Bay Area Air Quality Management District

Electric Infrastructure Impacts from Proposed Zero NOx Standards

November 3, 2022

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Acronyms

Acronym	Definition
AC	Air Conditioning
ACC	(CPUC) Avoided Cost Calculator
ACS	American Community Survey
ATB	(NREL) Annual Technology Baseline
BAAQMD	Bay Area Air Quality Management District
BAU	Business as Usual
CA	California
CARB	California Air Resources Board
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CPUC	California Public Utilities Commission
GHG	Greenhouse Gas
HP	Heat Pump
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning
IRP	(CPUC) Integrated Resource Planning
LCOE	Levelized Cost Of Electricity
NREL	National Renewable Energy Laboratory
NOx	Nitrogen Oxides
PCAF	Peak Capacity Allocation Factor
PG&E	Pacific Gas & Electric
PV	Photovoltaic

1. Executive Summary

The Bay Area Air Quality Management District (BAAQMD) is evaluating proposed zero NOx standards for residential and commercial space and water heating devices. Today, the only technologies that meet zero NOx standards for these end uses are electric devices, although gas-fired technologies that meet zero NOx standards could be developed in the future. For the purposes of this study, E3 has assumed that electric heat pump devices are used to comply with the proposed standards. E3 has analyzed the potential electric load increases from space heating, water heating, and air conditioning as well as the associated electric grid impacts. This analysis will be used to support an assessment of the potential conservative (upper end) impacts of the proposed standards on electric infrastructure under the California Environmental Quality Act (CEQA). If gas-fired technologies are developed that meet the proposed zero NOx standards and these devices are adopted by some customers, the overall impacts on electric infrastructure would be smaller than estimated here.

All potential electric grid impacts were evaluated relative to two reference scenarios: a Low Policy Reference, which assumes no major state policy changes in support of building electrification, and a High Policy Reference, which assumes major state policy support for building electrification by the 2030s.

There are two broad results from this study:

+ The potential electric grid impacts of the proposed zero NOx standards are highly dependent on what other policies California enacts around building electrification to meet the state's climate goals.
    + Relative to the Low Policy Reference, the zero NOx standards would result in incremental load impacts, capacity impacts, and infrastructure needs by 2050.
    + Relative to the High Policy Reference, the zero NOx standards would result in load, capacity, and infrastructure impacts occurring earlier than would otherwise be expected, but there would be very small net impacts by 2050.
+ The largest potential impacts of the proposed standards would be from increased electric loads and the associated need for additional zero-carbon generation, assumed in this study to be utility-scale solar, to meet these electric loads.
    + There would also be some incremental peak loads, leading to additional impacts for generation capacity, transmission capacity, and distribution capacity.

Table 1 summarizes the potential electric grid impacts that were determined in this study. While the distribution capacity impacts described in the table would occur within the BAAQMD's geographic region, the transmission capacity impacts may occur outside the Bay Area and the utility-scale solar and battery storage impacts would be spread across California and the Western United States.

Table 1: Summary of potential 2050 electric grid impacts of proposed zero NOx standards

	Impact relative to Low Policy Reference	**Impact relative to High Policy Reference**
Utility-scale solar *to serve electric loads*	2,180 MW new solar by 2050	70 MW new solar by 2050 *+ accelerated build in 2030s & 2040s*
4-hour battery storage *for generation capacity*	680 MW new batteries by 2050	< 10 MW new batteries by 2050 *+ accelerated build in 2030s & 2040s*
Transmission Capacity	460 MW impact by 2050	< 10 MW impact by 2050 *+ accelerated build in 2030s & 2040s*
Distribution Capacity	420 MW impact by 2050	< 10 MW impact by 2050 *+ accelerated build in 2030s & 2040s*

2. Background

The BAAQMD is evaluating amendments to rules 9-4 and 9-6, which govern nitrogen oxide (NOx) emissions from residential and commercial space and water heating systems. The proposed amendments would introduce zero NOx standards for devices covered under these rules. Today, the only technologies that meet zero NOx standards for these end uses are electric space and water heating devices. In the future, gas-fired technologies that meet the proposed standards could be developed. In this study, to determine potential conservative (upper end) impacts on electric infrastructure, it is assumed that gas space heating and water heating devices would be replaced by electric heat pump devices upon burnout.

The following rule changes were proposed:

- Rule 9-4 governs emissions from gas-fired furnaces.
    - BAAQMD proposes zero NOx standards for all residential and commercial gas-fired furnaces, applicable on January 1, 2029.
- Rule 9-6 governs emissions from gas-fired water heaters and boilers with heat input capacity less than 2,000,000 Btu/hr.
    - BAAQMD proposes zero NOx standards for water heaters and boilers with heat input capacity less than 75,000 Btu/hr, applicable on January 1, 2027.
    - BAAQMD proposes zero NOx standards for water heaters and boilers with heat input capacity between 75,000 Btu/hr and 2,000,000 Btu/hr, applicable on January 1, 2031.

In this study, E3 has analyzed the electric grid impacts of the proposed standards, assuming that covered gas devices would be replaced by electric heat pumps at device retirement. A widespread shift to electric heat pumps would result in electric load growth, requiring new infrastructure to support these loads.

Electric grid impacts have been considered in four categories:

- **Electric load**: generation resources to serve new electric loads, not necessarily during peak hours
- **Generation capacity**: resources to serve new electricity needs at times of peak demand
- **Transmission capacity**: new electric transmission infrastructure to deliver electricity from generators to the distribution system, associated with new peak loads
- **Distribution capacity**: new electric distribution infrastructure to deliver electricity from the transmission system to retail customers, associated with new peak loads

3. Heat Pump Adoption Scenarios

Technology Assumptions

This modeling assumed a baseline gas technology for each end use: residential space heating, residential water heating, commercial space heating, and commercial water heating. The modeling also includes assumptions regarding the heat pumps that would replace gas devices under the proposed zero NOx standards. Details on the technology assumptions are provided in the section **Appendix: Detailed Methodology**.

Zero NOx Standard Dates and Coverage

Table 2 illustrates key modeling assumptions regarding the proposed zero NOx standards. The implementation dates for the proposed standards are based on the proposed rule amendments, as described above in the section **Background**. Coverage reflects the share of natural gas usage assumed to be covered by the amendments. This analysis assumes that 50% of commercial water heating would be served by large water heaters with capacity greater than 2 MMBtu/hr and thus would not be covered under these standards.

Table 2: Zero NOx standard implementation dates and assumed coverage

End use	Zero NOx standard implementation date	Coverage (%)
Residential Space Heating	Jan 1, 2029	100%
Residential Water Heating	Jan 1, 2027	100%
Commercial Space Heating	Jan 1, 2029	100%
Commercial Water Heating	Jan 1, 2031	50%

Sensitivities were also performed considering implementing the standards in 2026 or in 2035. Results of these sensitivities are included in the section **Appendix: Sensitivities on Implementation Year**.

Reference Scenarios and Proposed Standards Scenario

The impact of the proposed zero NOx standard should be evaluated relative to a reference scenario in which the proposed standards were not implemented. Absent the zero NOx standards, some level of heat pump adoption would nevertheless occur, driven by economics, customer preferences, and/or other policy changes. E3 measured the impact of the proposed zero NOx standards as the *incremental* impact on electric load, infrastructure development, and land use above what would otherwise have occurred.

Reference Scenarios

Due to uncertainty regarding future state policies to support building electrification, there is a wide range of plausible heat pump adoption levels absent the proposed zero NOx standards. To reflect this uncertainty, this study considered two reference scenarios of heat pump adoption for space and water heating. Both scenarios come from the California Air Resource Board (CARB) 2022 Draft Scoping Plan Update.[1]

- The **Low Policy Reference** assumes heat pump adoption consistent with the 2022 Draft Scoping Plan BAU Reference Scenario. This case represents a business-as-usual (BAU) future in which California does not meet its 2030 or 2045 greenhouse gas (GHG) emissions targets. Regarding heat pumps, this case reflects existing and planned levels of incentives for heat pumps and no major policy changes supporting building electrification, resulting in relatively low heat pump adoption through 2045.
- The **High Policy Reference** assumes heat pump adoption consistent with the 2022 Draft Scoping Plan Proposed Scenario.[2] This case reflects major policy changes to decarbonize all sectors of California's economy aligned with achieving the state's GHG emissions targets. State-level policies drive a fast pace of heat pump adoption in the High Policy Reference.

While the Low Policy Reference sees significant levels of gas devices sold through 2045, the High Policy Reference reflects the goal that "all new appliances sold in California would be zero-emission by 2035 for installation in residential buildings and by 2045 for installation in commercial buildings." More details on these sales targets, including policy considerations, are provided in the Scoping Plan Appendix on Building Decarbonization.[3]

Proposed Zero NOx Standards Scenario

Heat pump adoption under the proposed standards was assumed to follow the Low Policy Reference until the implementation year for the relevant zero NOx standard, after which it would grow following a simplified linear adoption trajectory over the number of years of the corresponding gas device lifetime. As an example, residential gas furnaces were modeled to have a 16-year lifetime and a proposed zero NOx standard taking effect on January 1, 2029. Thus, residential heat pump adoption for space heating in the Proposed Standards scenario follows a linear trajectory from 5.9% in 2028 (the level of the Low Policy Reference) to 100% by 2044 (16 years later).

Residential Heat Pump Space Heating Sales and Adoption

Figure 1 illustrates the annual *sales share* and *stock share* of heat pumps for residential space heating over time. The sales share indicates how many heat pumps are sold every year as a share of all residential space

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[1] https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

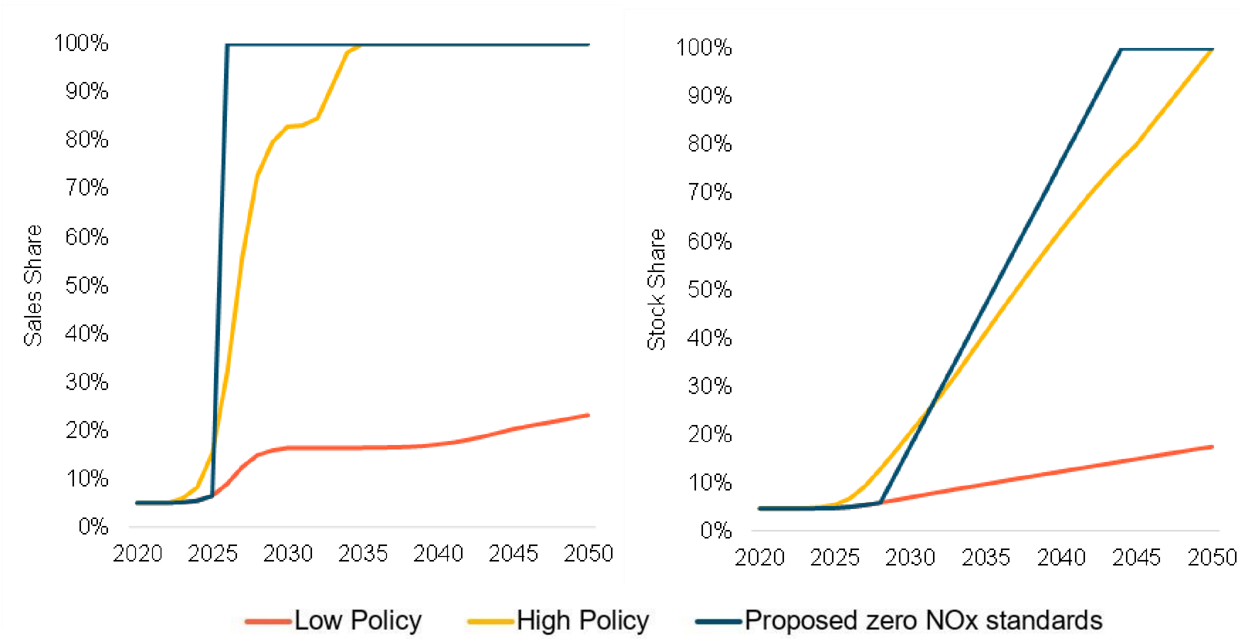
[2] The Proposed Scenario was formerly known as "Alternative 3." Policy measures are outlined here: https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-appendix-c-ab-197-measure-analysis.pdf

[3] https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-appendix-f-building-decarbonization.pdf

heating devices sold. The stock share indicates the annual level of adoption of heat pumps among residential space heating devices installed in buildings, measured at the end of the year.

Assuming that heat pumps are installed to comply with the zero NOx standards, there would be a direct impact on the sales share of heat pumps once the proposed standards are implemented. However, it is the stock share that determines electric system impacts, as it describes the physical adoption levels of heat pumps in buildings. The stock share of heat pumps lags the sales share, as building devices have a relatively long lifetime and are assumed to be replaced at the end of this lifetime. This means that, after the implementation of zero NOx standards, it would take years for heat pumps to reach high adoption levels and cause corresponding electric system impacts.

Figure 1: Potential residential heat pump space heating sales share (left) and stock share (right)



In the Low Policy Reference, heat pump sales reach 16% of sales of residential spaces heating devices by 2030 and grow to 23% of sales by 2050. Adoption levels reach 7% of residential space heating devices by 2030, increasing to 18% by 2050. In the High Policy Reference, heat pumps sales make up 83% of residential space heating devices sold in 2030, increasing to 100% of sales by 2050. This rapid sales trajectory results in heat pump adoption levels growing to 20% of residential space heating devices by 2030 and achieving 100% saturation by 2050. Under the proposed zero NOx standards and assuming that heat pumps are used to comply with the proposed standards, heat pump sales follow the Low Policy scenario and then shift to 100% of space heating devices sold in 2029 and after. Heat pump adoption then increases linearly over the next 16 years, reaching 100% by the end of 2044.

The linear adoption trajectory used here is a simplification and neglects that device lifetime distributions are generally "long-tailed," meaning that a small percentage of gas devices will last significantly longer than the average lifetime. Thus, our analysis using a linear adoption trajectory can be seen as a conservative (upper end) estimate of potential grid impacts associated with heat pump adoption by 2050.

More details on the reference scenarios, as well as sales shares and stock shares for residential water heating, commercial space heating, and commercial water heating, are provided in the section **Appendix: Detailed Methodology**.

4. Electric Load Impacts and Solar Energy Needs

Load Impact Methodology

Space Heating and Water Heating Loads

Maximum potential space heating and water heating load impacts are calculated based on gas usage data provided to BAAQMD by Pacific Gas and Electric (PG&E). These data include annual gas usage in BAAQMD's territory for four end uses: residential space heating, residential water heating, commercial space heating, and commercial water heating. For each end use, the maximum potential load impact assumes that 100% of gas demand for that end use shifts to heat pumps and is adjusted for the device performance characteristics of gas devices and heat pumps, as described in the section **Appendix: Detailed Methodology**. Annual load impacts are then calculated for each end use as a percentage of the maximum potential load impact, based on the incremental heat pump adoption relative to a reference scenario in that year.

As the maximum potential load impacts are based on existing data on gas usage, the modeling only reflects existing buildings. Excluding the impact of the proposed zero NOx standards on new buildings is a simplification that reflects the trend toward all-electric reach codes in many Bay Area municipalities and the potential for an all-electric building code in the next CEC code cycle, as the proposed zero NOx standards would not have any impact on buildings that are already all-electric.

Air Conditioning Loads

Air conditioning (AC) is a major source of electric load and a key driver of system peaks in warm climates. Heat pump HVAC units provide both space heating and space cooling in a single device. Some homes in the Bay Area do not currently have AC. Since customers who install a heat pump are assumed to make use of the cooling function, heat pump adoption is modeled to result in new air conditioning load for these households.

Conversely, heat pumps installed in residential buildings that currently have air conditioning may decrease cooling loads for the building, as new heat pump technologies generally perform better than existing air conditioners. More details are provided in the section **Appendix: Detailed Methodology**.

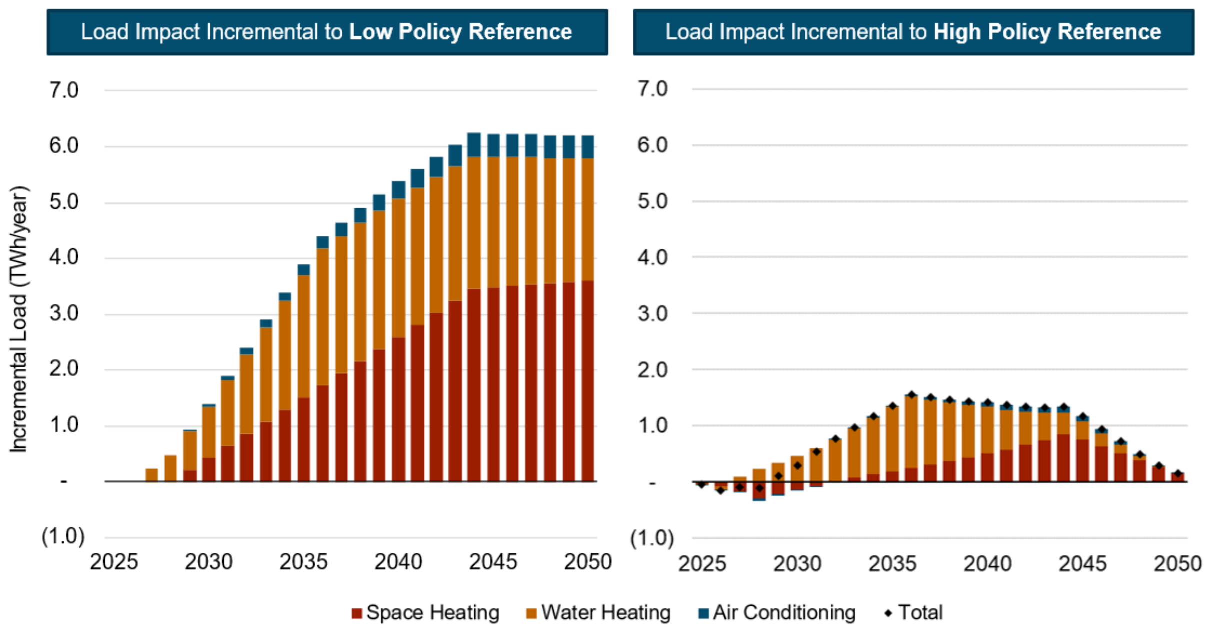
Current levels of AC adoption and estimates of future adoption are based on data from the CEC's 2019 Residential Appliance Saturation Survey (RASS).[4] Average per-building air conditioning loads were calculated from the National Renewable Energy Laboratory (NREL) ResStock and ComStock databases[5]. More details are provided in the section **Appendix: Detailed Methodology**.

[4] https://www.energy.ca.gov/sites/default/files/2021-08/CEC-200-2021-005-ES.pdf
[5] https://resstock.nrel.gov/, https://comstock.nrel.gov/

Electric Load Impacts

Figure 2 depicts the potential annual load impact of the proposed zero NOx standards by end use, relative to each reference scenario. This analysis considers loads from residential and commercial space heating, water heating, and air conditioning for buildings within BAAQMD's boundaries. The figure shows incremental loads for these end uses, *i.e.*, the difference between potential loads under the proposed zero NOx standards versus loads in each reference scenario. These incremental loads drive incremental infrastructure needs, as described in later sections of this document.

Figure 2: Potential annual load impact relative to reference scenarios



Relative to the Low Policy Reference, the proposed zero NOx standards could result in 6.2 TWh (terawatt-hours) per year of additional electric load by 2050. For comparison, California's 2020 electric load was approximately 280 TWh/year[6] and is modeled to grow to 338 TWh/year by 2045 in the Low Policy Reference.[7] Table 3 illustrates the potential impact of this additional load on statewide electric loads in 2020 and 2045.

Space heating has the largest contribution to these load impacts, with water heating also contributing a large share and air conditioning representing a small share of the load impact. The air conditioning load impact is much smaller than the other two end uses because air conditioning is already widespread in the warmest Bay Area counties.

[6] https://ecdms.energy.ca.gov/elecbycounty.aspx
[7] https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

Table 3: Potential impact of proposed standards on statewide electric load in 2020 and 2045.

Statewide Load	Low Policy Reference	Low Policy Reference + BAAQMD Proposed Standards
2020	280 TWh/year	280 TWh/year
2045	338 TWh/year (21% growth from 2020)	344 TWh/year (23% growth from 2020)

The impacts are different when considering the High Policy Reference. Relative to the High Policy Reference, the zero NOx standards result in *earlier* load growth, seeing 1.5 TWh/year of incremental load in the 2030s. However, the incremental load falls to near zero load impact by 2050 as heat pump adoption reaches high levels in the reference. Note that *negative* incremental load occurs in some years, meaning that the High Policy Reference scenario has higher loads in those years than loads modeled from the zero NOx standards.

Utility-Scale Solar Modeled to Meet Incremental Loads

Studies indicate that solar generation will be the predominant generation resource built to serve electric energy needs in California, although other zero-carbon resources are likely to be developed as well, potentially including land-based wind, offshore wind, geothermal, biomass, or other resources. This study modeled the impacts associated with the procurement of new utility-scale solar to meet all incremental heat pump loads. The following subsections provide more detail for this assumption.

Significant battery storage is also likely to be developed to meet generation capacity needs, as described below in the section **Generation Capacity**.

Zero-carbon Electricity to Meet New Loads

Although there is no state law requiring that new loads be met exclusively by zero-carbon electricity, the current resource planning paradigm requires electric utilities to procure zero-caron electricity on an annual basis corresponding to all new loads that can be reasonably forecast.

In California, utility resource planning occurs in the California Public Utilities Commission's (CPUC) Integrated Resource Planning process (IRP), where the CPUC reviews resource plans for both investor-owned utilities and community choice aggregators (CCAs).[8] In IRP, utilities and CCAs submit resource plans for how they will meet their load forecasts. Importantly, these resource plans are subject to a fixed GHG emissions cap. In the most recent phase of IRP, utilities submitted plans aligned with a 2030 electric-sector emissions cap of 38 million metric tons CO_2, which is understood to be aligned with the state's

[8] CCAs are local nonprofit public agencies that procure power on behalf of customers, with the incumbent utility (*e.g.,* PG&E) retaining responsibility for transmission and distribution infrastructure and for customer metering and billing. CCAs are widespread in the Bay Area, where they serve the majority of customer load.[11]

economywide emissions targets. Importantly, the same emissions cap was assumed across different sensitivities on load levels.[9] The IRP base case is planned to have some level of gas-powered generation that exactly meets the GHG emissions cap. Thus, any additional electric load from heat pumps would require incremental procurement of zero-carbon electricity so as not to increase gas generation and exceed the emissions cap.

More evidence that electrification loads will be met by zero-carbon resources comes from utility and CCA voluntary emissions targets. PG&E as well as many CCAs have committed to achieving certain emissions targets or 100% decarbonized portfolios regardless of load growth.[10] Although these targets may be for different years, they are aligned with the IRP planning paradigm that zero-carbon resources should be procured to serve new loads.

Municipal utilities such as the City of Palo Alto and Alameda Municipal Power are not subject to CPUC oversight in resource planning. However, these utilities make up less than 5% of electric load in the Bay Area.[11]

Utility-scale Solar as the Marginal Zero-carbon Generation Resource

Resource planning studies have considered the mix of new electric generation resources that will be developed in California. The IRP developed a Preferred System Plan that describes the optimal resource build through 2032. This plan includes the development of the following energy resources: 19 GW of utility-scale solar, 5 GW of land-based wind (including 1.5 GW out of state), 2 GW of offshore wind, 1 GW of geothermal, and 0.1 GW of biomass.[12] In addition, battery storage, pumped hydro storage, and demand response are developed to provide generation capacity.

While the IRP is focused on resource needs over the next decade, the 2021 “SB100 Joint Agency Report” considers resource needs through 2045.[13] This report documents a joint study by the California Energy Commission (CEC), CPUC, and CARB, investigating electric generation resource needs to meet the SB100 requirement that 100% of electric retail sales be from zero-carbon resources by 2045. Results of this study indicate that energy needs will be met through a mix of utility-scale solar, customer solar, land-based wind, and offshore wind, with utility-scale solar representing the majority of resource additions.[14]

Together, these studies indicate that utility-scale solar will be the predominant generation resource built to serve new loads in California, although some amount of land-based wind, offshore wind, geothermal, biomass, and/or other resources may also be developed. As a simplifying assumption, this study models

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[9] Figure 4 (p91) shows different load sensitivities modeled using the 38 million metric tons GHG cap in 2030. Other emission caps (46 MMT, 30 MMT) were considered but not adopted in this decision (Section 4.1, p72). https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF

[10] See targets for PG&E, East Bay Community Energy (Alameda County), MCE (Marin, Napa, Solano, Contra Costa), Clean Power SF (San Francisco County), and Peninsula Clean Energy (San Mateo County).

[11] See for example Form 1.1c of the California Energy Commission’s Integrated Energy Policy Report. https://efiling.energy.ca.gov/GetDocument.aspx?tn=241383&DocumentContentId=75340

[12] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF

[13] https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349

[14] See ref. 13, Figure 3

the impacts of utility-scale solar as the sole generation resource developed to serve potential new loads resulting from the proposed zero NOx standards.

Utility-scale Solar Impacts

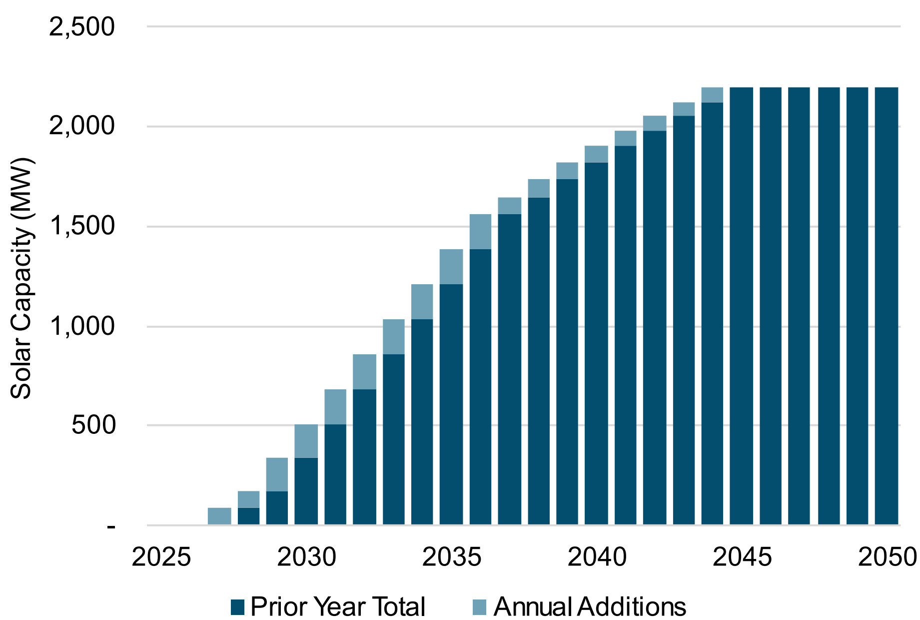
Note that this study does not aim to assess the total amount of solar generation needed to meet all customer loads. Rather, it aims to determine the additional solar generation needed to meet potential incremental loads from the proposed zero NOx standards beyond what would already be required in the reference scenarios.

The size of a solar power plant is described by its *nameplate capacity* and measured in MW (megawatts). The nameplate capacity describes the maximum potential output of the plant under optimal conditions. The average output from a solar plant is lower than the nameplate capacity and will depend on the plant's location and the technologies used. Solar technology characteristics used in the analysis are discussed in the section **Appendix: Detailed Methodology**.

Figure 3 shows the cumulative incremental solar capacity relative to the Low Policy Reference over time, breaking out the annual additions in each year. Relative to the Low Policy Counterfactual, 2,180 MW of incremental utility-scale solar capacity would be required by 2050. This amount of new solar capacity would generate 6.2 TWh/year of electricity, corresponding to the incremental loads relative to the Low Policy Reference (see Figure 2).

Relative to the High Policy Reference, 70 MW of incremental solar capacity would be needed by 2050.

Figure 3: Potential incremental utility-scale solar capacity relative to Low Policy Reference



As context for these incremental solar needs, the 2021 SB100 Joint Agency Report, described above, found that 70,000 MW of utility-scale solar capacity would be developed by 2045 in an optimal portfolio.[13]

Table 4 describes the potential 2050 utility-scale solar impacts from the proposed zero NOx standards. In addition to showing the potential impacts on solar capacity needs, Table 4 also describes the potential cost and land use impacts.

Table 4: Potential utility-scale solar impacts from proposed standards

	2050 impact relative to Low Policy Reference	**2050 impact relative to High Policy Reference**
Utility-Scale Solar (MW)	2180 MW	70 MW impact by 2050 *Accelerated impact in 2030s, 2040s*
Cumulative Cost (Real $2021 Million)	$1,860	$390 *Due to accelerated build*
Land Use (acres)	19,500	700

The costs in this table are calculated based on annual incremental load impacts and the levelized cost of energy (LCOE) of utility-scale solar, as described in the section **Appendix: Detailed Methodology**. Costs reported here reflect cumulative costs through 2050, incremental to the Reference.

To evaluate the land use impacts associated with utility-scale solar, E3 drew on an NREL report that evaluated the direct land use impacts of solar, *i.e.*, the land directly occupied by solar project infrastructure.[15] The study found the direct land-use impact of utility-scale solar to be 9.0 acres per MW. The incremental utility-scale solar needs described above correspond to direct land use impacts of 79 km^2 (19,500 acres) relative to the Low Policy Reference, and 3 km^2 (700 acres) relative to the High Policy Reference. For more details on NREL report, see the section **Appendix: Detailed Methodology**.

The land requirements of renewable generation resources are well understood, and environmental restrictions on renewable project siting are an active topic of discussion among policymakers and stakeholders. In 2019, The Nature Conservancy published a report called “The Power of Place,” which considered the land impacts of renewable generation needed to achieve California’s climate goals and evaluated scenarios with different environmental exclusions for renewable development.[16] Across the scenarios evaluated, the study found 1.6 million to 3.1 million acres of land would be developed by 2050 for solar and wind generation.[17]

The report also explored where in-state resources may be developed, indicating that utility-scale solar development would likely focus in areas of high solar resource quality in the Central Valley, Inland Empire, and Mojave Desert, with little to no utility-scale solar development within the Bay Area.[18] The CPUC has also evaluated where new resources are likely to be developed on a ten-year timeframe, indicating similar

[15] https://www.nrel.gov/docs/fy13osti/56290.pdf
[16] https://www.scienceforconservation.org/products/power-of-place
[17] See p6, https://www.scienceforconservation.org/assets/downloads/Executive_Summary_Power_of_Place.pdf
[18] See figure 9, https://www.scienceforconservation.org/assets/downloads/Technical_Report_Power_of_Place.pdf

in-state locations for utility-scale development as well as some out-of-state locations in Arizona and Nevada.[19]

[19] See figure 1, https://files.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2022-2023_TPP_V.2022-2-7.pdf

5. Capacity-Related Impacts and Infrastructure Needs

Capacity Impact Methodology

County-level Load Disaggregation

For this section of the analysis, annual load impacts were disaggregated to the nine Bay Area counties. There are two reasons why this disaggregation was done:

- Different hourly load shapes were used for each county, as described in more detail in the section **End-Use Load Profiles**.
- Different distribution capacity avoided costs were used for each county based on the corresponding CEC climate zone, as described in more detail in the section **Evaluating Capacity Impacts**.

More details of this load disaggregation are provided in the section **Appendix: Detailed Methodology**. County-level impacts have not been calculated in this study. All results are provided for the full BAAQMD territory, with the county-level loads used as an intermediate step to reflect the distinctions in load shapes and distribution capacity avoided costs across the Bay Area counties.

End-Use Load Profiles

Hourly end-use load profiles were developed based on building simulations from the NREL ResStock and ComStock databases.[20] These databases contain building energy simulation data for the entire US, evaluated with county-level weather data and broken out by census tract. The goal of the databases is to approximately represent the entire US building stock through hourly simulations of building loads.

More details on the load profiles are provided in the section **Appendix: Detailed Methodology.**

Evaluating Capacity Impacts

E3 leveraged the California Public Utility Commission's (CPUC's) 2021 Avoided Cost Calculator (ACC) to calculate the potential impacts of incremental heat pump loads on generation capacity, transmission capacity, and distribution capacity. The Avoided Cost Calculator (ACC) is a spreadsheet model designed to evaluate the impacts of distributed energy resources on the grid.[21] Although initially developed to evaluate programs that reduce load, the ACC is increasingly being used to evaluate the marginal costs and benefits of load growth measures, including building and vehicle electrification. E3 maintains the ACC on behalf of the CPUC.

The ACC provides hourly marginal costs for generation capacity, transmission capacity, and distribution capacity, reflecting how capacity costs in each category are allocated over peak hours where load growth

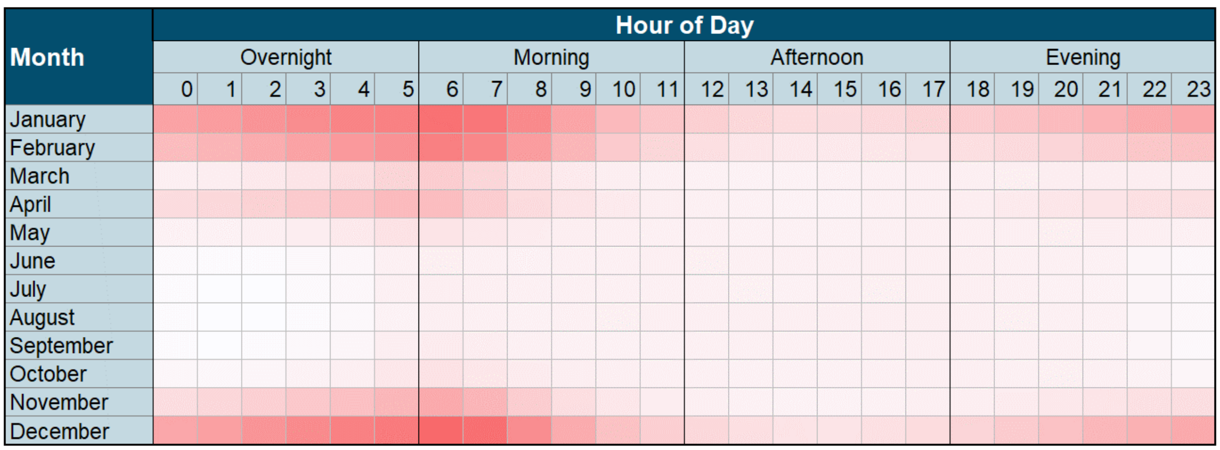
[20] https://resstock.nrel.gov/, https://comstock.nrel.gov/
[21] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm

would drive a need for new investment. The ACC reflects distinct peak hours for generation capacity, transmission capacity, and distribution capacity, with distribution capacity further differentiated among climate zones within California.

Hourly Load Impacts

Figure 4 shows the hourly distribution of potential load impacts by 2050 relative to the Low Policy Reference. This figure shows how the 6.2 TWh/year of additional loads would be distributed over the months of the year (vertical) and hours of the day (horizontal). Due to the timing of space heating loads, the largest potential load impacts are calculated to be in winter night and morning hours.

Figure 4: Heat map showing the distribution of potential 2050 load impacts relative to Low Policy Reference



Capacity-Related Infrastructure Needs

Generation Capacity

Table 5: Potential generation capacity impacts from proposed standards

	2050 impact relative to Low Policy Reference	**2050 impact relative to High Policy Reference**
Generation Capacity (MW)	410 MW	< 10 MW impact by 2050 *Accelerated impact in 2030s, 2040s*
4-Hour Battery Storage (MW)	680 MW	< 10 MW impact by 2050 *Accelerated impact in 2030s, 2040s*
Cumulative Cost (Real $2021 Million)	$90	$30 *Due to accelerated build*
Land Use (acres)	8	< 0.1

Table 5 describes the potential 2050 generation capacity impacts associated with the proposed zero NOx standards. Generation capacity describes the need for generation resources to serve electricity needs at times of peak demand. Because California's electric system peaks in summer afternoons and evenings, only load impacts in those hours contribute to generation capacity needs.

Relative to the Low Policy Reference, potential heat pump adoption under the proposed standards would lead to 410 MW of additional generation capacity need by 2050. This describes the need for "perfect capacity," *i.e.*, capacity of an idealized perfectly firm resource that never suffers outages. The ACC assumes that 4-hour batteries will be the marginal resource to provide generation capacity, but forecasts that the capacity contribution of these batteries will fall to 60% by 2050.[22] As a result, 680 MW (nameplate capacity) of 4-hour batteries would be required to provide 410 MW of (perfect) generation capacity.

Battery storage costs are also estimated based on the ACC. Battery costs in the ACC reflect that investments in utility-scale batteries would be financed over the lifetime of the assets. Costs reported here reflect cumulative payments through 2050 on financed battery storage systems, incremental to the Reference.

Utility-scale batteries are containerized systems and have much smaller land impacts than utility-scale solar. Using specifications for the Tesla Megapack battery,[23] 680 MW of battery storage would have an 8-acre footprint.

[22] Details in the 2021 ACC documentation (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2021-acc-documentation-v1b.pdf) and model (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2021-acc-electric-model-v1b.xlsb)

[23] https://www.tesla.com/blog/introducing-megapack-utility-scale-energy-storage

Relative to the High Policy Reference, there is an accelerated need for generation capacity in the 2030s and 2040s but only a negligible capacity impact (< 10 MW) and land impact (<0.1 acres) by 2050.

As context for these battery storage needs, the SB100 Joint Agency Report indicates that 49,000 MW of battery storage capacity would be built in California by 2045 as part of an optimal resource portfolio.[24]

Transmission Capacity

Table 6: Potential transmission capacity impacts from proposed standards

	2050 impact relative to Low Policy Reference	2050 impact relative to High Policy Reference
Transmission Capacity (MW)	460 MW	< 1 MW impact by 2050 *Accelerated impact in 2030s, 2040s*
Cumulative Cost (Real $2021 Million)	$100	$25 *Due to accelerated build*
Associated infrastructure	Costs reflect one transformer upgrade **or** 10-20% of a 100-mile transmission project	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*

Table 6 describes the potential 2050 transmission capacity impacts associated with the proposed zero NOx standards. Transmission capacity describes the need for new transmission investments to support increased peak loads on the transmission system. Because California's electric system peaks in summer afternoons and evenings, only load impacts in those hours contribute to transmission capacity needs.

This analysis finds that, relative to the Low Policy Reference, potential heat pump adoption under the proposed standards would require infrastructure to support 460 MW of incremental transmission capacity need by 2050. Relative to the High Policy Reference, there is an accelerated need for transmission capacity in the 2030s and 2040s but only a negligible capacity impact (< 1 MW) and infrastructure impact by 2050.

Transmission costs are also estimated based on the ACC. Transmission costs in the ACC reflect that utility investments in transmission would be financed by an electric utility and recovered from ratepayers over the lifetime of the asset. Costs reported here reflect cumulative ratepayer costs through 2050, incremental to the Reference.

There is not a simple picture of what infrastructure would be required to provide 460 MW of transmission capacity (incremental to the Low Policy Reference). As shown in Table 6, this transmission capacity would come at a cumulative cost of $100 million in real (inflation-adjusted) 2021 dollars. This cost estimate can be used to understand the scope of investment needed to provide this level of transmission capacity.

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

Projects to increase transmission capacity are generally expensive large-scale projects and may cost hundreds of millions or billions of dollars. Thus, the transmission capacity impacts described here may reflect the need for only a fraction of a transmission project. To understand these infrastructure impacts, E3 considered the CA Independent System Operator (CAISO) 20-Year Transmission Outlook, a document that considers transmission needs over the next 20 years to meet load and renewable energy growth aligned with state policy.[25] This plan describes $11 billion in upgrades to the existing CAISO transmission footprint over the 20-year timeframe. Based on the project details included in the study, the $100 million additional transmission system costs relative to the Low Policy Reference would correspond to a single transformer upgrade *or* 10-20% of the project cost associated with a 100-mile transmission project.

The $11 billion figure also provides a reference point to understand the scale of transmission investments that are forecast over the next two decades in the CAISO footprint, which covers ~80% of California's electric load.

[25] http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf

Distribution Capacity

Table 7: Potential distribution capacity impacts from proposed standards

	2050 impact relative to Low Policy Reference	2050 impact relative to High Policy Reference
Distribution Capacity (MW)	420 MW	< 10 MW impact by 2050 *Accelerated impact in 2030s, 2040s*
Cumulative Cost (Real $2021 Million)	$380	$100 *Due to accelerated build*
Estimated Banks (New, by 2050)	6 New Banks	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*
Estimated Feeders (New, by 2050)	45 New Feeders	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*
Estimated Line Sections (New, by 2050)	10 New Line Section	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*
Estimated Banks (Upgrades, by 2050)	31 Bank Upgrades	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*
Estimated Feeders (Upgrades, by 2050)	42 Feeder Upgrades	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*
Estimated Line Sections (Upgrades, by 2050)	35 Line Section Upgrades	Negligible impact by 2050 *Accelerated impact in 2030s, 2040s*

Table 7 summarizes the potential distribution infrastructure needs estimated to result from the proposed zero NOx standards from 2026 through 2050. Distribution capacity describes the need for investments to support increased peak loads on the distribution system. While generation capacity and transmission capacity needs are only triggered by summer afternoon and evening loads, the ACC indicates that distribution capacity needs may be affected by loads across a broader set of hours in all four seasons. In addition, distribution capacity costs and peak hours used in this study are differentiated by CEC climate zone.

This analysis finds that potential growth from heat pump adoption would result in incremental distribution capacity requirements of 420 MW by 2050 relative to the Low Policy Reference. As with transmission capacity, the associated infrastructure needs can be evaluated by considering the associated cost of distribution capacity. The 420 MW of distribution capacity needs reflect a cumulative (simple sum) cost of $380 million by 2050 (real 2021 dollars).

Relative to the High Policy Reference, there is an accelerated need for distribution capacity in the 2030s and 2040s but only a negligible capacity impact (< 10 MW) and cost impact by 2050.

Distribution costs are also estimated based on the ACC. Distribution costs in the ACC reflect that utility investments in distribution would be financed by an electric utility and recovered from ratepayers over the lifetime of the asset. Costs reported here reflect cumulative ratepayer costs through 2050, incremental to the Reference.

Utility spending on distribution capacity reflects various infrastructure projects to accommodate increased peak loads on the system. Distribution infrastructure projects range from upgrades or replacements of existing equipment, which occur in existing rights of way, to greenfield construction of new line sections, distribution feeders, or substations, which may have a more significant environmental impact. For this study, E3 used the planned investments in PG&E's 2021 Distribution Deferral Opportunities Report (DDOR) filing[26] to evaluate how distribution capacity costs may be invested into distribution infrastructure projects. The list of projects in the DDOR was categorized according to whether projects represented new build or upgrades, and then further divided into three general project categories: distribution banks, feeders, and line sections. The costs of these projects were used to estimate the number and type of projects built per million dollars of distribution-system investment. The project counts shown in Table 7 reflect, in aggregate, an estimate of how $380 million may be spent on distribution-system infrastructure.

As a point of reference for these distribution-system cost estimates, the 2021 DDOR reflects $400 million *per year* in distribution capacity-related costs in PG&E's service territory, covering ~30% of statewide load.

[26] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M400/K593/400593924.PDF

6. Conclusion

This study evaluated the electric grid impacts of heat pump adoption that could result from the proposed zero NOx standards. The results indicate that the potential electric grid impacts of the proposed zero NOx standards are highly dependent on what other policies California enacts around building electrification to meet the state's climate goals.

Relative to the Low Policy Reference, a scenario where the state's climate goals are not met, the proposed standards would result in incremental load impacts, capacity impacts, and infrastructure impacts by 2050. The Low Policy Reference only assumes existing policies and incentives to support building electrification and reflects a future in which California fails to meet our climate targets. Thus, these results provide a conservative upper-bound estimate of the impacts that could be attributed to the proposed zero NOx standards.

Conversely, relative to the High Policy Reference, a scenario in line with achieving the state's climate goals, the proposed standards would result in some acceleration of grid impacts, but almost no net impacts by 2050. This reflects future state policies assumed in the High Policy Reference would result in near-100% heat pump adoption as well as significant electric grid impacts by 2050, even without the proposed zero NOx standards.

7. Appendix: Sensitivities on Implementation Year

Sensitivity 1: Zero NOx standards take effect in 2026

In this sensitivity, all zero NOx standards are assumed to take effect January 1, 2026. As in the main analysis, this sensitivity assumes that only 50% of gas used for commercial water heating would be covered by the zero NOx standards.

Figure 5 illustrates the load impacts for this sensitivity. Compared to the main analysis (Figure 2), load impacts begin earlier due to the earlier implementation of the zero NOx standards.

Figure 5: Potential annual load impact relative to reference scenarios (sensitivity 1)

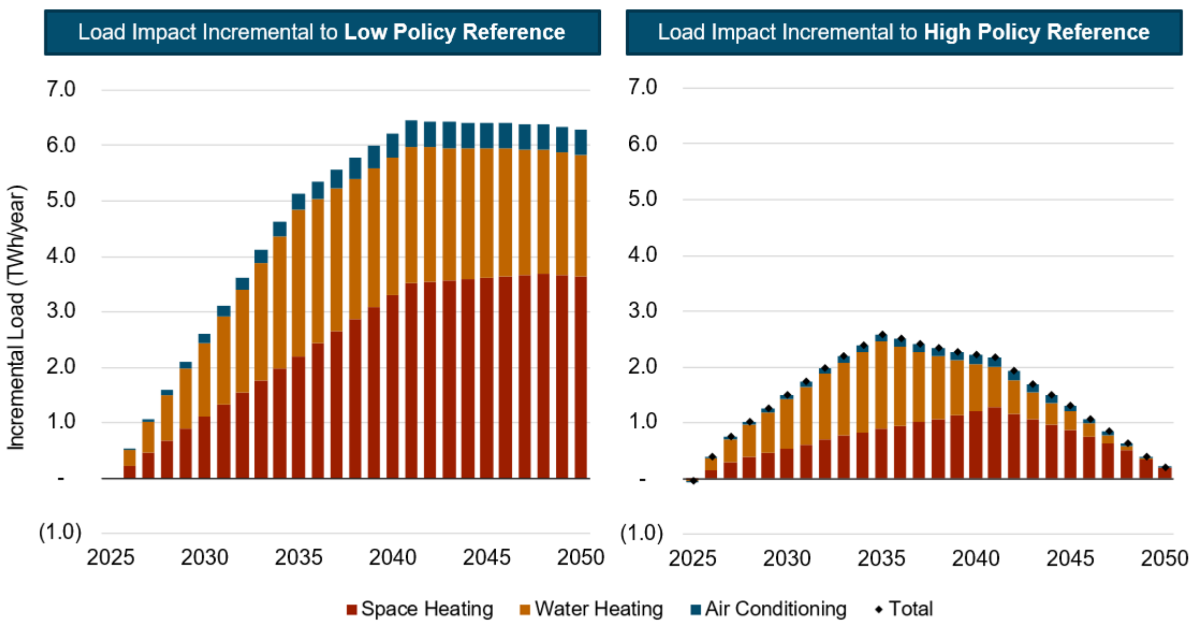


Table 8 provides a summary of 2050 electric grid impacts in this sensitivity. Compared to the main analysis (Table 1), implementing the zero NOx standards in 2026 would accelerate electric grid impacts but would result in similar overall impacts by the year 2050. This is because, even with the proposed zero NOx standard applicable dates from 2027-2031, nearly 100% of customers would have heat pumps installed by 2050.

Table 8: Summary of potential 2050 electric grid impacts of zero NOx standards (sensitivity 1)

	Impact relative to Low Policy Reference	Impact relative to High Policy Reference
Utility-scale solar *to serve electric loads*	2,240 MW new solar by 2050	120 MW new solar by 2050 *+ accelerated build in 2030s & 2040s*
4-hour battery storage *for generation capacity*	700 MW new batteries by 2050	< 10 MW new batteries by 2050 *+ accelerated build in 2030s & 2040s*
Transmission Capacity	460 MW impact by 2050	< 10 MW impact by 2050 *+ accelerated build in 2030s & 2040s*
Distribution Capacity	440 MW impact by 2050	< 10 MW impact by 2050 *+ accelerated build in 2030s & 2040s*

Sensitivity 2: Zero NOx standards take effect in 2035.

In this sensitivity, all zero NOx standards are assumed to take effect January 1, 2035. As in the main analysis, this sensitivity assumes that only 50% of gas used for commercial water heating would be covered by the zero NOx standards.

Figure 6 illustrates the load impacts for this sensitivity. Compared to the main analysis (Figure 2), load impacts begin later due to the later implementation of the zero NOx standards.

Figure 6: Potential annual load impact relative to reference scenarios (sensitivity 2)

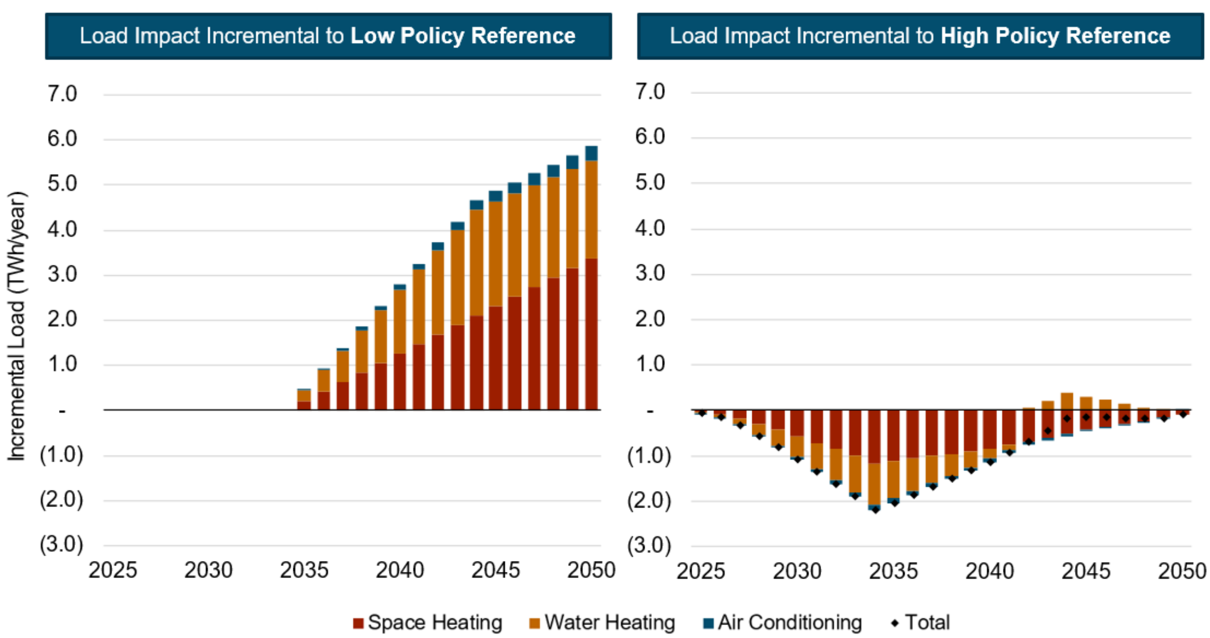


Table 9 provides a summary of 2050 electric grid impacts in this sensitivity. Compared to the main analysis (Table 1), implementing the zero NOx standards in 2035 would delay electric grid impacts and would result in 5-10% smaller impacts by the year 2050. Based on the device lifetimes used in this analysis, implementing the standards in 2035 would still result in 100% adoption levels for residential heat pumps as well as commercial heat pump water heaters by 2050, with only commercial space heating not achieving 100% adoption by 2050.

Table 9: Summary of potential 2050 electric grid impacts of zero NOx standards (sensitivity 2)

	Impact relative to Low Policy Reference	**Impact relative to High Policy Reference**
Utility-scale solar *to serve electric loads*	2,010 MW new solar by 2050	-60 MW new solar by 2050 *(less need than in reference)*
4-hour battery storage *for generation capacity*	650 MW new batteries by 2050	~0 new batteries by 2050 *(less need than in reference)*
Transmission Capacity	420 MW impact by 2050	~0 MW impact by 2050 *(less need than in reference)*
Distribution Capacity	390 MW impact by 2050	~0 MW impact by 2050 *(less need than in reference)*

8. Appendix: Detailed Methodology

Technology Assumptions

Table 10 illustrates modeling assumptions for baseline gas technologies. Device lifetime and performance metrics are based on representative building equipment data from the Energy Information Administration (EIA).[27] Where lifetime ranges were provided by EIA, E3 selected a conservative (short) lifetime from within the range.

Table 10: Baseline gas technologies modeled for each end use

End use	Representative technology	Device Lifetime (years)
Residential Space Heating	Gas furnace	16
Residential Water Heating	Gas storage water heater	10
Commercial Space Heating	Gas furnace or rooftop unit	23
Commercial Water Heating	Gas storage water heater	10

For the heat pumps that could replace these gas devices, assumptions regarding performance for water heating and air conditioning are also based on EIA data.[27] For space heating performance, E3 modeled high-end heat pumps in today's market, which are meant to reflect representative technologies that would be installed in the late 2020s and beyond.

Reference Scenarios

Although the CARB scenarios reflect statewide adoption, they were used as-are for this work due to the lack of available forecasts specifically for the Bay Area. The electric load impacts developed in this study are based on the adoption *trajectories* rather than *absolute adoption levels* and are benchmarked to 2019 gas usage data for BAAQMD's territory. Thus, the load impacts developed in this study should be reflective of the Bay Area even if CARB's statewide scenarios do not reflect the absolute levels of heat pump adoption in the region.

[27] https://www.eia.gov/analysis/studies/buildings/equipcosts/

In addition, the CARB scenarios were only provided through 2045. As this analysis was performed through 2050, the Low Policy and High Policy Reference scenarios were extrapolated through 2050 using an exponential smoothing algorithm.

Sales share and stock share trajectories for residential heat pump space heating is presented in the section **Reference Scenarios and Proposed Standards Scenario**. The following figures present the potential sales share and stock share for residential heat pump water heating (Figure 7), commercial heat pump space heating (Figure 8), and commercial heat pump water heating (Figure 9).

Figure 7: Potential sales share (left) and stock share (right) for residential heat pump water heating

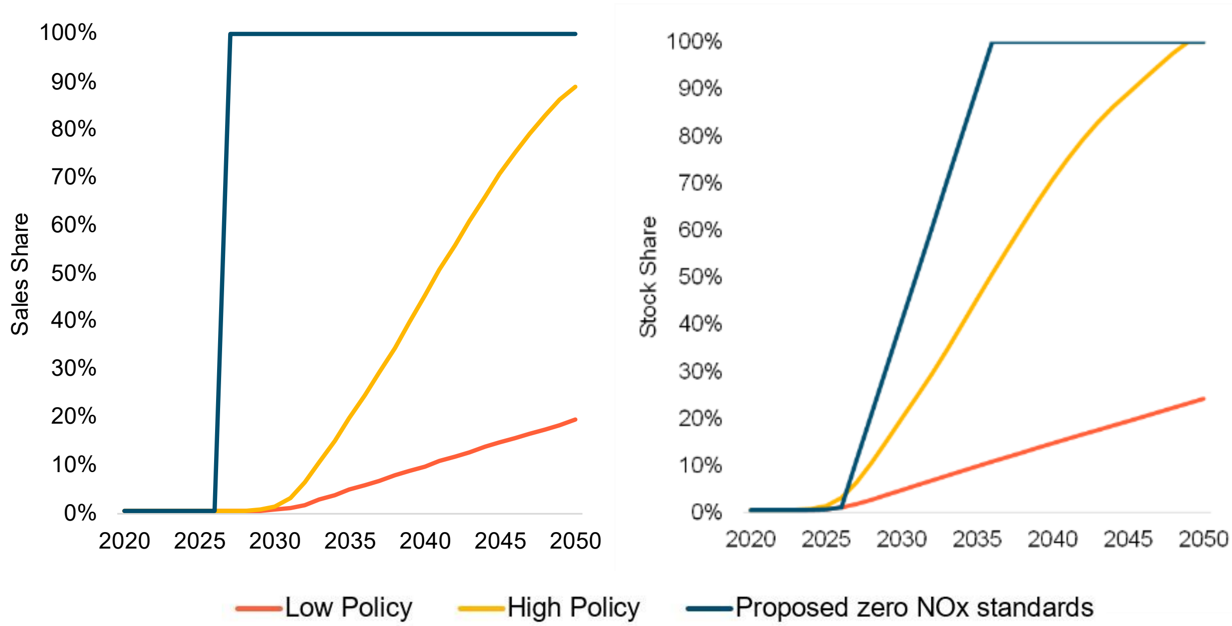


Figure 8: Potential sales share (left) and stock share (right) for commercial heat pump space heating

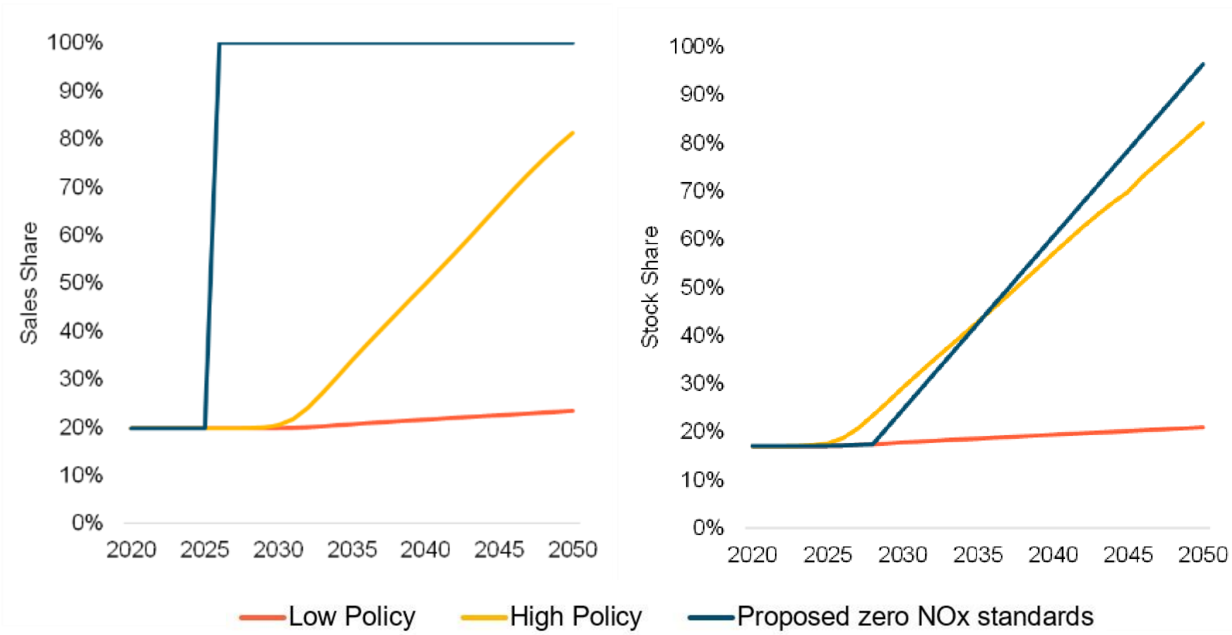
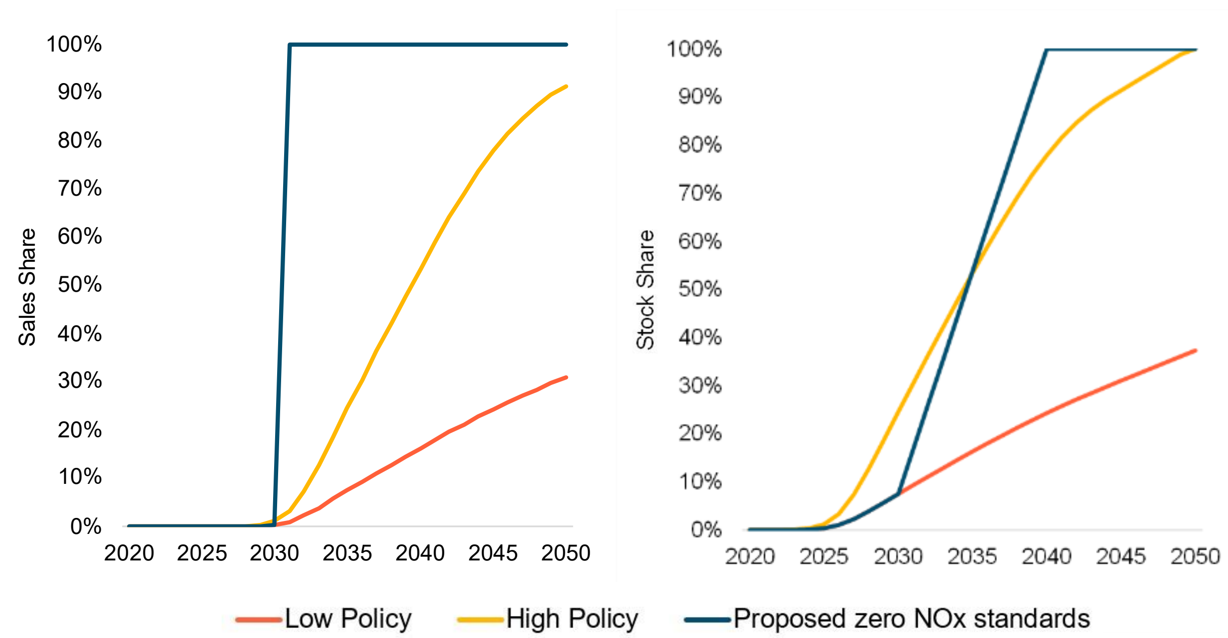


Figure 9: Potential sales share (left) and stock share (right) for commercial heat pump water heating



Air Conditioning Loads

To estimate current levels of residential AC adoption, E3 used data from the CEC's 2019 Residential Appliance Saturation Survey[28] (RASS) on AC adoption by CEC climate zone among homes in PG&E's gas service territory. Each of the nine Bay Area counties was assigned to one CA climate zone as illustrated in Table 11 above.

To estimate future residential AC adoption in the reference scenarios, E3 compared AC saturation data for the same set of buildings (pre-2000 vintage) between the 2009 and 2019 vintages of the RASS.[29] This enabled the development of a decadal AC adoption rate for each climate zone. Note that this does not reflect potential for the acceleration of AC adoption due to climate change or other factors. However, this does reflect a conservative (upper end) assumption for the potential for AC load growth due specifically to heat pump adoption.

Commercial buildings were assumed to already have 100% AC adoption. Although some smaller commercial building may not have air conditioning, this assumption reflects that the largest energy users among commercial buildings are likely to already have air conditioning.

Finally, average per-building air conditioning loads were calculated from the National Renewable Energy Laboratory (NREL) ResStock and Comstock databases.[30] Average annual AC load was calculated among residential buildings and commercial buildings that currently have AC in each Bay Area county. Residential buildings without AC that install a heat pump were assumed to add slightly less than the average per-building AC load. Residential buildings with AC that install a heat pump were assumed to slightly reduce their AC load.

Solar Technology Modeling

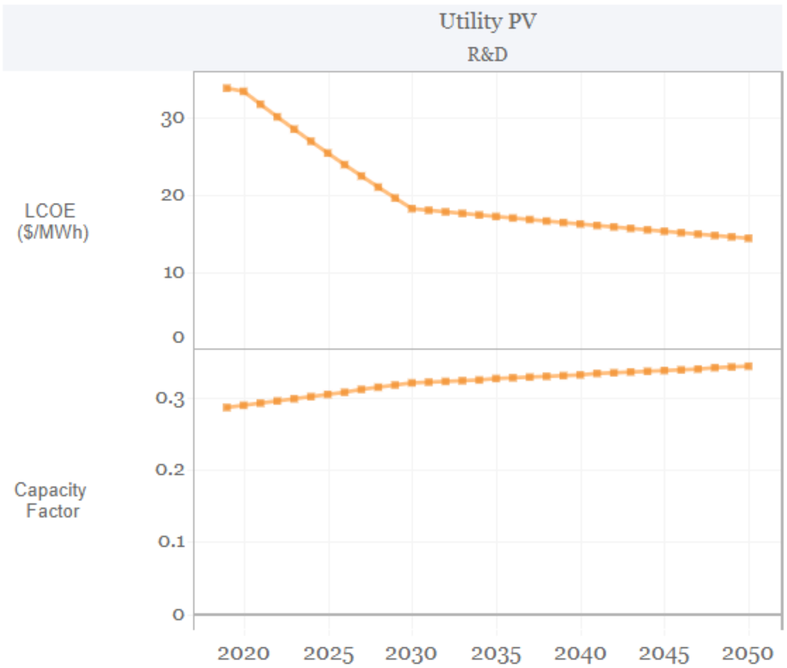
In this modeling, cost and performance data for solar generation come from the National Renewable Energy Laboratory's 2021 Annual Technology Baseline (NREL ATB), which provides standardized forecasts of energy technology development over time.[31] The modeling uses the "Moderate" technology development trajectory for "Class 3 Utility-Scale PV." (PV, or photovoltaic, reflects the main technology used in solar electricity generation). The specific data used are Levelized Cost Of Electricity (LCOE), which reflects the cost of solar energy, and capacity factor, which reflect the average amount of energy produced by 1 MW of solar capacity. These data are shown in Figure 10.

Both cost and capacity factor are forecast to steadily improve, with LCOE falling and capacity factor increasing over time. Our modeling assumes that new solar is built to serve incremental energy needs in every year, using each year's solar cost and capacity factor. As a result, some amount of incremental

[28] https://www.energy.ca.gov/sites/default/files/2021-08/CEC-200-2021-005-ES.pdf
[29] https://webtools.dnv.com/CA_RASS/Default.aspx
[30] https://resstock.nrel.gov/, https://comstock.nrel.gov/
[31] https://atb.nrel.gov/electricity/2021/utility-scale_pv

energy need in 2030 would result in greater solar capacity impacts and greater cost impacts (in real dollars) than a need for the same amount of energy in 2040.

Figure 10: Solar LCOE and capacity factor over time, from NREL ATB



Land density for utility-scale solar is modeled as 27.5 MW / km^2 based on the 2013 NREL report "Land-Use Requirements for Solar Power Plants in the United States."[32] This report estimates both the *total* and *direct* land area required for solar generation projects in the US, explaining: "The total area corresponds to all land enclosed by the site boundary. The direct area comprises land directly occupied by solar arrays, access roads, substations, service buildings, and other infrastructure." This study uses the *direct* area required for "Large PV" (*i.e.*, utility-scale) and assumes that 1-axis tracking systems are used.[33] The report's figure of 9.0 acres / MW corresponds to 27.5 MW / km^2.

County-level Load Disaggregation

County-level loads were disaggregated using data from the 2019 American Community Survey (ACS),[34] which reports the number of households with gas space heating for each census tract in California. E3 considered census tracts subject to the proposed standards if the centroid of the census tract fell within the boundaries of the BAAQMD territory, as delineated in a shapefile provided to E3 by BAAQMD. Covered

[32] https://www.nrel.gov/docs/fy13osti/56290.pdf
[33] Based on the 2021 early release data from EIA-860, 76% of utility-scale solar generation capacity in CA currently uses 1-axis tracking. https://www.eia.gov/electricity/data/eia860/
[34] See https://www.census.gov/programs-surveys/acs/data.html

census tracts were aggregated to the county level to determine the number of gas-heated residential buildings in each county that would be covered by the proposed standards.

Table 11 shows the numbers of gas-heated households covered by BAAQMD. These figures were used to allocate the total load impacts for residential and commercial space and water heating over the nine Bay Area counties. In addition, each county was assigned to a single CEC Title 24 Climate Zone meant to reflect most of the buildings within that county.

This is a coarse methodology for load disaggregation and county-level results have not been calculated. All results are provided for the full BAAQMD territory, with the county-level loads used as an intermediate step to reflect the distinctions in load shapes and distribution capacity avoided costs across the Bay Area counties.

Table 11: Number of gas-heated households per county in BAAQMD territory and assigned climate zones

County	Gas-Heated Households	Climate Zone
Alameda	397,155	3
Contra Costa	270,465	12
Marin	73,325	2
Napa	31,191	2
San Francisco	214,061	3
San Mateo	174,341	3
Santa Clara	295,819	4
Solano	72,262	12
Sonoma	113,004	2

End Use Load Profiles

A five-step approach was used to develop heat pump load profiles for this study.

1. Space heating, water heating, and space cooling load profiles from ResStock and ComStock were aggregated for each of the nine Bay Area counties. To reflect energy demands for buildings that currently use gas for space and water heating, E3 utilized hourly load profiles corresponding to natural gas usage for those end uses.
2. To maintain accurate correlation between weather and energy usage, E3 developed a random forest regression model to map load simulations from the NREL databases onto the standardized weather data used in the Avoided Cost Calculator. Random forest models are popular for regression

modelling of electric loads as they provide reasonable results with minimal parameter tuning.[35,36] The model was validated using ResStock and ComStock simulations performed on two different sets of weather data.

3. Heat pump performance varies as a function of outdoor air temperature. E3 considered a high-end heat pump in today's market and reflective of representative technologies that would be installed in the 2030s. Using this technology and associated weather data, the hourly natural gas load profiles were converted into corresponding heat pump electric load profiles.
4. Load profiles were normalized by dividing by the sum of loads over the year. This results in normalized load profiles for each end use and each county, aligned with the weather data used in the Avoided Cost Calculator.
5. For each end use, normalized load profiles were multiplied by the annual load impacts allocated to each county. This results in county-level hourly load impacts for each end use and year.

[35] https://www.researchgate.net/publication/280555451_Random_forests_model_for_one_day_ahead_load_forecasting
[36] https://res.mdpi.com/d_attachment/algorithms/algorithms-13-00274/article_deploy/algorithms-13-00274.pdf