizable biomass per acre of land treated. The NWL modeling staff at CARB provided estimates for the area of land likely to be treated by ownership type and ecological unit[83] type for the reference case. Mobilizable yields for Alternative 4 were scaled to be consistent with achieving the goal of treating 1 million acres of forested and wildland in California each year, and no assumptions about using residues in non-energy markets were made. For Alternatives 1, 2, and the Proposed Scenario, only additional residue that may be mobilized at carbon prices above $50 per metric ton was allocated for use as energy.[84] Allocation for these Alternatives reflect using biomass for energy only for hard-to-decarbonize industries, and preferentially using biomass residues for use in durable wood products and non-energy applications.

Fats, Oils, and Greases

This category of feedstocks includes both primary or virgin (e.g., plant-derived oils) and secondary (e.g., waste and by-product oils including rendered animal fats, used cooking oils and trap grease) lipids. The current supply of fats, oils, and greases (FOG) for use as energy in California is large due to the global waste oil and virgin oil markets that have developed in response to biofuel markets.

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[83] Ecological units represent landscapes that have similar vegetation, growing conditions, site qualities, climates, soil conditions, and disturbance regimes. Ecological units were developed using the following process: Every "HUC12" watershed unit in California was classified by three biogeographic properties: dominate existing vegetation order, aridity, and ecoregion. The dominant existing vegetation type, average aridity, and dominate ecoregion was then calculated for each HUC12. These three variables for each HUC12 was then used to classify each HUC12 watershed. This classification scheme resulted in 228 unique classifications across California. These classifications were then either removed, because they will not be modeled in this current effort (developed, non-vegetated, sparsely vegetated, and annual crop lands), or grouped together to derive larger ecological units.

[84] Energy production cost estimates were derived using U.S. Department of Energy models. Carbon benefits from using biomass as an energy resource were assumed to be 65 gCO_2e/MJ of conventional fuel displaced. At higher carbon prices a larger amount of biomass residue was estimated to be socially beneficial to mobilize. A large fraction of biomass residue was socially beneficial to mobilize at low carbon prices due to benefits from avoiding criteria emissions. More detail is provided in Appendix I.

2019 supply estimates for U.S.-sourced waste oils[85] were used alongside volumes of virgin oils[86] currently used for biofuel production in the U.S. to estimate the current total available supply of FOGs. Available waste-oil quantities were projected to decrease through 2045, due to increased competition for the available supply of waste oils, until they represent a California population-weighted share of supply as shown in Table H-33.

Table H-33. Estimated supply of fats, oils, and greases available to California by year

Year	2020	2025	2030	2035	2040	2045
Waste Oil (Million Tons)	3.7	2.4	1.6	1	0.7	0.7
Virgin Oil (Million Tons)	6.0	6.2	7.1	7.6	8.0	8.0

California's current consumption of biomass-based diesel is around 1 billion gallons annually, with approximately 75% of that demand now being met through renewable diesel.[87] Trends indicate that renewable diesel is likely to be the primary biomass-derived diesel fuel in the future. Renewable diesel consumption in California has been limited by the existing production capacity from renewable diesel facilities.

Projections for the total volume of FOGs that could be used for energy in California were constrained to reflect only the announced capacity and potential capacity expansions for renewable diesel facilities that are planned to be operational in California. Current announcements suggest that 1.1 billion gallons of renewable diesel will be produced within California by 2025, with anticipated expansions potentially adding another 1.1 billion gallons of capacity.[88] Taken together, this analysis assumes total available supply of renewable diesel from FOGs for use in California to be 2.2 billion gallons. This value was held constant through 2045.

[85] Waste oils were derived from agricultural head counts: *https://www.fao.org/faostat/en/*. Yields are approximated as: 65.84 lbs. edible tallow per head, 109.18 lbs. inedible tallow per head, 3.10 lbs. lard per head, 11.83 lbs. choice white grease per head, 0.26 lbs. poultry fat per head, and 8.82 lbs. tallow per head sheep. Yields are taken from Swisher (2017) "Market Report" Render Magazine. Fat, Oil, and Grease is assumed to convert to 255 gallons of renewable diesel per ton.

[86] *https://www.eia.gov/biofuels/biodiesel/production/biodiesel.pdf* and *https://www.nass.usda.gov/Publications/Todays_Reports/reports/cafoan20.pdf*

[87] *https://ww3.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm*

[88] Announcements concerning potential capacity expansion are being tracked and aggregated by the Argus Media Group and released as part of their Renewable Diesel Refinery Database

Air Quality and Health Analysis

This section provides an overview of the modeling to support evaluation of air quality and health benefits associated with the Proposed Scenario and alternatives. This work was conducted by researchers in the Advanced Power and Energy Program at the University of California, Irvine. This section of the appendix describes the approach, including modeling caveats. It also presents some additional results that were not included in Chapter 3.

Approach

An integrated modeling approach is used to characterize and quantify the air quality and public health impacts of the four alternative Scoping Plan scenarios relative to a business-as-usual Reference scenario to provide relative insight into the co-benefits that each scenario achieves. Using output from the PATHWAYS model, spatially and temporally resolved characterizations of pollutant emissions are developed for all sectors and sources in California including stationary, area, and mobile source emissions. The emissions are projected to 2045 from a detailed base year CARB pollutant emissions inventory (2020 CARB v0018) and spatially and temporally resolved using the Sparse Matrix Operator Kernels Emissions (SMOKE v4.7) model. Next, emission changes are translated into impacts on atmospheric pollution levels, including ground-level ozone and fine particulate matter ($PM_{2.5}$), via an advanced photochemical air quality model called the Community Multiscale Air Quality (CMAQ v5.3.2) model that accounts for atmospheric chemistry and transport. Given the highly computational nature of CMAQ and the number of scenarios considered, an episodic air quality modeling approach is used including the evaluation of the differences in ground-level ozone and $PM_{2.5}$ for the months of July and January in 2045 in the alternative scenarios relative to the Reference. Air quality changes are then used to conduct a health impact assessment using the Environmental Benefits Mapping and Analysis Program - Community Edition (BenMAP v1.5.8) which provides a quantitative estimate of the incidence and value of avoided harmful health outcomes associated with air pollution in each scenario. Finally, the health impact results are analyzed through an environmental justice framework to quantify the benefits that occur specifically within socially and economically disadvantaged communities (DAC) that are identified using CalEnviroScreen 4.0. Table H-34 provides an overview of the major models and data sources used in the assessment.

Table H-34. Overview of the key modeling tools utilized to conduct the air quality and public health benefits assessment

	Model
Base Year Inventory	2020 CARB v0018
Emissions Processing	SMOKE v4.7 and ESTA
Air Quality Model	CMAQ v5.3.2
Health Impacts	BenMAP v1.5.8
DAC Identification	CalEnviroScreen 4.0

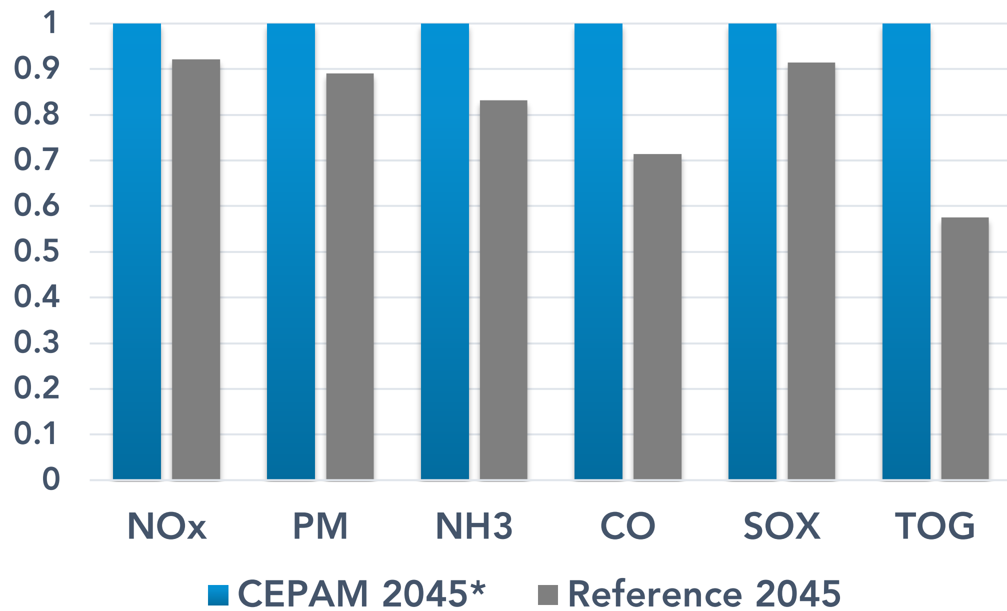
Emissions

The baseline pollutant emissions represent a highly detailed inventory developed by CARB (CARB 2020 v0018) which includes total emissions by sector and source as well as spatial and temporal information regarding source activity. The emissions are then grown and controlled to 2045 using output from the PATHWAYS model for technologies, fuels, and energy demand by AB 32 GHG Inventory sector. Additionally, data from various sources is to account for changes in emission rates, control factors, and others including EMFAC 2021 v1.0.1[89] for on-road vehicles, OFFROAD2021[90] for other transportation sectors, and the CARB California Emissions Projection Analysis Model (CEPAM) 2019 v1.03 for stationary sources.[91] CEPAM was developed to support State Implementation Plan development and evaluation and to support air quality modeling efforts. CEPAM provides emission forecasts for mobile, point and area sources using the most current growth and control data and emission estimates from EMFAC and OFFROAD to provide a comprehensive emission inventory. As a benchmarking step for this project, the emission projections by sector and source for the Reference are compared to those from CEPAM. While the two projections are not

[89] CARB, "EMFAC2021 Volume III Technical Document," Sacramento, CA, 2021. [Online]. Available: https://ww2.arb.ca.gov/sites/default/files/2021-08/emfac2021_technical_documentation_april2021.pdf
[90] CARB, "OFFROAD2021 Web Query Tool," 2021. https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road (accessed Jan. 01, 2022).
[91] California Air Resources Board, "California Emissions Projection Analysis Model (CEPAM2019v1.03)," 2022. https://ww2.arb.ca.gov/applications/cepam2019v103-standard-emission-tool

based on the same scenario and thus not directly comparable, CEPAM does provide a useful benchmark as both are broadly representative of a business-as-usual trajectory for emissions in California to 2045. As shown in Figure H-3, total pollutant emissions in 2045 for the Reference Scenario are conservative (i.e., lower) than those projected by CEPAM, which therefore provides a conservative estimate for the emission reductions (and subsequent air quality and health impacts) achieved by the Proposed Scenario and alternatives.

Figure H-3. Normalized 2045 pollutant emissions from CEPAM2019 v1.03 projections (blue) and the Reference Scenario (grey)



The pollutant emissions inventory is then processed into air quality model-ready format using the Sparse Matrix Operator Kernel Emissions model (SMOKEv4.7) including resolving the location and timing of the emissions to correspond with the sources that are responsible for them, e.g., the location of refineries, the locations of residential and commercial buildings, the locations of major roadways and the traffic patterns for vehicles.[92] Onroad vehicle emissions are spatially resolved to the locations of vehicle activity using the Emissions Spatial and Temporal Allocator (ESTA) model developed by CARB.[93]

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[92] "SMOKE v4.0 User's Manual," Community Modeling and Analysis System . Available: https://www.cmascenter.org/smoke/documentation/4.0/manual_smokev40.pdf , 2016.
[93] CARB, "ESTA Documentation," 2022. https://github.com/mmb-carb/ESTA_Documentation (accessed Mar. 09, 2022).

Emissions Modeling Caveats

The following section provides major assumptions and caveats associated with the emissions modeling that should be considered when interpreting the results.

PATHWAYS output is at the state-level which requires the emissions projection to be a state-wide average. Therefore, the approach does not allow for the resolution at the regional or sub-regional level, e.g., PATHWAYS output for the refinery sector is reported for California as a whole and emission changes are applied equally across the existing refinery fleet. However, it should be noted that the baseline CARB emissions inventory does have highly detailed data for each sector and source and solely the projection to 2045 is a state-wide average.

Only existing sources/facilities are included, and no major functional changes to existing sources are assumed. Given the uncertainty associated with the siting and activity of novel emission sources, only existing sources of emissions are included in the assessment.

Air Quality

Atmospheric chemistry and transport are simulated using the Community Multi-scale Air Quality model (CMAQ, v5.3.2) to provide a comprehensive understanding of how pollutant concentrations are impacted, accounting for both primary (emitted) and secondary (formed) species including ground-level ozone and $PM_{2.5}$.[94] CMAQ is developed by US EPA and is widely used for AQ assessment purposes, including for various research needs such as assessing the air quality impacts of emission inventories,[95] energy sectors integrating alternative technologies in energy systems,[96] regulatory compliance[97] and research associated with tropospheric ozone, PM, acid deposition, and visibility.[98,99] The use of CMAQ is particularly important in assessing air quality as a significant portion of the pollution impacting California populations is secondary and forms in the atmosphere, e.g., depending on season and region

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[94] U.S. EPA, "Community Multiscale Air Quality Modeling System (CMAQ)," 2022. https://www.epa.gov/cmaq/latest-version-cmaqv533 (accessed Sep. 03, 2021).

[95] S. Zhu, M. Mac Kinnon, B. P. Shaffer, G. S. Samuelsen, J. Brouwer, and D. Dabdub, "An uncertainty for clean air: Air quality modeling implications of underestimating VOC emissions in urban inventories," *Atmos. Environ.*, vol. 211, pp. 256–267, 2019.

[96] M. Mac Kinnon, B. Shaffer, M. Carreras-Sospedra, D. Dabdub, G. S. Samuelsen, and J. Brouwer, "Air quality impacts of fuel cell electric hydrogen vehicles with high levels of renewable power generation," *Int. J. Hydrogen Energy*, vol. 41, no. 38, pp. 16592–16603, 2016.

[97] S. Samuelsen, S. Zhu, M. Mac Kinnon, O. K. Yang, D. Dabdub, and J. Brouwer, "An Episodic Assessment of Vehicle Emission Regulations on Saving Lives in California," *Environ. Sci. Technol.*, 2020.

[98] H. O. T. Pye *et al.*, "Anthropogenic enhancements to production of highly oxygenated molecules from autoxidation," *Proc. Natl. Acad. Sci.*, vol. 116, no. 14, pp. 6641–6646, 2019.

[99] K. W. Appel *et al.*, "The Community Multiscale Air Quality (CMAQ) model versions 5.3 and 5.3. 1: system updates and evaluation," *Geosci. Model Dev.*, vol. 14, no. 5, pp. 2867–2897, 2021.

secondary $PM_{2.5}$ can comprise 40-60% of the total atmospheric $PM_{2.5}$ burden.[100] For this work, the SAPRC-07 chemical mechanism[101] is utilized to model gas-phase chemistry, and AERO6 module[102] is used to calculate aerosol dynamics. The simulation domain is the same as the Reference Scenario[103] with a 4 km x 4 km horizontal resolution that covers all of California. The Advanced Research Weather Research and Forecasting Model (WRF-ARW, 3.9.1)[104] is used to downscale meteorological conditions from the NCEP North American Regional Reanalysis dataset.[105] The boundary conditions are generated using the Community Atmosphere Model with Chemistry v2.1 (CESM2.1/CAM-chem).[106] Biogenic emissions, including those from vegetation and soil, are generated using the Model of Emissions of Gases and Aerosols from Nature (MEGANv2.1).[107] Although simulations are conducted for the year 2045, the boundary and meteorological conditions are held constant with the 2020 base emission inventory year to ensure the impacts result only from changes in anthropogenic emissions associated with the measures in the Proposed Scenario and alternatives.

Two simulation periods are conducted to capture the effect of seasonal variation in meteorology and emissions concentrations including a summer month (July) and winter month (January). July is selected as it includes conditions conducive to high ozone and $PM_{2.5}$ concentrations, including high surface temperatures, an abundance of sunlight, lack of natural scavengers, and the presence of inversion layers.[108] Similarly, the month of January is included as it is associated with high levels of $PM_{2.5}$ in some regions of California including the South Coast Air Basin (SoCAB) and the Central Valley. For both seasons, the first five days of the simulation period are considered model spin up and excluded from the analysis. The CMAQ output has been validated

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[100] S. Hasheminassab, N. Daher, A. Saffari, D. Wang, B. D. Ostro, and C. Sioutas, "Spatial and temporal variability of sources of ambient fine particulate matter (PM 2.5) in California," *Atmos. Chem. Phys.*, vol. 14, no. 22, pp. 12085–12097, 2014.

[101] W. P. L. Carter, "Development of the SAPRC-07 chemical mechanism," *Atmos. Environ.*, vol. 44, no. 40, pp. 5324–5335, 2010.

[102] H. O. T. Pye *et al.*, "On the implications of aerosol liquid water and phase separation for organic aerosol mass," *Atmos. Chem. Phys.*, vol. 17, no. 1, pp. 343–369, 2017, doi: 10.5194/acp-17-343-2017.

[103] S. Zhu, J. R. Horne, M. Mac Kinnon, G. S. Samuelsen, and D. Dabdub, "Comprehensively assessing the drivers of future air quality in California," *Environ. Int.*, vol. 125, pp. 386–398, 2019.

[104] W. C. Skamarock *et al.*, "A Description of the Advanced Research WRF Version 3," *Tech. Rep.*, no. June, p. 113, 2008, doi: 10.5065/D6DZ069T.

[105] NOAA, "NCEP North American Regional Reanalysis: NARR," 2022. https://psl.noaa.gov/data/gridded/data.narr.html (accessed Jan. 15, 2022).

[106] G. Danabasoglu et al., "The community earth system model version 2 (CESM2)," J. Adv. Model. Earth Syst., vol. 12, no. 2, p. e2019MS001916, 2020.

[107] A. B. Guenther *et al.*, "The Model of Emissions of Gases and Aerosols from Nature version 2.1 (MEGAN2. 1): an extended and updated framework for modeling biogenic emissions," 2012.

[108] M. Carreras-Sospedra, D. Dabdub, M. Rodriguez, and J. Brouwer, "Air quality modeling in the south coast air basin of California: What do the numbers really mean?," *J. Air Waste Manage. Assoc.*, vol. 56, no. 8, pp. 1184–1195, 2006.

for the 2020 base year using observational data from the U.S. EPA's Air Quality System[109] and found to be within the statistical parameters established by the scientific community for acceptable model performance.[110]

The two pollutants considered to assess air quality and health are $PM_{2.5}$ and tropospheric ozone as many regions of California experience ambient levels in excess of State and Federal health-based standards[111] and both are well known to be associated with health consequences in exposed populations and commonly included in similar health impact assessments.[112,113,114] For consistency with ambient air quality standards, ground-level concentrations are reported as maximum daily 8-h average ozone (MD8H) and 24-h average $PM_{2.5}$.

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[109] O. US EPA, "Air Quality System (AQS)," 2019.
[110] C. Emery, Z. Liu, A. G. Russell, M. T. Odman, G. Yarwood, and N. Kumar, "Recommendations on statistics and benchmarks to assess photochemical model performance," *J. Air Waste Manage. Assoc.*, vol. 67, no. 5, pp. 582–598, Apr. 2017, doi: 10.1080/10962247.2016.1265027.
[111] CARB, "Area Designation Maps / State and National. California Air Resources Board," 2017.
[112] D. W. Dockery *et al.*, "An association between air pollution and mortality in six US cities," *N. Engl. J. Med.*, vol. 329, no. 24, pp. 1753–1759, 1993.
[113] M. Jerrett *et al.*, "Long-term ozone exposure and mortality," *N. Engl. J. Med.*, vol. 360, no. 11, pp. 1085–1095, 2009.
[114] C. A. Pope III and D. W. Dockery, "Health effects of fine particulate air pollution: lines that connect," *J. Air Waste Manage. Assoc.*, vol. 56, no. 6, pp. 709–742, 2006.

Table H-35. Overview of the air quality modeling tools and sources of data inputs

Model	
Base Year Inventory	2020 CARB v0018
Emissions Processing	SMOKE v4.7 and ESTA
Air Quality Model	CMAQ v5.3.2
Chemical Mechanism	SAPRC-07 and AERO6
Biogenic Emissions	MEGAN v2.1
Meteorological Files	WRF-ARW v3.9.1
Boundary Conditions	CESM v2.1/CAM-chem

Air Quality Modeling Caveats

The following section provides major assumptions and caveats associated with the air quality assessment that should be considered when interpreting the results.

Episodic modeling provides insight into the maximum impacts on air quality the Proposed Scenario and alternatives may have but does not provide a comprehensive understanding of the air quality impacts. Due to the selection of modeling periods coinciding with high pollutant formation periods, the pollutant differences and the corresponding health impacts are also highest during those periods and may not be as large in other months. Therefore, the results of both the air quality and health benefit assessments represent two distinct months and cannot be used to estimate other periods, e.g., multiplying to determine annual changes.

Meteorology and other factors including boundary conditions are held constant to the base year. The changes in air quality modeled here only account for changes in anthropogenic emissions (i.e., emissions from energy systems modeled in PATHWAYS) and all other CMAQ inputs are held constant with the base year. Therefore, the results do not account for climate-impacted meteorology or related drivers of future air pollution. This is done for practical and analytical reasons including to ensure all reported impacts occur as a result of changes in pollutant emissions from the actions within the Proposed Scenario and alternatives.

The impacts of wildfires are not included in this assessment. Emissions from wildfires contribute significantly to degraded air quality concerns in California. However, with similarity to the reasoning for other non-anthropogenic air pollution drivers, wildfire emissions are not included in the episodic modeling in order to make certain that the impacts reported in the assessment are solely a result of the Draft Scoping Plan actions related to anthropogenic emissions from energy systems. However, it should be noted that an assessment of wildfire emissions impacts is provided separately in Appendix I (NWL Technical Support Document).

Health Impacts

Epidemiological studies have shown that reducing air pollution exposure results in reductions in the incidence of harmful health endpoints. The Benefits Mapping and Analysis Program—Community Edition version 1.5.8 (BenMAP) from the U.S. EPA is used to quantify and value the public health benefits that result in each scenario.[115] BenMAP allows for the quantification of the avoided incidence and economic value of health endpoints that result from differences in air pollution concentrations. Population projections to 2045 at the census tract level were obtained from GeoLytics.[116] The endpoints selected for the health analysis and corresponding Reference Scenario for the concentration-response function used to quantify reductions in their incidence due to reduced exposure to $PM_{2.5}$ and ozone are shown in Table H-36 and Table H-37. The selection of inputs, including concentration-response functions, baseline incidence rates, and valuation functions, generally follow those recommended by the U.S. EPA in the BenMAPv1.5.8 user's manual.[117] Additionally, the quantification of avoided incidence of premature mortality due to reduced short-term exposure to $PM_{2.5}$ is estimated using Atkinson et al. 2014[118] following methods used by the South Coast Air Quality Management District.[119] A value of statistical life of $8.7 million is used to quantify mortality risk reduction benefits as recommended by the U.S. EPA. The health benefits are quantified in 2015 dollars, and then converted and reported in 2021 dollars. Health impacts are quantified for the entire month of July and January, except

[115] U.S. EPA, "Environmental Benefits Mapping and Analysis Program - Community Edition," 2022.
[116] GeoLytics, "California demongraphic data," 2020.
[117] U.S. EPA, "Environmental Benefits Mapping and Analysis Program - Community Edition," 2022.
[118] R. W. Atkinson, S. Kang, H. R. Anderson, I. C. Mills, and H. A. Walton, "Epidemiological time series studies of PM2.5 and daily mortality and hospital admissions: A systematic review and meta-analysis," *Thorax*, vol. 69, no. 7, pp. 660–665, 2014, doi: 10.1136/thoraxjnl-2013-204492.
[119] E. Shen, A. Oliver, and S. Dabirian, "Final Socioeconomic Report ," South Coast Air Quality Management District. Available at: http://www.aqmd.gov/docs/default-source/clean-air-plans/socioeconomic-analysis/final/sociofinal_030817.pdf?sfvrsn=2 , 2017.

for the first five days of each month which are discarded as model spin-up. Impacts are estimated for avoided short-term exposure to ozone and $PM_{2.5}$ in July and $PM_{2.5}$ in January given that ozone concentrations are generally below health-based standards in winter and share an inverse relationship with precursor emissions which prevents useful conclusions from being made from the results. Finally, the estimated health savings are quantified specifically within census tracts that have been identified as DAC using the CalEnviroScreen 4.0 tool.[120] To provide insight into the regional patterns of health benefits within DAC, the results are reported for both California as a whole and broken down by air basin.

Table H-36. Health endpoints and their concentration-response function reference included in the BenMAP analysis for reduced exposure to ozone

Ozone Health Endpoints	Reference
Avoided Mortality	Huang et al. 2005
Emergency Room Visits, Respiratory	Barry et al. 2018
Hospital Admissions, Respiratory	Katsouyanni et al. 2009
Asthma Symptoms	Lewis et al. 2013
Incidence, Asthma Onset	Tetreault et al. 2016

[120] OEHHA, "CalEnviroScreen 4.0." https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40 (accessed Apr. 02, 2022).

Table H-37. Health endpoints and their concentration-response function reference included in the BenMAP analysis for reduced exposure to PM2.5

$PM_{2.5}$ Health Endpoints	Reference
Avoided Premature Mortality	Atkinson et al. 2014
Hospital Admissions, Alzheimer's Disease	Kioumourtzoglou et al. 2016
Hospital Admissions, Parkinson's Disease	Kioumourtzoglou et al. 2016
Incidence, Lung Cancer	Gharibvand et al. 2016
Incidence, Asthma Onset	Tetreault et al. 2016
Acute Myocardial Infarction, Nonfatal	Zanobetti et al. 2009
Asthma Symptoms	Rabinovitch et al. 2006
Hospital Admissions, Cardiovascular	Bell et al. 2015
Emergency Room Visits, Cardiovascular	Ostro et al. 2016
Hospital Admissions, Respiratory	Bell et al. 2015
Emergency Room Visits, Respiratory	Krall et al. 2016

Health Impact Assessment Caveats

The following section provides major assumptions and caveats associated with the health impact assessment that should be considered when interpreting the results.

The health benefits are quantified and reported for reduced short-term exposure to $PM_{2.5}$ and ozone for only two months in 2045 to support the goal of providing

metrics useful for the relative comparison between the Proposed Scenario and alternatives. Therefore, the results do not provide a comprehensive accounting of the health benefits the scenarios would achieve annually in 2045, or cumulatively over the entire Scoping Plan period. Further, though BenMAP can be used to estimate long-term health impacts such as those occurring from annual average $PM_{2.5}$ changes, impacts are reported here for short-term exposure to ozone and $PM_{2.5}$ as appropriate for the modeled episodes. It should be noted that the value of short-term exposure health benefits are significantly lower than those estimated for long-term exposure, and this should be considered when comparing the results to other studies.

The health savings are calculated with the same granularity as the air quality modeling results (i.e., 4 km x 4 km) and do not provide insight into local-scale impacts. The results can then be reasonably down-scaled to the census tract level, but cannot provide accurate insight into the impacts at more granular scales, e.g., neighborhood-level, fence-line impacts, etc.

Results

Emissions

The Proposed Scenario and alternatives achieve significant pollutant emission reductions in 2045 from the Reference Scenario due to the measures impacting technologies, fuels, and energy demands within AB 32 GHG Inventory sectors. Table H-38 provides the total reductions in NO_x, $PM_{2.5}$, and ROG for the Proposed Scenario and alternatives for January and July 2045 from the Reference Scenario. The total NO_x emissions for the 2020 base year inventory, the 2045 Reference Scenario, and 2045 Proposed Scenario and alternatives are shown in Figure H-4. Even under a business-as-usual trajectory, emissions are reduced from current levels by 26% in the 2045 Reference Scenario, demonstrating the impact of current regulations and trends in energy sectors. From the Reference Scenario, the four alternatives achieve reductions in NO_x ranging from approximately 90% in Alternative 1 to over 40% in Alternative 4. In 2045, NO_x reductions in Alternative 2 and the Proposed Scenario are similar in scale and are approximately 60% from the Reference Scenario.

Figure H-4. Total NO_x emissions for the 2020 base year, the 2045 Reference Scenario, and the 2045 Proposed Scenario (2045 Alt 3) and Alternatives

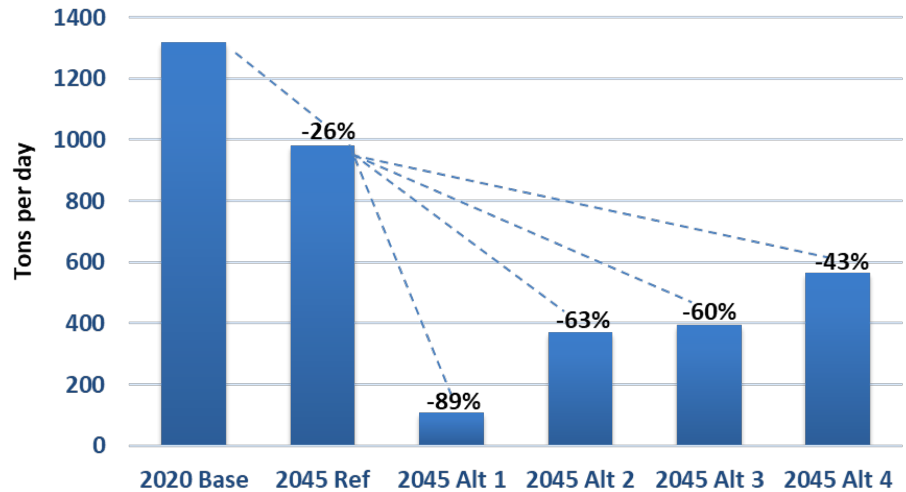
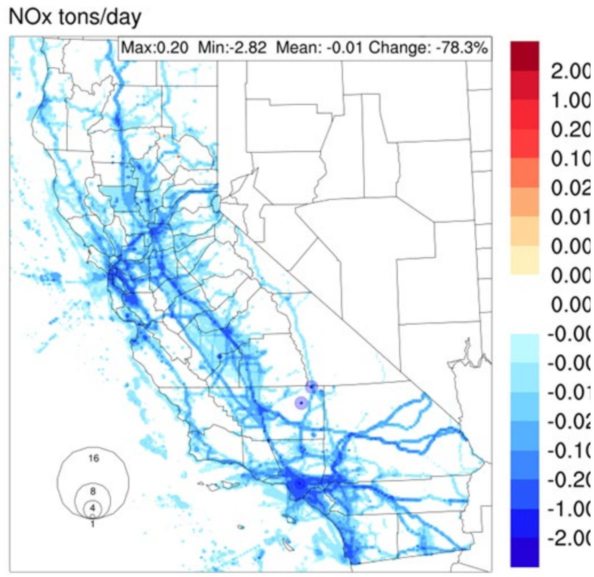


Table H-38. Total reductions in NOx, $PM_{2.5}$, and Reactive Organic Gasses (ROG) in 2045 for each alternative

	Alternative 1 in 2045		Alternative 2 in 2045		Proposed Scenario in 2045		Alternative 4 in 2045	
	January	July	January	July	January	July	January	July
Reductions in NO_x (Tons/day)	873.1	878.1	620.4	619.5	578.9	578.6	406.1	389.3
Reductions in $PM_{2.5}$ (Tons/day)	131.3	129.4	104.1	102.0	94.6	92.1	78.3	66.1
Reductions in ROG* (Tons/day)	286.1	362.8	217.3	282.7	197.1	257.9	144.6	181.9

Figure H-5 displays the spatial distribution of NO_x reductions in Alternative 2 relative to the Reference Scenario, which is representative of the distributions for all four alternatives. Reductions occur throughout the state from on-road and off-road transportation vehicles and equipment, industrial sources including petroleum refineries, residential and commercial buildings, and sources in other AB 32 GHG Inventory sectors. The largest reductions occur in urban areas including the SoCAB due to the large concentration of emission sources in those regions.

Figure H-5. Reductions in NO_x emissions (tons/day) in Alternative 2 relative to the Reference Scenario



Air Quality

The emission reductions within the Proposed Scenario and alternatives subsequently achieve significant improvements in air pollution in California relative to the Reference Scenario, including reductions in concentrations of ground-level ozone and $PM_{2.5}$. To demonstrate this, two different metrics for 24-hour average $PM_{2.5}$ and maximum daily 8-hour average (MD8H) ozone are quantified and shown in Table H-39. First, the peak reductions are reported which represent the single largest reduction predicted for any one point in the modeling domain. This provides an estimate of the maximum impact on air pollution that one location may experience in California. Second, the population-weighted average reductions are reported which provides a more refined estimate of how changes in pollution impact California populations by considering both the spatial distribution of reductions and the spatial distribution of populations to quantify changes in exposure. Within the context of the National Ambient Air Quality Standard (NAAQS) for 24-h $PM_{2.5}$ of 35 ug/m^3, reductions in $PM_{2.5}$ in January are particularly large due to the conditions that result in higher $PM_{2.5}$ levels in the Reference Scenario, ranging in peak from approximately 23 ug/m^3 in Alternative 1 to 12 ug/m^3 in Alternative 4. Peak $PM_{2.5}$ reductions in July are lesser than January, but still notable from a human health standpoint. With similarity to $PM_{2.5}$, reductions in peak MD8H ozone in July are large (i.e., 52 ppb in Alternative 1 to 19 ppb in Alternative 4) when considering the NAAQS is 70 parts per billion (ppb).

Table H-39. Peak and population-weighted reductions in 24-h $PM_{2.5}$ and MD8H ozone for the Proposed Scenario and Alternatives relative to the Reference Scenario

	Alternative 1 in 2045		Alternative 2 in 2045		Proposed Scenario in 2045		Alternative 4 in 2045	
	January	July	January	July	January	July	January	July
Peak Reductions in 24-h $PM_{2.5}$ (μg/m³)	-22.8	-8.4	-17.0	-6.3	-14.9	-5.9	-11.9	-4.3
Population-weighted Reductions in 24-h $PM_{2.5}$ (μg/m3)	-7.9	-2.7	-6.1	-1.9	-5.4	-1.8	-4.4	-1.3
Peak Reductions in MD8H ozone (ppb)	N/A	-51.9	N/A	-33.6	N/A	-27.9	N/A	-19.0
Population-weighted Reductions in MD8H ozone (ppb)	N/A	-17.3	N/A	-8.9	N/A	-8.1	N/A	-4.8

The spatial distribution of reductions in PM2.5 in January and July are provided in Figure H-6 and Figure H-7. In both months the peak improvements occur in the SoCAB due to the conditions which result in the highest baseline PM2.5 concentrations and also the highest emission reductions including the large presence and activity of emission sources, meteorology, topography, and others. Important reductions also occur throughout the San Joaquin Valley, the S.F. Bay area, and the Greater Sacramento area.

Figure H-6. Difference in 24-hour average $PM_{2.5}$ (ug/m^3) in January 2045 in the Proposed Scenario (Alt 3) and Alternatives relative to the Reference Scenario

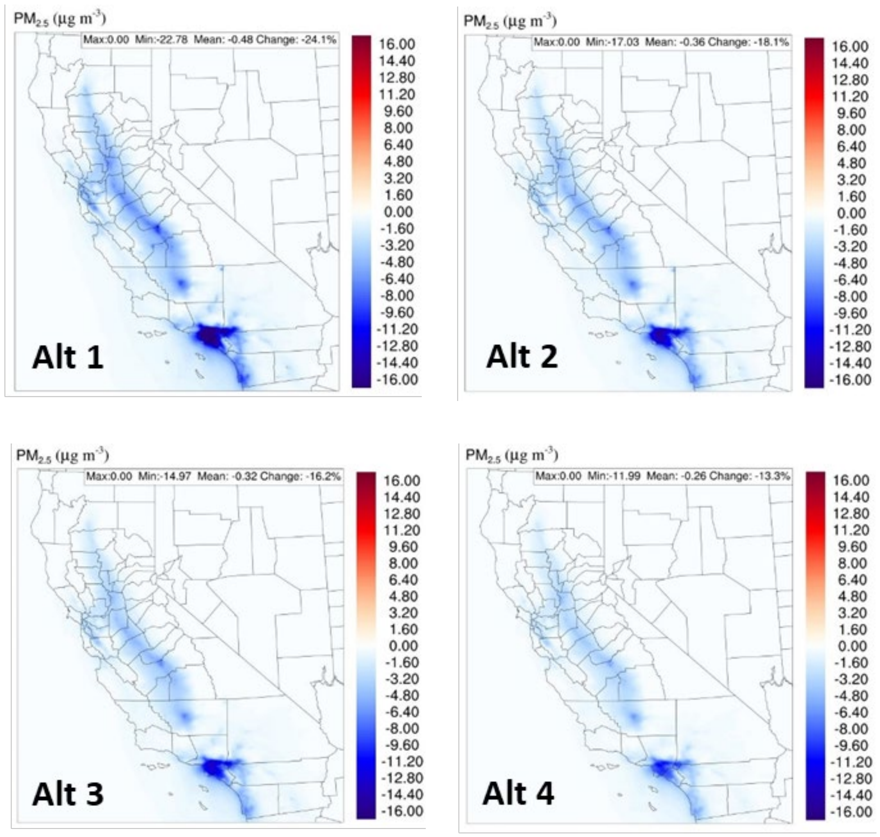
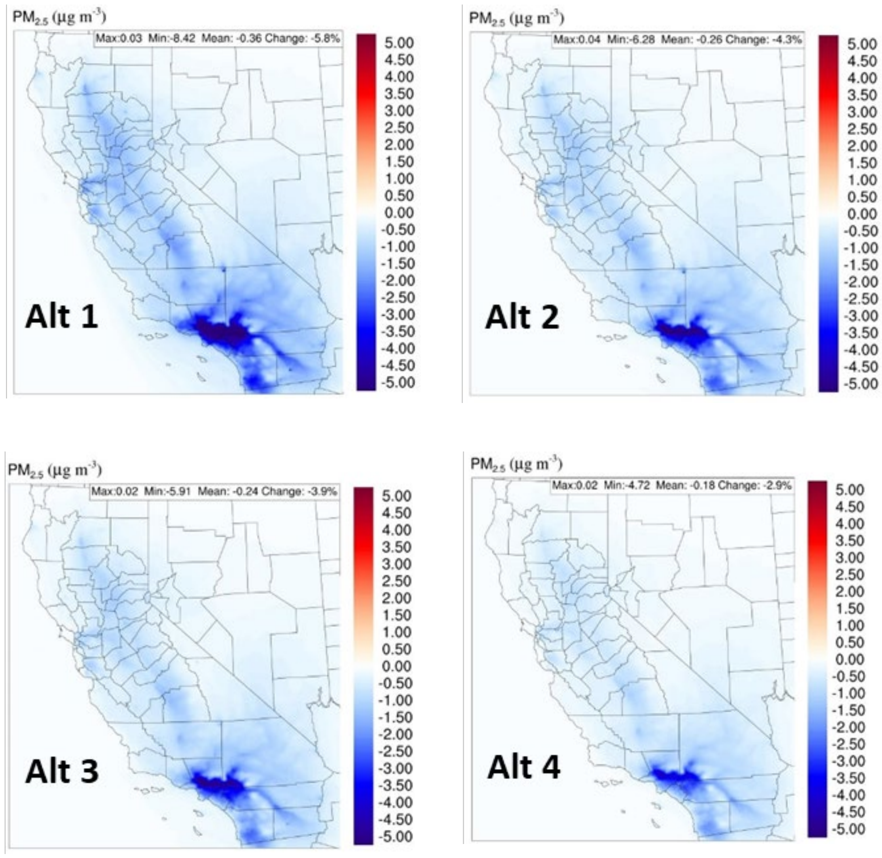
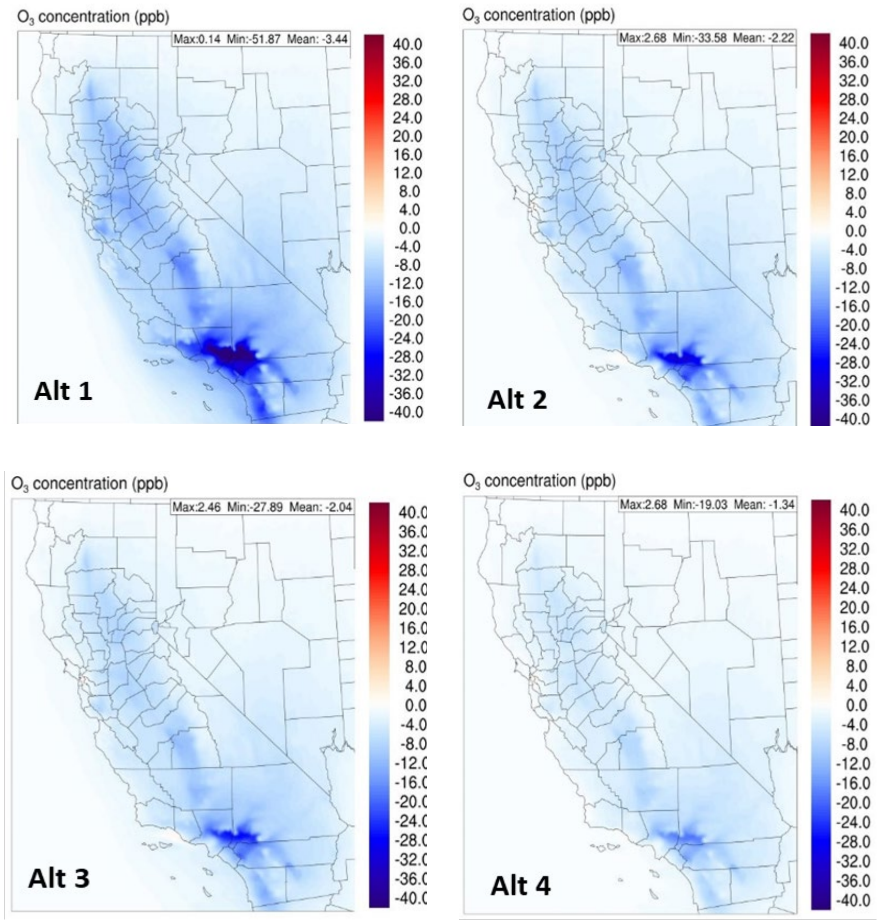


Figure H-7. Difference in 24-hour average $PM_{2.5}$ (ug/m^3) in July 2045 in the Proposed Scenario (Alt 3) and Alternatives relative to the Reference Scenario



Improvements in ground-level ozone for each alternative relative to the Reference Scenario are shown in Figure H-8. With similarity to $PM_{2.5}$, the largest improvements occur in the SoCAB which experiences the highest baseline ozone concentrations.

Figure H-8. Difference in maximum daily 8-hour average ozone (ppb) in July 2045 in the Proposed Scenario (Alt 3) and Alternatives relative to the Reference Scenario



Health Impacts

The avoided incidence of health endpoints associated with reductions in exposure to $PM_{2.5}$ during January 2045 are shown in Table H-40. Avoided incidence of health endpoints from reduced exposure to $PM_{2.5}$ during January 2045Table H-40.

Table H-40. Avoided incidence of health endpoints from reduced exposure to $PM_{2.5}$ during January 2045

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Avoided Mortality, All Cause	$PM_{2.5}$	338	257	236	230
Hospital Admissions, Alzheimers Disease	$PM_{2.5}$	6,983	6,136	5,799	5,179
Hospital Admissions, Parkinsons Disease	$PM_{2.5}$	722	603	559	486
Incidence, Lung Cancer	$PM_{2.5}$	1,334	1,073	981	830
Incidence, Asthma Onset	$PM_{2.5}$	31,027	25,145	22,963	19,557
Acute Myocardial Infarction, Nonfatal	$PM_{2.5}$	176	134	121	97
Asthma Symptoms	$PM_{2.5}$	388,621	299,584	268,079	218,786
Hospital Admissions, Cardiovascular	$PM_{2.5}$	298	226	202	163
Emergency Room Visits, Cardiovascular	$PM_{2.5}$	464	353	316	255
Hospital Admissions, Respiratory	$PM_{2.5}$	47	36	32	25
Emergency Room Visits, Respiratory	$PM_{2.5}$	653	501	447	363

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Work Loss Days	$PM_{2.5}$	139,307	107,225	96,060	78,212

The value of the avoided health incidence from reduced exposure to $PM_{2.5}$ during January 2045 are reported in million 2021 dollars in Table H-41.

Table H-41. Value of avoided health incidence from reduced exposure to $PM_{2.5}$ during January 2045 reported in million 2021 dollars

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Avoided Mortality, All Cause	$PM_{2.5}$	3,289.48	2,499.91	2,304.23	2,236.44
Hospital Admissions, Alzheimers Disease	$PM_{2.5}$	1,234.01	1,084.33	1,024.75	915.13
Hospital Admissions, Parkinsons Disease	$PM_{2.5}$	369.37	308.60	286.19	248.52
Incidence, Lung Cancer	$PM_{2.5}$	151.82	122.10	111.60	94.42
Incidence, Asthma Onset	$PM_{2.5}$	2,891.18	2,343.12	2,139.78	1,822.44
Acute Myocardial Infarction, Nonfatal	$PM_{2.5}$	71.75	54.53	49.47	39.66
Asthma Symptoms	$PM_{2.5}$	0.15	0.12	0.10	0.08

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Hospital Admissions, Cardiovascular	$PM_{2.5}$	5.16	3.92	3.50	2.82
Emergency Room Visits, Cardiovascular	$PM_{2.5}$	0.60	0.46	0.41	0.33
Hospital Admissions, Respiratory	$PM_{2.5}$	0.51	0.39	0.35	0.28
Emergency Room Visits, Respiratory	$PM_{2.5}$	0.64	0.49	0.44	0.36
Work Loss Days	$PM_{2.5}$	25.61	19.72	17.66	14.38

The avoided incidence of health endpoints associated with reductions in exposure to $PM_{2.5}$ and ozone during July 2045 are shown in Table H-42.

Table H-42. Avoided incidence of health endpoints from reduced exposure to $PM_{2.5}$ and ozone during July 2045

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Avoided Mortality, All Cause	$PM_{2.5}$	268	188	177	132
Hospital Admissions, Alzheimers Disease	$PM_{2.5}$	3,597	2,706	2,584	2,046

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Hospital Admissions, Parkinsons Disease	$PM_{2.5}$	325	238	226	176
Incidence, Lung Cancer	$PM_{2.5}$	536	386	364	280
Incidence, Asthma Onset	$PM_{2.5}$	12,773	9,349	8,778	6,784
Acute Myocardial Infarction, Nonfatal	$PM_{2.5}$	62	43	41	31
Asthma Symptoms	$PM_{2.5}$	138,729	99,356	92,699	69,869
Hospital Admissions, Cardiovascular	$PM_{2.5}$	101	71	66	50
Emergency Room Visits, Cardiovascular	$PM_{2.5}$	159	112	105	79
Hospital Admissions, Respiratory	$PM_{2.5}$	16	11	10	8
Emergency Room Visits, Respiratory	$PM_{2.5}$	229	163	153	115
Work Loss Days	$PM_{2.5}$	49,428	35,188	32,911	24,738
Avoided Mortality, Respiratory	Ozone	360	171	155	87

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Incidence, Asthma Onset	Ozone	2,865	1,526	1,364	821
Emergency Room Visits, Respiratory	Ozone	1,937	1018	909	542
Asthma Symptoms	Ozone	1,201,704	654,334	587,897	356,922
Hospital Admissions, Respiratory	Ozone	169	79	71	40

The value of the avoided health incidence from reduced exposure to $PM_{2.5}$ and ozone during July 2045 are reported in million 2021 dollars in Table H-43.

Table H-43. Value of avoided health incidence from reduced exposure to $PM_{2.5}$ and ozone during July 2045 reported in million 2021 dollars

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Avoided Mortality, All Cause	$PM_{2.5}$	2,615.79	1,831.68	1,721.76	1,285.72
Hospital Admissions, Alzheimers Disease	$PM_{2.5}$	634.53	477.45	455.84	360.95
Hospital Admissions, Parkinsons Disease	$PM_{2.5}$	167.66	122.75	116.48	90.56
Incidence, Lung Cancer	$PM_{2.5}$	60.64	43.63	41.22	31.70

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Incidence, Asthma Onset	$PM_{2.5}$	396.01	289.85	272.16	210.34
Acute Myocardial Infarction, Nonfatal	$PM_{2.5}$	25.13	17.66	16.58	12.45
Asthma Symptoms	$PM_{2.5}$	0.05	0.04	0.04	0.03
Hospital Admissions, Cardiovascular	$PM_{2.5}$	1.74	1.22	1.15	0.86
Emergency Room Visits, Cardiovascular	$PM_{2.5}$	0.21	0.15	0.14	0.10
Hospital Admissions, Respiratory	$PM_{2.5}$	0.17	0.12	0.11	0.08
Emergency Room Visits, Respiratory	$PM_{2.5}$	0.22	0.16	0.15	0.11
Work Loss Days	$PM_{2.5}$	9.09	6.47	6.05	4.55
Avoided Mortality, Respiratory	Ozone	3,503.99	1,662.80	1,506.42	846.75
Incidence, Asthma Onset	Ozone	88.70	47.24	42.22	25.43
Emergency Room Visits, Respiratory	Ozone	1.90	1.00	0.89	0.53

Endpoint	Pollutant	Alternative 1	Alternative 2	Proposed Scenario	Alternative 4
Asthma Symptoms	Ozone	434.06	236.35	212.35	128.92
Hospital Admissions, Respiratory	Ozone	8.51	3.97	3.60	2.00
Total		***7,948.4***	***4,742.5***	***4,397.1***	***3,001.1***

Table H-44. Value of the health benefits occurring within California census tracts identified as DAC using CalEnviroScreen 4.0

	Season	Valuation in million $2021			
		California	South Coast	San Joaquin Valley	San Francisco Bay
Alternative 1	**July**	2166.1	1829.0	179.6	44.0
	January	2497.8	1941.1	363.0	63.1
Alternative 2	**July**	1310.0	1083.0	133.9	23.2
	January	2028.7	1571.2	306.0	47.8
Proposed Scenario	**July**	1201.6	995.7	119.7	22.0
	January	1846.8	1432.5	276.9	43.1
Alternative 4	**July**	827.2	684.1	85.5	13.6
	January	1686.0	1302.6	250.6	40.8

Economic Analysis

This section provides additional detail on the methods used in the macroeconomic analysis of the Draft 2022 Scoping Plan. Rhodium Group (Rhodium) analyzed the economic impact of achieving carbon neutrality on the California economy in 2035 and 2045. To conduct the analysis, Rhodium relied on cost data from E3's PATHWAYS model as an input to the macroeconomic model, IMPLAN. PATHWAYS cost data estimate changes in expenditures, by sector, for each alternative relative to the Reference Scenario. The incremental changes in spending are then input into IMPLAN to estimate the overall impact of achieving carbon neutrality on the California economy.

Modeling Framework

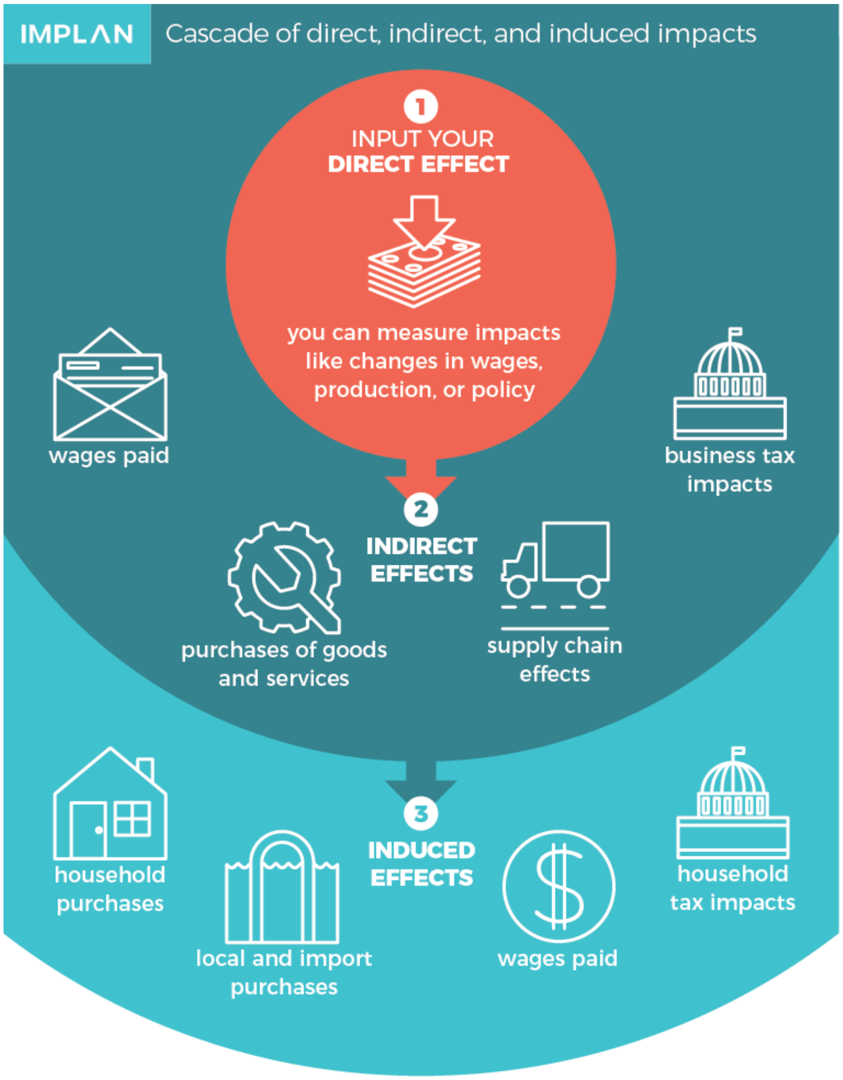
IMPLAN

IMPLAN[121] is an input-output model that estimates the impact of economic changes based on the interdependencies of 546 sectors across the economy. IMPLAN relies on data from the US Bureau of Economic Analysis (BEA), US Department of Agriculture (USDA), the US Bureau of Labor Statistics (BLS), and the US Census Bureau to construct production functions, industry and commodity output, employment and wage data, industry value added, and personal consumption expenditures. In addition, IMPLAN's regulation Social Accounting Matrix (SAM) captures regional non-market financial transfers between industries and transfers between government and individuals using trade flow data allowing analysis of the indirect and induced effects of economic activity across linked regions.

Rhodium used IMPLAN to model how the direct costs from PATHWAYS flow across sectors in the California economy. A change in spending in one sector impacts related sectors as well as employment and household spending, resulting in direct, indirect, and induced impacts as outlined in Figure H-9.

[121] See *https://implan.com/*

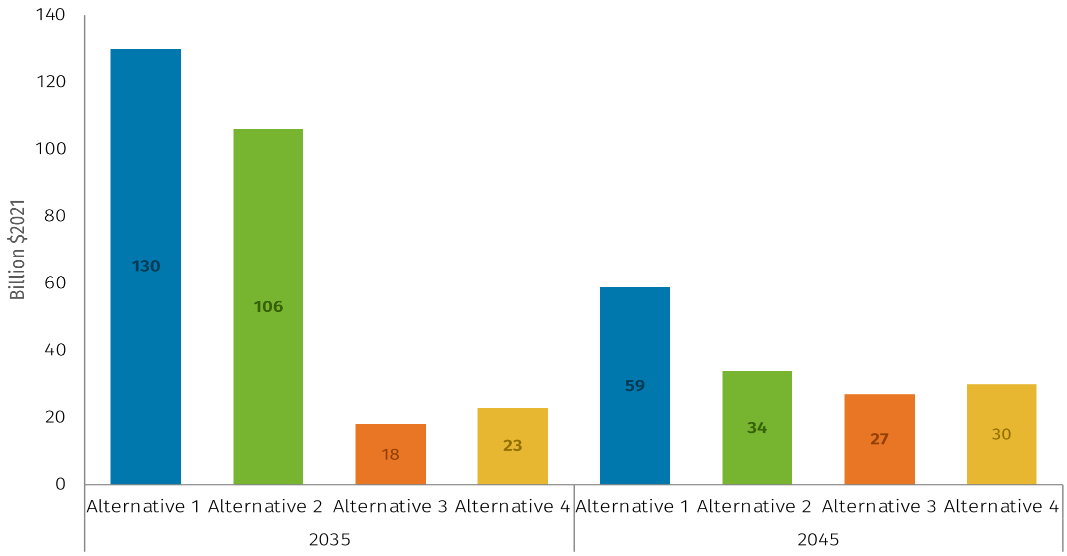
Figure H-9. IMPLAN economic impact flow



Direct Costs

Figure H-10 shows the direct costs from PATHWAYS for each alternative relative to the Reference Scenario. The assumptions and references for the costs were summarized in the Enegy and Emissions Modeling section of the appendix. These direct costs are inputs to IMPLAN across the various economic sectors and households.

Figure H-10. Direct costs from PATHWAYS in a single year relative to the Reference Scenario for the Proposed Scenario (Alternative 3) and Alternatives in 2035 and 2045



There are four categories of direct costs in PATHWAYS:

- Cost of Carbon Dioxide Removal (CDR) in California
- Cost of purchasing capital stock
- Cost and saving from changing fuel expenditures
- Demand change measure cost or the cost of energy efficiency measures across sectors

Each of these direct cost categories is translated into IMPLAN to ensure that costs are distributed across economic sectors and households to best approximate the economic impact of achieving carbon neutrality on California. CDR costs are modeled as an increase in expenditures in solar electricity generation. This modeling choice is based on CDR technology and cost assumptions in the PATHWAYS modeling conducted by E3. The modeling assumes that CDR is physically located in California and that the cost of CDR is passed through to consumers. Thus, the price of goods and services will increase to account for the higher costs due to CDR. The cost of CDR is split across IMPLAN's 9 household income categories.[122] Thus, each income group faces the same higher costs.

The cost of purchasing new capital stock is modeled as a change in expenditures across IMPLAN's 546 economic sectors. For example, in IMPLAN, increased sales of heat pumps result in an increase in expenditures in the heating manufacturing sector, while changes in spending on ventilation systems will directly impact the air purification

[122]See *https://support.implan.com/hc/en-us/articles/360052212413-Household-Income-Events*

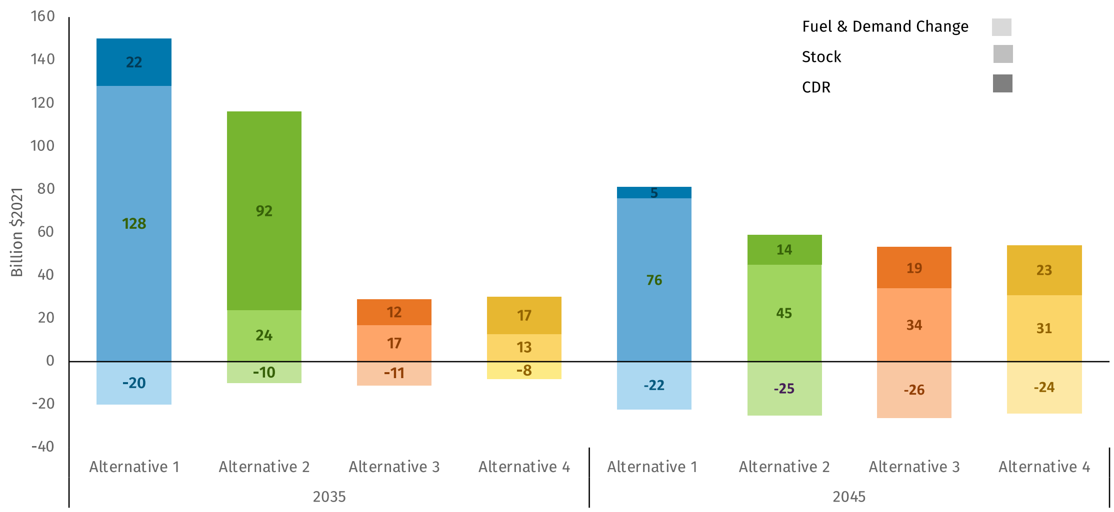
and ventilation sector. As modeled in PATHWAYS, Alternative 1 has high stock costs due to the accelerated retirement of vehicles and equipment. The stock cost in Alternative 1 includes the residual value in equipment that is retired before the end of life. The costs of stock purchases, both at the residential and commercial level, are passed to consumers through an increase in prices. Stock costs are assigned to households in IMPLAN evenly across income categories.

Changes in energy use are modeled as a change in expenditure in the specific energy sector. For example, changes in spending on diesel and gasoline are modeled as changes in the petroleum refining industry, while changes in spending on electricity are reflected in electric power generation sectors – fossil fuel, nuclear, solar, wind, geothermal, and biomass. As modeled in PATHWAYS, changes in energy spending reflect net savings across the alternatives and any costs associated with the changing energy mix are not passed through to households.

According to PATHWAYS, demand measure change costs are costs associated with energy efficiency improvements across sectors. These costs are modeled in IMPLAN as an increase expenditures in impacted sectors and are passed through to households as an increase in the price of goods. For example, if food processing facilities in California purchase new heat boilers, the cost of the capital equipment will be passed through to consumers as a higher purchase price for food products. The cost of demand measure changes are assigned evenly across household income categories.

Figure H-11 presents the direct cost of each Scoping Plan Alternative by cost category as modeled in PATHWAYS by E3. Given the small cost of demand change measures, they are rolled into the change in fuel expenditures. Direct costs vary substantially across alternatives and across categories. E3 found that there are net fuel savings across all alternatives, which reflects the changing fuel mix in the Scoping Plan Alternatives relative to the Reference Scenario. CDR costs vary substantially across alternatives, from $5 billion to $92 billion dollars.

Figure H-11. Cost and savings from PATHWAYS in a single year relative to the Reference Scenario for the Proposed Scenario (Alternative 3) and Alternatives in 2035 and 2045



Results

The modeling produced the estimated economic impact of achieving carbon neutrality across the four alternatives in 2035 and 2045. These results are annual, and do not represent the cumulative costs of each scenario. As there are direct costs to each alternative, as outlined in Figures H-10 and H-11, achieving carbon neutrality slows the growth of the California economy. While direct costs are presented as a positive value relative to a baseline of zero costs in Figures H-10 and H-11, macroeconomic impacts are shown as a negative impact relative to the baseline of a growing California economy.

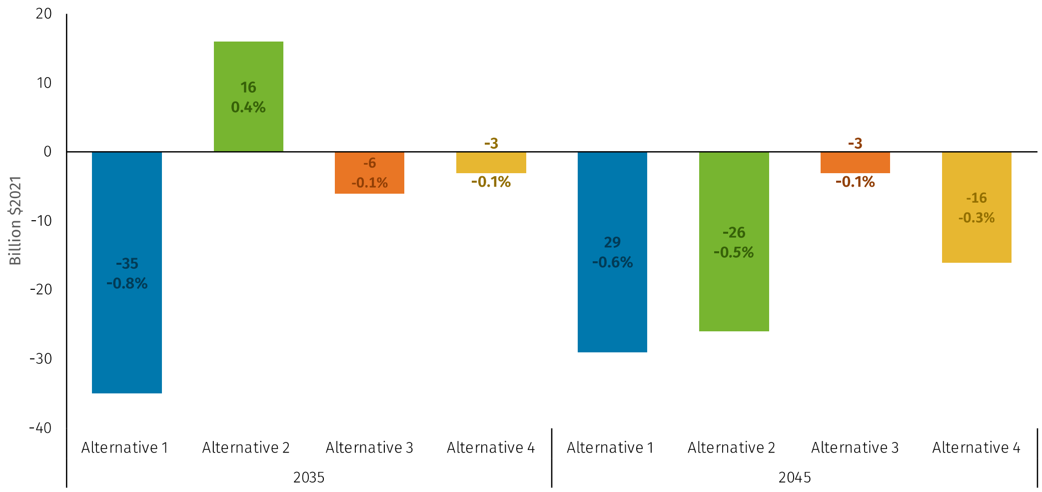
Gross State Product

Figure H-12 presents the impact on the overall California economy or Gross State Product (GSP) of achieving carbon neutrality. The California economy is anticipated to grow from $3.2 trillion in 2021 to $4.2 trillion in 2035 and $5.1 trillion in 2045.[123] The percentages shown in the figure represent the change in GSP relative to the anticipated size of the California economy in 2035 and 2045. All alternatives will slow the growth of the California economy by varying amounts. Alternative 1 has the largest impact on the economy in both 2035 and 2045, representing an impact of slowing the economy by 0.8% in 2035 and -0.6% in 2045. In 2035, Alternative 2 shows a slightly positive impact on the California economy due to its reliance on CDR to achieve carbon neutrality. CDR comprises 86% of the direct costs of Alternative 2 and, as modeled, increases

[123] CARB projection based on California Department of Finance forecasts.

expenditures on solar electricity generation and results in costs to households, which reduces spending in service industries. The overall impact of CDR is a slightly positive impact on the California economy, given the ripple effects of changes in expenditures in these sectors. The Proposed Scenario has the smallest impact on the California economy in 2045, reducing the size of the economy by 0.1% relative to the projected GSP in 2045.

Figure H-12. Gross State Product impact from IMPLAN in a single year relative to a growing California economy for the Proposed Scenario (Alternative 3) and Alternatives in 2035 and 2045



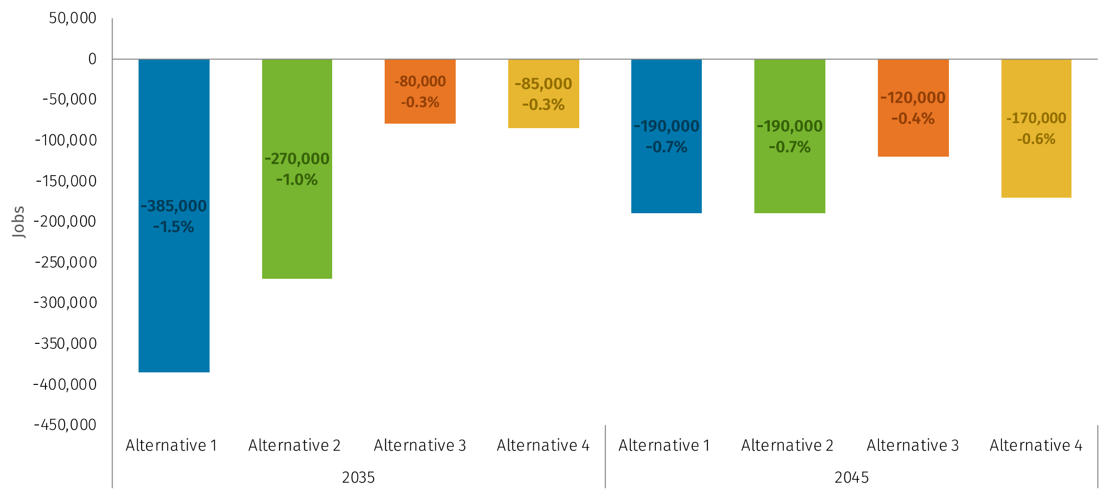
The variation across alternatives is due to the difference in direct costs across categories. Some industrial sectors have a larger impact on the economy. For instance, spending on construction impacts construction, engineering, spending on raw materials, and manufacturing of equipment. To the extent those impacts are within California they can have a large impact on the overall economy. Spending in service sectors, like restaurants and personal care services, may impact fewer sectors limiting the overall impact of changes.

Employment

Figure H-13 presents the impact of achieving carbon neutrality on employment in 2035 and 2045. Employment is an industry-specific annual average that includes full-time, part-time, and seasonal employment. IMPLAN employment uses the same definition as the BLS and BEA. In California, employment is anticipated to grow to 23.5 million jobs in 2021 to 26.3 million in 2035 and to 27.7 million in 2045.[124] The percentages in Figure H-13, therefore, correspond to the impact on employment relative to growing California employment levels in 2035 and 2045.

[124] CARB projection based on California Department of Finance forecasts.

Figure H-13. Employment impact from IMPLAN in a single year relative to the growing California workforce for the Proposed Scenario (Alternative 3) and Alternatives in 2035 and 2045



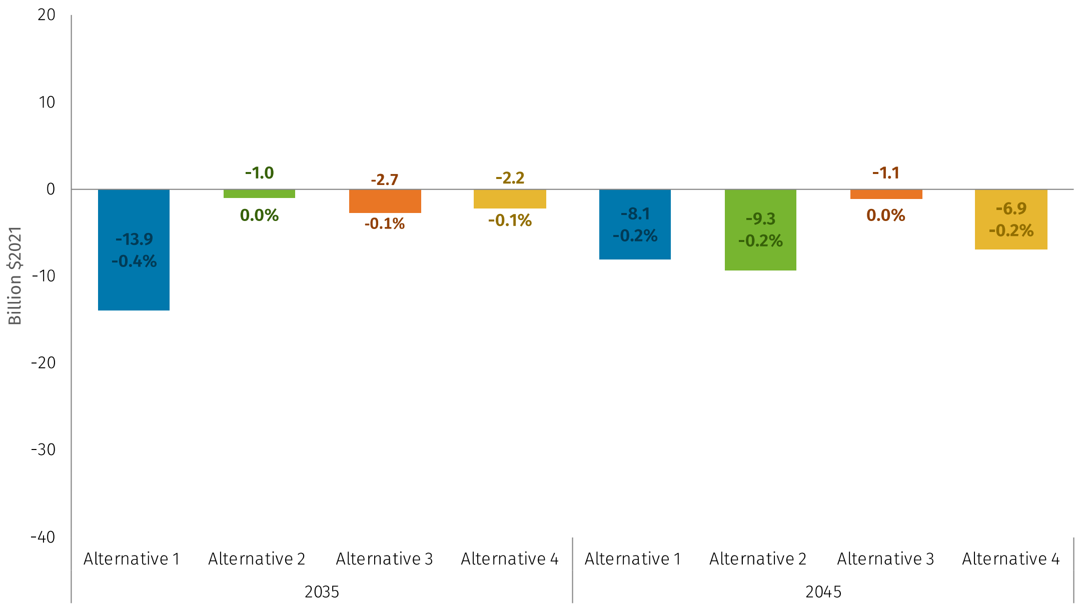
All alternatives slightly slow the growth of employment relative to the Reference Scenario. Alternative 1 has the largest impact in 2035 and 2045 resulting in a 1.5% reduction in employment in 2035 relative and 0.7% reduction in 2045, relative to projected employment in those years. The Proposed Scenario has the smallest impact on California employment in 2035 and 2045, reducing employment by 0.3% in 2035 and 0.4% in 2045. While the overall impact of achieving carbon neutrality is modest relative to the growing California workforce, there is large variation across alternatives. In 2035, Alternative 1 has 5 times the impact on employment relative to Alternative 3. In 2045, the impact of Alternative 1 is 1.5 times the impact of Alternative 3.

Personal Income

Figure H-14 presents the impact of achieving carbon neutrality on personal income. This is a measure of employee wages and benefits and represents the total value of employment income paid during a year. Personal income in California is projected to rise from \$2.7 trillion in 2021 to \$3.6 trillion in 2035 and \$4.4 trillion in 2045.[125] The percentages in Figure H-14 are relative to growing California personal income in 2035 and 2045.

[125] CARB projection based on California Department of Finance forecasts.

Figure H-14. Impact from IMPLAN in a single year relative to growing personal income for the Proposed Scenario (Alternative 3) and Alternatives in 2035 and 2045



The impact on personal income is modest across all alternatives, ranging from -0.4% impact in 2035 under Alternative 1 to essentially no impact in Alternative 2 in 2035 and the Proposed Scenario in 2045. The difference across alternatives, however, is large. The impact of Alternative 1 in 2035 is nearly 13 times that of the Proposed Scenario in 2045, the year the alternatives achieve carbon neutrality.

Household Impacts

California Department of Finance population forecasts[126] was used to estimate the number of California households in 2035 and 2045. Assuming households grow in line with population, households will increase an average of 0.3% each year rising from 13.3 million in 2020 to 14.6 million in 2035 and 15.0 million in 2045.

From the direct costs modeled in PATHWAYS (as outlined in Figure H-10), households will see increased costs from the purchase of new capital stock and saving from reduced spending on fuel. Households will also face increased costs associated with CDR, demand measure change costs and commercial stock purchases that are assumed to be passed directed to consumers. The impact to California households, however, is not limited to the costs outlined in PATHWAYS as changes in relative prices, employment, and wages can impact household well-being. Personal income, which captures the direct, indirect, and induced impacts, is a metric commonly used to evaluate the impact of policies on households.

[126] https://dof.ca.gov/forecasting/demographics/projections/

Figure H-15 presents the change in personal income by household of achieving carbon neutrality. The change in personal income varies greatly across alternatives. Alternative 1 has the highest cost to household income in 2035 and Alternative 2 has the highest cost in 2045. The variation in personal income is due to varying expenditures across sectors in the alternatives. Achieving carbon neutrality in 2035 under Alternative 1 will cost California households an average of $80 a month in income in 2035. Achieving carbon neutrality in 2045 under Alternative 3 will cost California households an average of $6 a month in income 2045.

Figure H-15. Impact from IMPLAN in a single year relative to growing California households and personal income for the Proposed Scenario (Alternative 3) and Alternatives in 2035 and 2045