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Time Dependent Valuation of Energy for Developing Building Efficiency Standards

2022 Time Dependent Valuation (TDV) and Source Energy Metric Data Sources and Inputs

May 2020

Energy+Environmental Economics

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Submitted to Adrian Ownby

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Contents Overview

This report describes data sources, calculations and results used in the 2022 Time Dependent Valuation (TDV) update for the 2022 Title 24 building standards. The 2022 Title 24 building standards will go into effect January 1, 2023 and be in effect for 3 years until the next cyclical update for the 2025 Title 24 building standards. This report reflects the TDV values included in the excel file named "2022_TDV_CH4_Leak_20yr_15RA_20200422.xlsx", and source energy values included in "2022_TDV_Source_Energy_CH4_Leak_20yr_15RA_20200422.xlsx".

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1 Background and Approach

1.1 Principals and Purpose of TDVs and Source Energy Metric

The Title 24 building standards are developed based upon the cost-effectiveness of energy efficiency measures in new buildings in California. The standards promote measures that have a positive benefit-cost ratio from a modified participant cost perspective. The Title 24 standards allow building designers to make trade-offs between energy saving measures using building simulation tools that evaluate the energy performance of proposed building designs.

Beginning with the 2005 standards update, time-dependent valuation (TDV) has been used in the cost-effectiveness calculation for Title 24. The concept behind TDV is that energy efficiency measure savings should be valued differently depending on which hours of the year the savings occur, to better reflect the actual costs of energy to consumers, to the utility system, and to society. The TDV method encourages building designers to design buildings that perform better during periods of high energy cost. Prior to 2005, the value of energy efficiency measure savings had been calculated on the basis of a "flat" source energy cost. Since the 2016 TDV update, the hourly TDV factors are also correlated with the statewide typical weather files used in building simulation tools.

The economics for the 2022 Title 24 Building Energy Efficiency Standard TDVs, like those developed for the 2008, 2013, 2016, and 2019 T24 updates, are based on long-term (15- and 30-year) forecasts that reflect existing energy trends and state policies. The timeframe of the economic analysis used in the 2022 TDVs spans the years 2023 to 2052 for the 30-year analysis and 2023 to 2037 for the 15-year analysis. TDV NPV costs are reported in 2022 dollars and are formatted to the 2009 calendar year and TMY weather year file data.

In the 2022 code cycle, an hourly source energy metric has been introduced as a secondary performance metric to complement TDV. TDV will remain as the basis of cost-effectiveness calculations for proposed building designs and will continue to be used as a performance metric for building designs.

Source energy provides a secondary performance metric that is a more direct measure of environmental benefits of proposed building designs.

This report has been developed to document the methodology used to compute the 2022 TDV factors and hourly source energy metric used in Title 24. The basic concepts and approach used to develop the TDV methodology are the following:

1. **Rational and Repeatable Methods**

   We have used published and public data sources for the fundamental analysis approach to developing TDV data. This allows revisions of the Standards and their underlying TDV data to be readily updated when called for by the California Energy Commission (CEC).

2. **Based on Hourly (or Monthly) Cost of Energy, Increased to Retail Rate Levels**

   TDV is based on a series of annual hourly values for electricity cost (and monthly costs for natural gas and propane) in the typical CEC weather year. TDV values are developed for each of the sixteen climate zones, for residential and for nonresidential buildings. Starting with these hourly electricity costs, the TDV then includes an adjustment so that the annual average of the hourly TDV values are equivalent on an average annual basis to the residential and nonresidential statewide average retail rate forecasts.

3. **Seamless Integration within Title 24 Compliance Methods**

   The mechanics of TDV should be transparent to the user community and compliance methods should remain familiar and easy. TDV factors are represented in kWh/Btu or therms/Btu units, consistent with the previously used source energy approach and the 2008, 2013, 2016 and 2019 TDV updates.

4. **Climate Zone Sensitive**

   As with the weather data used for Title 24 performance calculations, which allow building designs to be climate responsive, the TDV methodology also reflects differences in costs driven by climate conditions. For example, an extreme, hot climate zone has higher, more concentrated peak energy costs than a milder, less variable climate zone.

5. Components of TDV

The TDV method develops each hour's (or month's) energy valuation using a bottom-up approach. We sum together the individual components of the cost of energy and then scale up the values such that over the course of the year the values are equal the average retail price for residential and non-residential customers. The resulting electricity TDV factors vary by hour of day, day of week, and time of year. The key components of the electricity TDV factors are summarized below:

- Marginal Cost of Electricity – *variable by hour* – The shape of the hourly marginal cost of generation is developed using the Commission's PLEXOS production simulation dispatch model (developed by Energy Exemplar). The price shape from the production simulation model is then adjusted to reflect the natural gas price forecast as well as the following non-energy costs of energy: transmission & distribution costs, emissions costs, ancillary services and peak capacity costs.
- Revenue neutrality adjustment – *fixed cost per hour* – The remaining, fixed components of total annual utility costs that go into retail rates (taxes, metering, billing costs, etc.) are then calculated and spread out over all hours of the year. In the 2022 code cycle, 85% of the adjustment is a flat uniform adder and 15% is scaled by the marginal cost of service, to provide stronger dispatch signals to dispatchable DERs[1]. The result, when added to the hourly marginal cost of electricity, is an annual total electricity cost valuation that corresponds to the total electricity revenue requirement of the utilities.

While the details of the Title 24 TDV methodology can be complex, at root the concept of TDV is quite simple. It holds the total cost of energy constant at forecasted retail price levels but gives more weight to on-peak hours and less weight to off-peak hours. This means that energy efficiency measures that perform better on-peak will be valued more highly than measures that do not.

[1] Note: this is a change from previous TDV code cycles where the retail rate adjustment was spread evenly across all hours, as a flat uniform adjustment. Subsequent sections will describe this change in more detail.

1.2 TDV Frequently Asked Questions

1. What is Time Dependent Valuation (TDV)?

    - TDV is the cost-effectiveness and energy valuation methodology used in development and implementation of the Title 24 Building code. The TDV of energy is a participant cost effectiveness metric to evaluate whether a Title 24 measure will save consumers money on their utility bill over the life of a new building. The values of TDV are constructed from a long-term forecast of hourly electricity, natural gas and propane costs to building owners consistent with the latest CEC forecasts and outlook for California's energy sectors. The time dependent nature of TDV reflects the underlying marginal cost of producing and delivering an additional unit of energy, similar to a time of use retail tariff, and the resulting economic signal aligns energy savings in buildings with the cost of producing and delivering energy to consumers.

2. How is TDV used?

    - The Energy Commission uses TDV in its California Building Energy Code Compliance software to set the target energy budgets for newly constructed buildings, and to value the design trade-offs made during the development and construction of those buildings. The TDV metric determines (in part) the long-term cost effectiveness of proposed energy efficiency measures. TDV is the metric adopted in the Integrated Energy Policy Report for the measurement of zero net energy (ZNE) buildings.

3. Why is TDV biased in favor of natural gas for space and water heating?

    - TDV is a participant cost effectiveness metric. TDV is not biased in favor of natural gas and it does not "punish" electric space and water heating, it simply reflects their cost effectiveness relative to other options.

4. Why doesn't the Energy Commission focus on greenhouse gas emissions reductions instead of the TDV of energy cost effectiveness?

- The Warren-Alquist Act (the Act) established the Energy Commission in 1974 and governs the work of the Energy Commission. The Energy Commission has seven core responsibilities. One of those responsibilities is to promote energy efficiency and conservation. The Act requires the Energy Commission to adopt cost effective building energy efficiency standards. The cost effectiveness requirement of the Act has allowed the Energy Commission to be aggressive in developing energy efficiency standards for buildings while ensuring those regulations do not become fiscally burdensome to Californians.

5. Why does TDV use statewide average electricity and natural gas retail rate levels instead of actual retail rate structures that are in place?

    - The TDV uses statewide average retail rate levels for electricity, natural gas, and propane in order to keep similar stringency and common construction practices statewide (with some variations due to climate). The overall stringency of the code is set based on a project of future retail energy prices and using a statewide average result in uniform stringency of the standard.

6. Why is the Time Dependent variation set based on marginal costs?

    - By using the underlying system marginal costs, the TDVs reflect a "perfect" marginal cost of service. This means that the economic signal to save energy is aligned with the times that saving that energy is most valuable. We recognize that there are a number of different retail pricing structures in the state for electricity, natural gas, and propane that reflect underlying marginal costs to differing degrees. The approach of using a marginal cost basis reflects a long-term trend toward retail rates that reflect the marginal cost of service and keeps the building energy efficiency code relatively stable over time while also providing the greatest underlying value to the energy system.

7. Why are TDV units in kBTU/kWh and kBTU/therm if they measure cost effectiveness?

- TDV are calculated in life cycle dollars per unit of energy for each hour and climate zone in California. For the purposes of building code compliance, they are converted to units of kBTU/kWh and kBTU/therm using fixed multipliers. This is done because of a long-standing precedent of using 'source energy' factors in building code analysis, which is familiar with many practitioners. In addition, conversion to energy units prevents confusion between a long-term estimate of consumer bill savings based on a California average over 30 years and specific customer bill savings in a specific year and location.

8. Why doesn't the Energy Commission adjust TDV to reflect the cost effectiveness of technology "x" or this aspect of technology "y"?

    - The TDV metric are simply a reflection of price forecasts of energy in California and applicable across the range of most measures evaluated in the Building Energy Code. They should not be manipulated to address the unique issues regarding every possible technology. TDV savings is only one aspect of estimating the cost effectiveness of any Standards measure. Any unique aspects of a given technology should be considered when conducting a larger analysis of the technology as part of an effort to integrate that technology into the Standards.

2 Major Updates to 2019 TDV Methodology

This section summarizes the key changes to the 2022 TDV methodology compared to the 2019 approach. For other components of the electric, natural gas, and propane TDVs, the 2022 methodology represents minor updates and refinements to the 2019 methodology, as noted in Section 3, but does not include any major departures from the prior approach. In addition to major updates to TDV, the 2022 code cycle introduces an hourly source energy metric that will serve as a secondary performance metric in the Title 24 building standards.

2.1 Changes to TDV Methodology

2.1.1 WEATHER FILES

The CTZ22 weather year was developed by Whitebox Technologies and Bruce Wilcox for the 2022 Title 24 Building Codes update. The development of this weather year shares much of the same methodology as the typical meteorological year used in previous code cycles (CZ2010). For each month, the year whose weather is most “typical” for California is selected. This selection is done for the state as a whole, instead of by climate zone so that weather is consistent across climate zones. The defining difference between CTZ22 and the prior CZ2010 weather data is that the historical weather is sampled from more recent years to reflect impacts of climate change. For areas outside of California, historical weather data from the same month-years in CTZ22 are used to maintain simultaneous, consistent weather across the entire footprint of the Western Interconnection. For more details on these new weather files, can be found through the CEC building standards docket[2].

[2] See CEC “Presentation – Weather Data for 2022 Standards” on 2022 Building Energy Efficiency Standards web page: **https://efiling.energy.ca.gov/GetDocument.aspx?tn=230286&DocumentContentId=61829**

2.2 Weather-Specific Load, New Loads, and Generation Profiles

In previous TDV cycles, historical hourly system load profiles were matched to the typical weather year in order to ensure cohesion between hourly building simulation loads and the hourly state of the broader electric grid. For example, hotter days tend to have higher electric demand across the state, which results in higher marginal costs of serving electricity; it is important for a building simulation to experience this hot day at the same time as the wholesale electricity markets modeled in the production simulation model. In the 2022 TDV code cycle, this framework is being taken one step further to incorporate new load shapes and generation shapes that are also time and weather dependent.

2.2.1 BUILDING AND TRANSPORTATION ELECTRIFICATION LOAD PROFILES

The underlying statewide load profiles in the 2022 electricity TDV will account for the load impacts from increased levels of building electrification and transportation electrification. Building electrification will become an increasingly impactful end use load for the electric system, adding load in colder winter hours when renewable energy may not be available. Transportation electrification will add significant amounts of demand to the electric grid. Transportation electrification load shapes will be dependent on market maturity of personal light-duty EVs versus medium/heavy-duty, charging behavior, and access to varying levels of charging infrastructure. While there is still some uncertainty in how these electrified loads will impact future markets, it is important to begin planning for these changes, and therefore are appropriate to include in the market forecasts that drive the TDV analysis. Both of these new load profiles are based on rapidly evolving technology; electrification load profiles should be revisited in future code cycles as new data and research become available. A more detailed description of the methodology behind these load profiles are available in Appendix C and Appendix D.

Figure 1. 2050 aggregated statewide building electrification load profile (profile of average day by month) used for production simulation modeling in 2022 TDV analysis

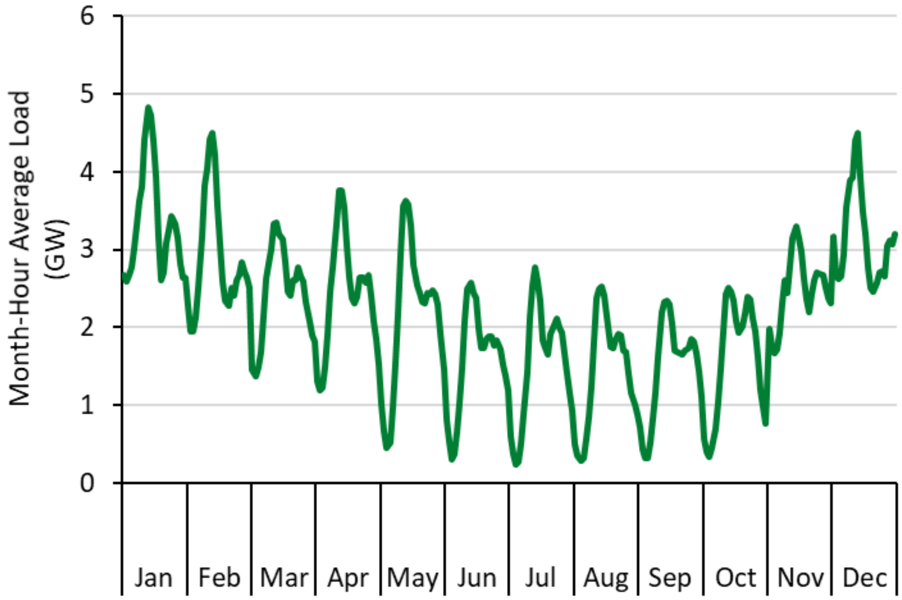
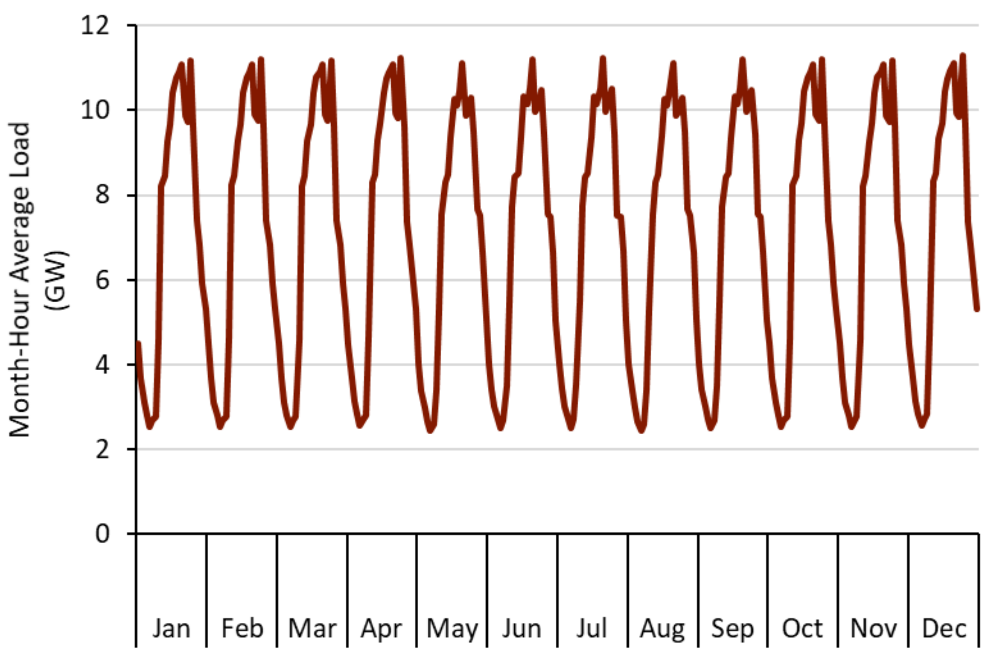


Figure 2. 2050 aggregated statewide transportation electrification loads (average day by month) used in production simulation modeling in 2022 TDV analysis

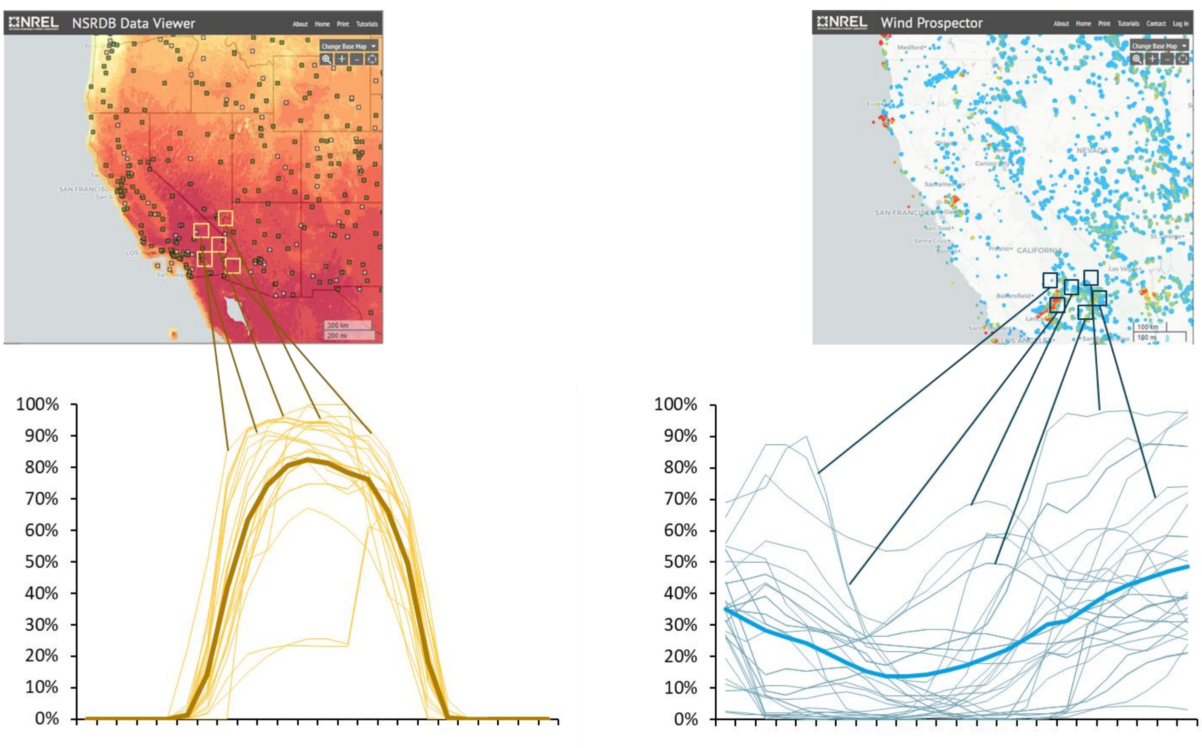


2.2.2 RENEWABLE PROFILES

Also new in the 2022 TDV code cycle, renewable generation shapes were created using data from the specific historical months that were used to generate the CTZ weather data. This approach for all renewable generation ensures the capture of both the correlation between renewable generation shapes and electric demand on the grid, as well as correlated renewable generation availability between different regions. This is an important nuance to capture and becomes even more important as the penetration of renewable generation on the grid increases.

For each defined wind or solar resource in WECC in the CEC's PLEXOS production simulation model, location-specific historical generation data and resource availability data from NREL's Wind and Solar databases were aggregated to create a representative weather-matched generation profile. This data aggregation was performed for all utility scale wind and solar, as well as behind-the-meter PV. A more detailed description of the data collection and aggregation methodology is available in Appendix E.

Figure 3. Renewable generation profile creation for 2022 TDV Production Simulation Modeling



2.3 Carbon Emissions Components

Compared to previous code cycles, the 2022 TDV code cycle adds new internalized cost streams to account for carbon emissions. In the 2022 TDV metric, there are three cost emissions-related cost streams:

- **Cap and Trade Emissions**: This is the direct cost of carbon emissions through California's cap and trade market ("Emissions" field in previous TDV code cycles). These costs are fully internalized in energy market prices, either through electricity or natural gas bills. Since Cap and Trade is an economy-wide market, it is applicable to electricity, natural gas, and propane TDVs.
- **Supply-side GHG Adder** (Electricity TDV Only): This field replaces the previous RPS Adder. Like the RPS Adder, the GHG Adder represents the changes in procurement of renewable generation based on changes in electric load. The GHG Adder field is based on the costs associated with meeting annual electricity sector emissions limits through supply side renewable procurement. Following the investment represented in the GHG Adder, incremental renewables are brought online with new load, thus offsetting the emissions impact of increased loads; this is the basis of long run marginal source energy or long run marginal emissions. The supply-side GHG Adder only applies to electricity TDVs.
- **Economy-wide emissions abatement**: This field represents the economy wide emissions abatement cost above and beyond the Cap and Trade market and cost of meeting electricity sector renewable generation targets. In a future where the Cap and Trade price ceiling is insufficient to achieve statewide emissions targets, there will be an economy-wide emissions abatement cost above and beyond those market prices. If these reductions don't come from one sector of the economy, they must come from another sector, and regardless of the specific market mechanism (RPS, low carbon fuel standard, other emissions reductions incentives, etc), there will be a cost incurred by the state. Economy-wide emissions abatement only covers the emissions and abatement costs that are not covered by other TDV fields. This field applies electricity, natural gas, and propane TDVs, and is valued at the economy-wide marginal cost of emissions abatement.

In addition to these new cost streams, the 2022 TDV metrics will incorporate non-combustion, CO_2-equivalent emissions from methane leakage and refrigerant leakage into the economy-wide abatement costs.

2.4 Shaped Retail Rate Adjustment

New to TDV in the 2022 code cycle, the retail rate adjustment is now partially scaled to hourly marginal cost of service. Previously, the difference between utility rate projections and annual average avoided costs were allocated evenly across all hours of the year. However, with recent advances in dispatchable distributed energy resources, such as energy storage and flexible loads, future retail rates will need to consider sending a retail rate signal that incentivizes the optimal behavior of these new technologies. Indeed, SMUD and the IOUs have moved or are moving to energy rates for all customers that vary by time-of-use period. To account for such rate signals, 15% of the retail rate adjustment is scaled based on hourly marginal cost of service. This allows for a strong dispatch signal for dispatchable technologies, without compromising a consistent price signal for energy efficient building design measures.

2.5 Non-Combustion Emissions

As the focus on climate impacts and greenhouse gas emissions grows ever more important in long-term infrastructure planning, the 2022 TDV code cycle incorporates two significant sources of greenhouse gas emissions present in buildings – methane leakage and refrigerant leakage. These emissions are factored into the economy-wide emissions abatement cost component TDV for the relevant fields.

Methane leakage upstream of end use consumption is a recent focus area of scientific research. Methane has a much higher GWP than carbon dioxide, and therefore has a much higher climate impact for each emitted unit. There is still some uncertainty of where leaks happen along the natural gas supply chain, and if those leaks are marginal based on changes in system throughput, or changes in new construction end use source fuel choices. The 2022 TDV analysis takes a conservative approach to answering this question for this code cycle; leakage rates should be reconsidered and updated as better scientific research becomes available. This code cycle represents an important first step in acknowledging methane leakage as a source of greenhouse gas emissions that should be internalized in lifecycle cost considerations.

While refrigerants are not necessarily leaked in large quantities relative to economy carbon dioxide, the global warming potential (GWP) of commonly used refrigerants is often several orders of magnitude greater than CO_2[3]. In many refrigerant applications, loose fittings or mishandling of refrigerants at end of life cause much of the refrigerant to be leaked into the atmosphere. Some low-GWP refrigerants exist, though still may not be adopted widely due to trade-offs of flammability, toxicity, or technological readiness. It is important to acknowledge the trade-off of greenhouse gas emissions for refrigerants in the context of new building standards and provide a signal to encourage the development and adoption of new low-GWP refrigerants.

2.6 New Source Energy Metric

The 2022 TDV code cycle includes, for the first time, a second hourly metric – long run marginal source energy. The source energy metric does not replace TDV; it is intended to be a secondary performance metric, giving a complementary evaluation of building design decisions. While TDV represents a participant cost test, the source energy metric is a proxy for environmental benefit.

Long run marginal source energy, in this application, is defined as the source energy of fossil fuels following the long-term effects of any associated changes in resource procurement. This new metric focuses specifically on the amount of fossil fuels that are combusted in association with demand side energy consumption. Including this as a metric provides a new pathway for state regulators to align building codes and standards with the state's environmental goals.

[3] The refrigerant R-410A, for example is used in most residential air conditioning units and heat pumps and has a GWP of 2088

3 2022 TDV Inputs

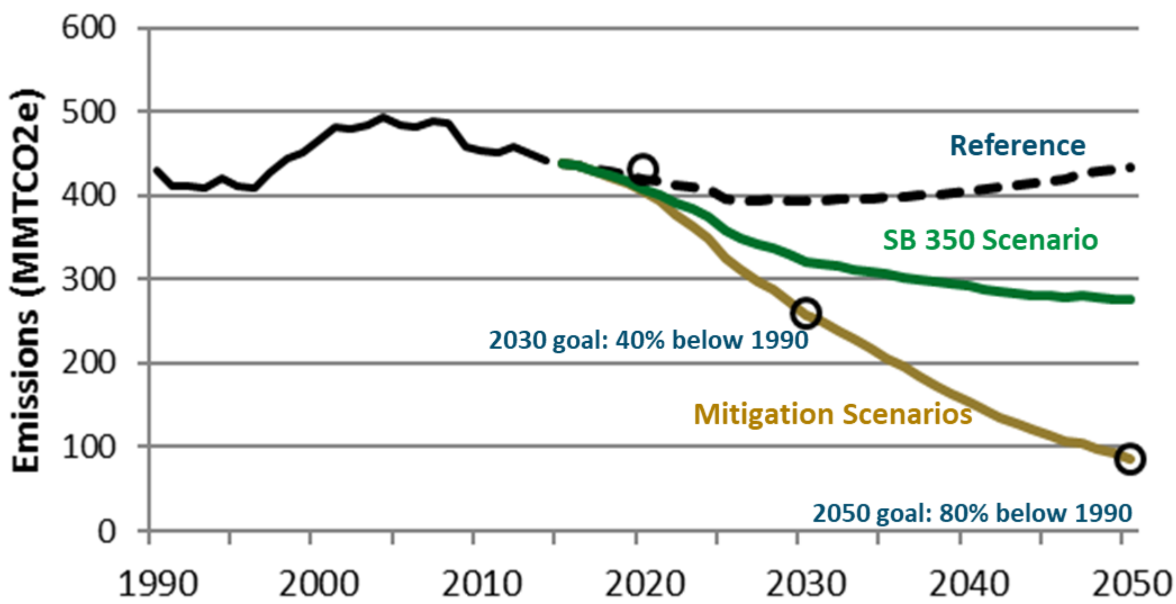
In this section we will walk through each component of the 2022 TDVs and document associated updated inputs for electricity, natural gas, and propane.

3.1 Overview of Scenario Assumptions

This section describes the over-arching scenario assumptions that apply to all TDV categories, as well as the source energy metric.

In prior analyses in 2013, 2016 and 2019, the majority of the input assumptions were taken from the latest Integrated Energy Policy Report (IEPR) and associated planning documents. In 2019, this approach was updated to include consideration for Senate Bill 350's (SB350) policy targets of 50% Renewable Portfolio Standard (RPS) by 2030 and a doubling of energy efficiency by 2050. For 2022 TDVs, input assumptions are updated once again to reflect the latest energy policies. For electric TDVs, this includes updated end use loads that reflect a future scenario with 80 x 50 emissions targets (80% below 1990 levels by 2050), as well as updated supply side resources that meet SB100 goals of 100% RPS by 2045. For natural gas TDVs, these policy effects are also reflected in end use loads and a forecasted retail gas fuel blend. Figure 4 shows the magnitude of California's goals of 80% emissions reductions below 1990 levels.

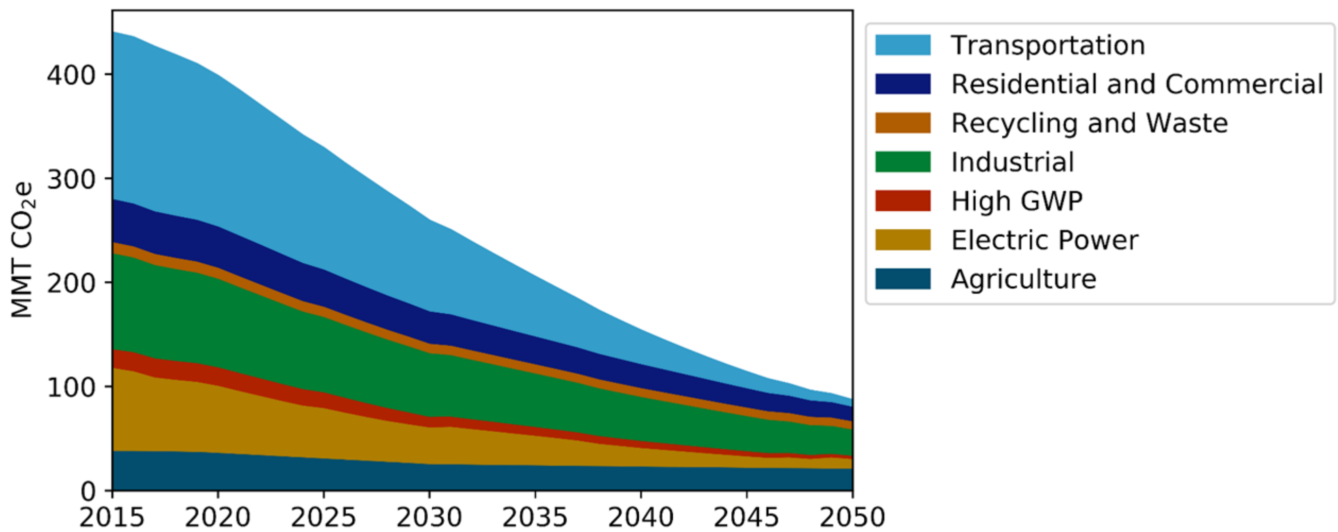
Figure 4. California Historical GHG Emissions and GHG Scenarios



To represent an 80x50 compliant future scenario, E3 used a PATHWAYS scenario that was recently developed for a CEC-funded study on Natural Gas Distribution in California's Low Carbon Future. PATHWAYS[4] is E3's proprietary stock rollover model that calculates sub sector level emissions reductions required to meet economy wide emissions targets. PATHWAYS has been used by California regulators and policy makers to evaluate the costs and implications of employing different approaches to achieve its economy wide emissions targets. Figure 5 shows the sector-level emissions from the selected PATHWAYS scenario. Significant emissions reductions are necessary in all sectors, especially transportation, buildings, and electric power.

[4] Deep Decarbonization in a High Renewables Future, 2018. https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

Figure 5. Annual emissions by economy sector from the PATHWAYS scenario[5] used in 2022 TDV



To achieve a given set of economy-wide emissions targets, there are numerous technological pathways, all with different costs and implications, as explored in the Natural Gas Distribution in California's Low-Carbon Future report[6]. If one sector of the economy is given a relatively higher annual emissions budget, deeper emissions reductions must come from a different sector. Given the magnitude of economy-wide emissions reductions, this places a larger burden on sectors that have more technologically feasible decarbonization solutions, such as electric power generation, building electrification, or light duty vehicle electrification. Significant changes in fuel type and consumption for a given sector, such as transportation electrification or building electrification, will have significant impacts on existing infrastructure, both in terms of increased usage (needing new infrastructure to accommodate new loads), or decreased usage (potentially stranding assets in existing infrastructure).

The selected PATHWAYS scenario sets several inputs assumptions used in this analysis. First, it determines electricity and natural gas end use consumption for each year, incorporating the effects of increased energy efficiency, as well electrification. Second, it determines the allowable emissions from

[5] This analysis used the Multi-Prong with Slower Building Electrification Scenario from the PATHWAYS modeling performed in the Natural Gas Distribution in California's Low-Carbon Future study

[6] Draft Report: Natural Gas Distribution in California's Low-Carbon Future, 2019. **https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-D.pdf**

the electricity sector to serve the electric load, while meeting economy wide emissions reductions goals. Electricity sector emissions limits guide the magnitude and costs of renewable generation procurement, which in turn effects the marginal costs to operate the electricity system. Lastly, it determines the allowable emissions intensity of retail natural gas, as set by an assumed fuel blend of natural gas, biogas and hydrogen.

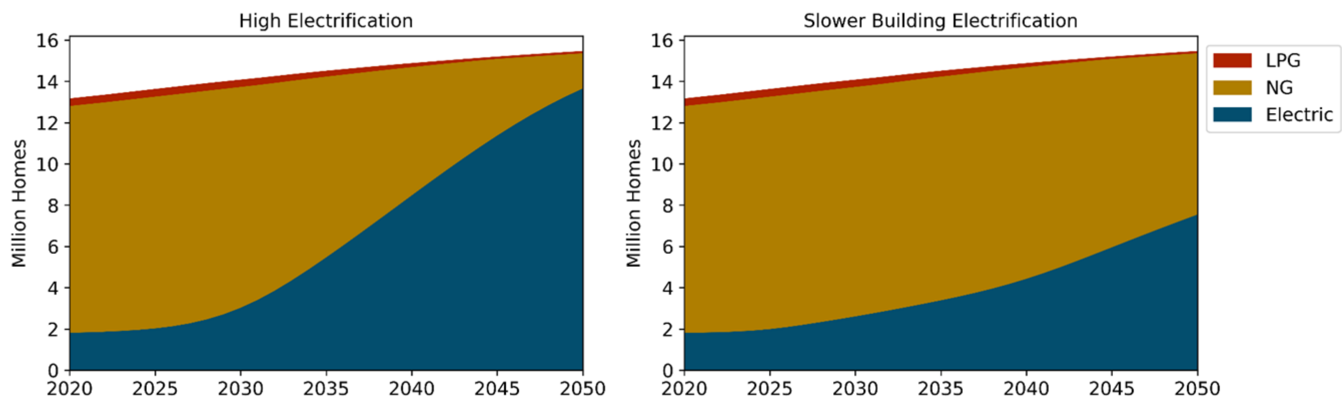
As the TDV analysis and metrics have a direct impact on the energy consumption and fuel choices in California's buildings, there is potential for a feedback loop in cost benefit analyses if the over-arching PATHWAYS scenario already assumes significant building electrification. Significant building electrification would decrease throughput through the gas distribution system; that scenario assumption would spread the fixed costs of the natural gas distribution system across a smaller amount of volumetric consumption, thus causing retail gas rates to increase. A scenario reflecting these much higher retail rates would show building electrification as more cost effective in building standards, only on the merit that the scenario assumed higher levels of building electrification. To avoid this feedback loop, the "Slower Building Electrification" PATHWAYS scenario was selected as the over-arching assumption for this analysis.

Compared to other statewide PATHWAYS scenarios, the "Slower Building Electrification" PATHWAYS scenario is, overall, a more expensive pathway for the state achieving its 80x50 targets, but it prevents the aforementioned feedback loop by assuming deeper decarbonization measures in other sectors and setting a higher carbon budget for retail gas consumption. This creates a scenario with lower forecasted natural gas retail rates than other PATHWAYS scenarios[7]. The Slower Building Electrification scenario has a moderate amount of building electrification that does not decrease natural gas consumption to the point of stranding natural gas distribution infrastructure. It also includes contains a limited amount of renewable natural gas to reduce the carbon intensity of retail gas. While this scenario in PATHWAYS yields an overall higher statewide cost of emissions abatement, it creates a robust counterfactual baseline for any potential cost benefit analyses for building electrification in the context of building standards.

[7] It is noted that the rate forecasts are all generally higher than CEC IEPR forecasts which were used in previous TDV cycles. Draft Report: Natural Gas Distribution in California's Low-Carbon Future, 2019. **https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-D.pdf**

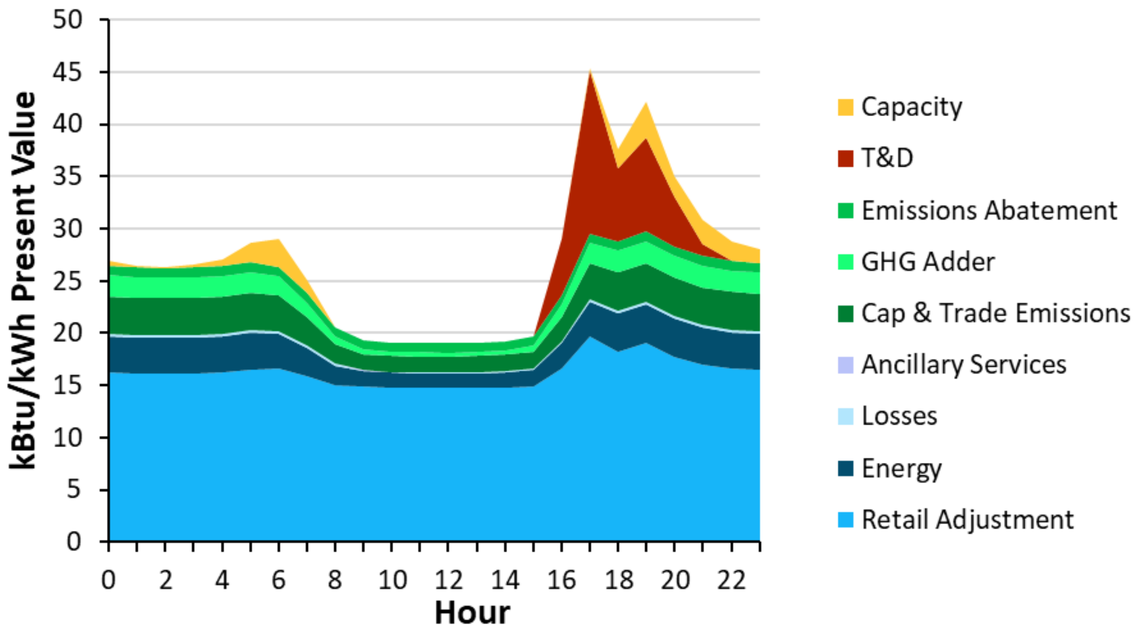
In the Slower Building Electrification scenario, approximately 18% of homes are electrified by 2030 and 49% are electrified by 2050. Figure 6 shows a comparison of building electrification between the Slower Building Electrification scenario, and the High Electrification PATHWAYS scenario; the High Electrification scenario is among the least costly PATHWAYS scenarios for California to achieve 80x50 emissions reductions goals, and is a high bookend for building electrification by 2030 among PATHWAYS scenarios. higher bookend case. In the Slower Building Electrification scenario, increased emissions in the building sector are offset by deeper emissions reductions in other sectors.

Figure 6. Comparison of primary space heating fuel type in homes, between two PATHWAYS scenarios.



3.2 Electricity 2022 TDV Inputs

Figure 7. Sample TDV shape by component, Average day, levelized 30-year residential, CZ12



3.2.1 OVERVIEW OF AVOIDED COSTS OF ELECTRICITY

For each climate zone, the avoided cost of electricity is the sum of nine components, each of which is summarized in Table 1.

Table 1. Components of Time Dependent Valuation for Electricity

	Component	Description
Marginal Energy Avoided Costs	Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
	System Capacity	The marginal cost of procuring Resource Adequacy resources in the near term. In the longer term, the additional payments (above energy and ancillary service market revenues) that a generation owner would require to build new generation capacity to meet system peak loads
	Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability
	System Losses	The costs associated with additional electricity generation to cover system losses
	T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads
	Cap & Trade Emissions	The direct cost of carbon dioxide emissions (CO2) associated with the marginal generation resource
	GHG Adder	The costs of procuring additional renewable resources to offset emissions from increased loads, in order to meet electricity sector emissions intensity targets. Analogous to the previous RPS Adder
	Emissions Abatement	The costs of abating residual emissions beyond electricity sector emissions intensity targets. Analogous to previous Carbon Externality. Emissions abatement is not included in retail rate forecasts and therefore added incrementally to total TDV.
Retail Rate Adder		Above components (excluding Emissions Abatement) are scaled to match the average retail rate through the retail rate adder.

Each component is estimated for each hour and forecasted into the future for 30 years. The hourly granularity of the avoided costs is obtained from several sources. The wholesale price of electricity shape is obtained from production simulation dispatch model runs. Other components of the value calculation are derived by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices reported by the California Independent System Operator (CAISO's MRTU system). Table 2 summarizes the methodology applied to each component to develop the hourly price shapes.

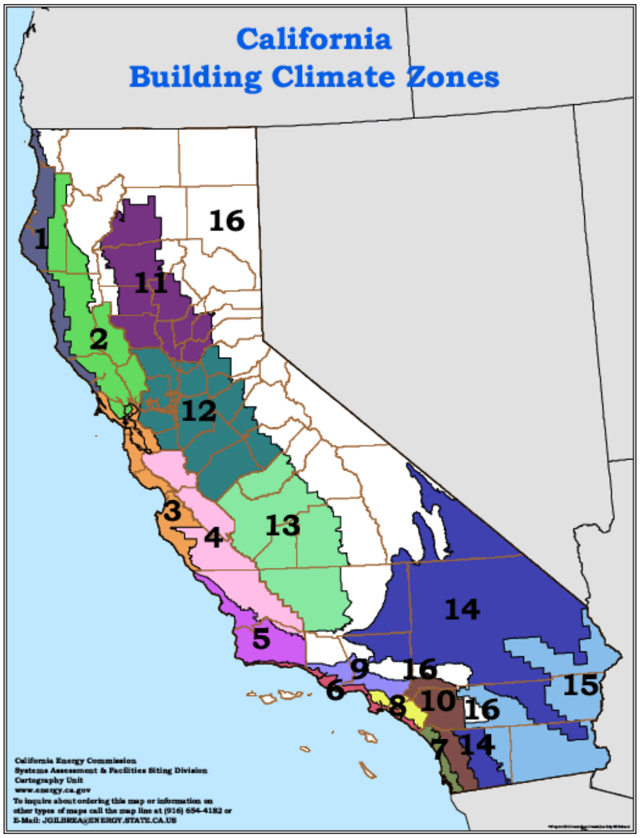
Table 2. Summary of methodology for electric TDV component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	IEPR Production Simulation Results for 2023-2030 and 2045, escalated based on gas price forecasts.	IEPR Production Simulation Results
System Capacity	Fixed costs of a new simple-cycle combustion turbine, less net revenue from energy and AS markets. Long-term set by the fixed O&M of	Effective Load Carrying Capacity

	operating a Combined Cycle Gas Turbine	
Ancillary Services	Scales with the value of energy	Hourly energy avoided costs
T&D Capacity	Survey of investor owned utility transmission and distribution marginal costs from recent general rate cases	Hourly allocation factors calculated from a regression that includes hourly temperature data and distribution feeder load data
Cap and Trade Emissions	2019 IEPR Cap and Trade price forecasts	Implied heat rate of marginal generation based on hourly avoided energy costs
GHG Adder	Premium for reducing emissions with supply side procurement, calculated from an SB100 compliant scenario in RESOVLE	Implied heat rate of marginal generation based on hourly avoided energy costs. Uses the difference between marginal heat rate and annual emissions intensity target
Economy-wide Emissions Abatement	Cost of economy-wide marginal emissions reductions, beyond Cap & Trade	Constant allocation factor, does not vary by hour.
Retail Rates	2019 IEPR Mid-Demand Scenario	Constant allocation factor, does not vary by hour

In each hour, the value of electricity delivered to the grid depends on the point of delivery. The Title 24 Standard uses sixteen California climate zones in order to differentiate the changing value of electricity across different regions in California. These climate zones group together areas with similar climates, temperature profiles, and energy use patterns in order to differentiate regions in a manner that captures the effects of weather on energy use. Figure 8 is a map of the Title 24 climate zones in California.

Figure 8. California Climate Zones used in Building Code Standards



Each climate zone has a single representative city, which is specified by the California Energy Commission. These cities are listed in Table 3, along with the IOU service territory that serves the majority of the load in each climate zone.

Table 3. Representative Cities for California Climate Zones

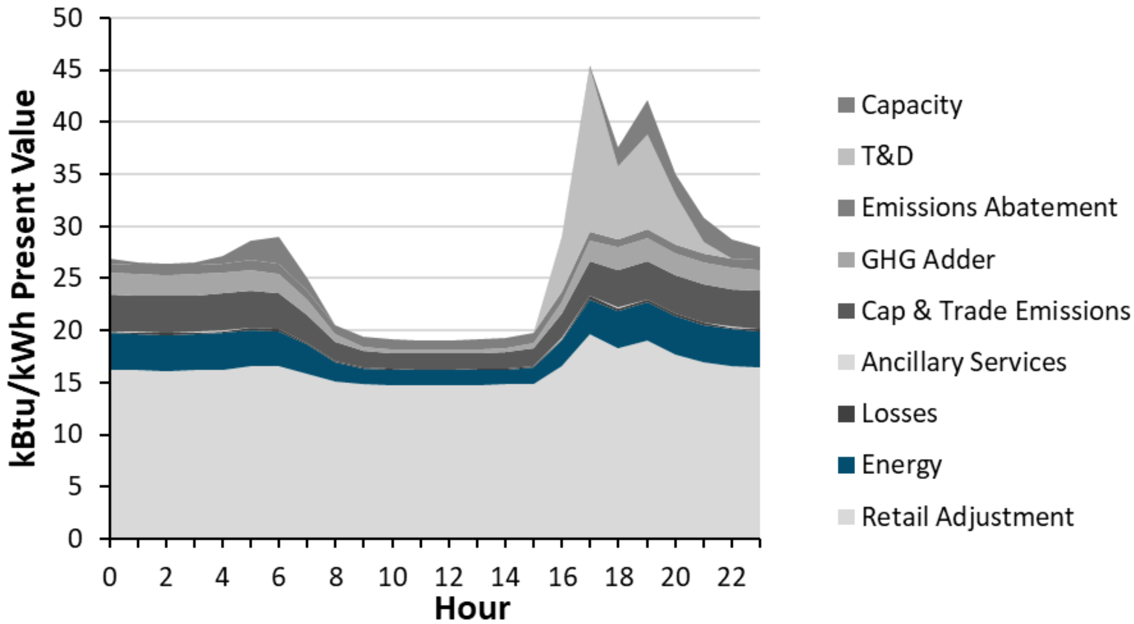
Climate Zone	Representative City	Majority IOU Territory
CEC Zone 1	Arcata	PG&E
CEC Zone 2	Santa Rosa	PG&E
CEC Zone 3	Oakland	PG&E
CEC Zone 4	Sunnyvale	PG&E
CEC Zone 5	Santa Maria	SCE
CEC Zone 6	Los Angeles	SCE
CEC Zone 7	San Diego	SDG&E

CEC Zone 8	El Toro	SCE
CEC Zone 9	Pasadena	SCE
CEC Zone 10	Riverside	SCE
CEC Zone 11	Red Bluff	PG&E
CEC Zone 12	Sacramento	PG&E
CEC Zone 13	Fresno	PG&E
CEC Zone 14	China Lake	SCE
CEC Zone 15	El Centro	SCE
CEC Zone 16	Mount Shasta	PG&E

Most of the components of avoided costs in the 2022 TDVs do not vary by IOU service providers. The two exceptions are avoided line losses and the market price shapes developed in the CEC's production simulation dispatch model, which vary based on the IOU service providers specified in Table 3. All other components of the avoided cost of electricity are calculated using statewide average utility costs, including residential and nonresidential retail rates and avoided transmission and distribution costs. This is consistent with the 2019 TDV methodology.

E3 uses a unified statewide average retail rate forecast for TDV to provide a consistent evaluation framework for calculating lifecycle costs; over a 15 or 30-year analysis period, current differences between IOU costs may change. From a policy perspective, it is not desirable to have significantly different incentives being offered in neighboring climate zones due to differences in IOU utility costs, as was the case using the 2013 TDVs. By using statewide average costs in the 2016, 2019, and 2022 TDVs, the large differences between the climate zones seen in 2013 have been reduced.

3.2.2 AVOIDED COSTS OF ENERGY



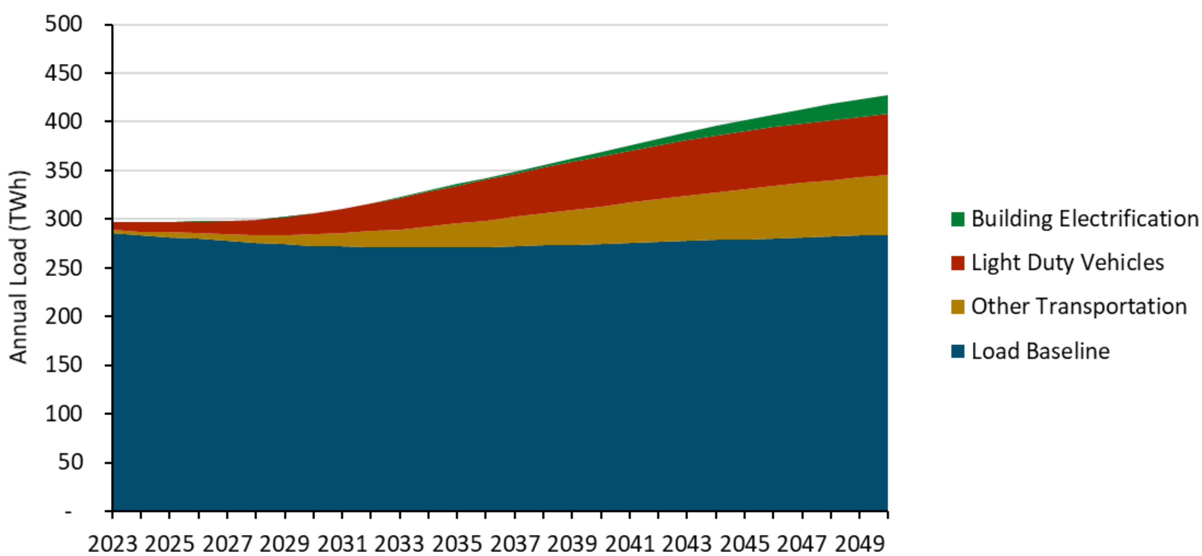
The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. The CEC performs extensive production simulation modeling as a part of the IEPR update process. As with the 2019 TDVs, the production simulation cases are re-run with load shapes that are correlated to the TMY weather files. New in the 2022 code cycle, renewable generation shapes are also correlated to the TMY weather files, add the existing resource portfolio in PLEXOS was supplemented with additional renewable generation resources that are consistent with statewide renewable capacity expansion modeling. For the 2022 TDV Update, the PLEXOS production simulation model creates results from 2023-2030, with an additional out-case in 2045.

To remain consistent with the over-arching economy-wide emissions scenario, along with specific renewable energy targets, E3 determined an optimal policy compliant generation portfolio, using RESOLVE. RESOLVE is E3's proprietary capacity expansion model that is currently being used to define reference system plans for load serving entities in the CPUC's 2019-2020 Integrated Resources Planning proceeding[8]. The RESOLVE model used in this analysis is based on the version used in the electricity

[8] CPUC IRP https://www.cpuc.ca.gov/irp/

sector analysis for the CEC's Deep Decarbonization in a High Renewables Future study[9]. Load forecast inputs were updated using data from the PATHWAYS analysis in the CEC's Natural Gas Distribution in California's Low-Carbon Future study[10]. Figure 9 below shows the annual demand forecast by component used in the model. Additionally, load profiles were updated using data from the process described in 2.2. Finally, cost inputs were updated using data derived from NREL's 2018 Annual Technology Baseline[11] and Lazard's Levelized Cost of Storage Version 4.0[12]. Figure 10 below shows the technology cost assumptions used.

Figure 9. Annual demand forecast by component for electricity TDV capacity expansion modeling



[9] Deep Decarbonization in a High Renewables Future – Updated Results from the California PATHWAYS Model. June 2018. https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf

[10] Appendix of the Draft Results: Future of Natural Gas Distribution in California - CEC Staff Workshop for CEC PIER-16-011. June 2019. https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdfv

[11] NREL 2018 ATB. July 2018. https://atb.nrel.gov/electricity/2018/v

[12] Lazard Levelized Cost of Storage Version 4.0. November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

Figure 10. Average technology costs for new candidate resources.

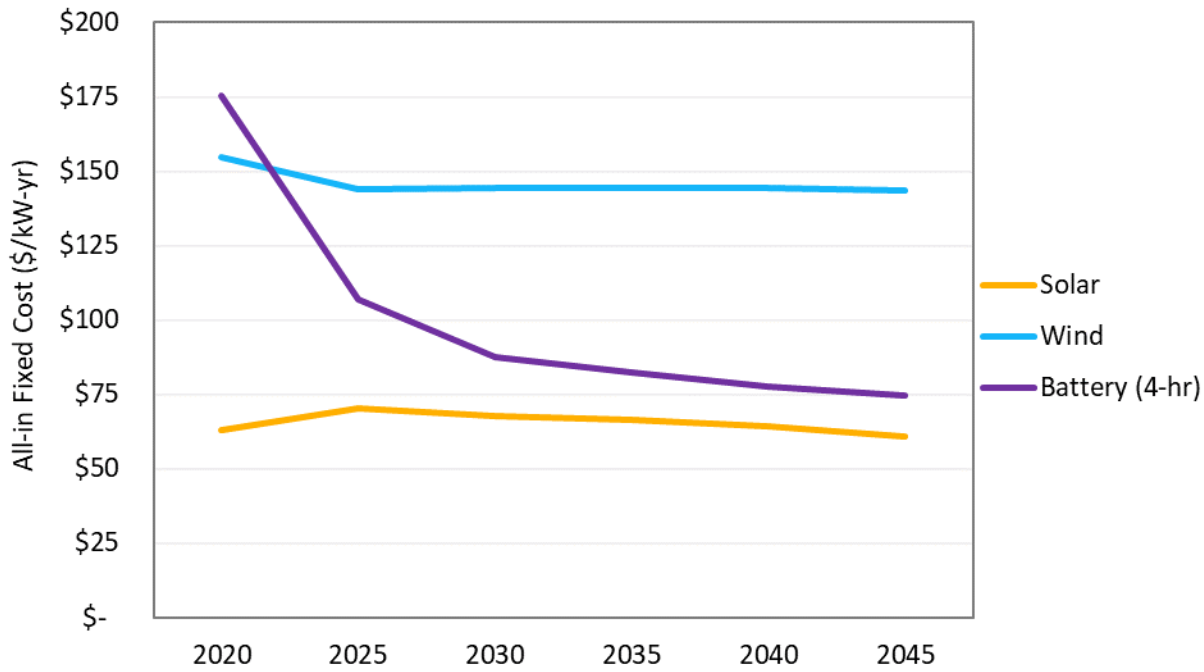


Figure 11 and Figure 12 below show the total state generation portfolio required to meet the major policy targets included in this analysis, and corresponding annual generation. Before 2020, the capacity additions are solely based on economic value. By 2030, in addition to economic value, the GHG emissions targets also drive the need for zero-carbon generation. As a result, even more renewable resources and storage are added. As the GHG emissions constraints become more stringent beyond 2030, a greater amount of storage is needed to balance the additional solar resource.

Figure 11. Forecasted generation portfolio from RESOLVE to meet the capacity and policy requirements included in this analysis

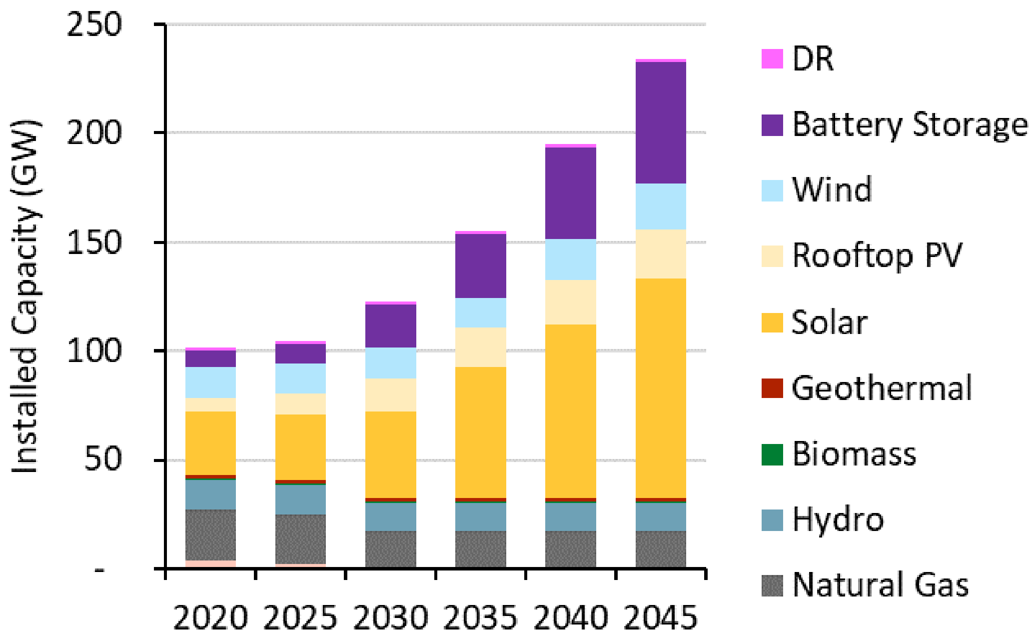
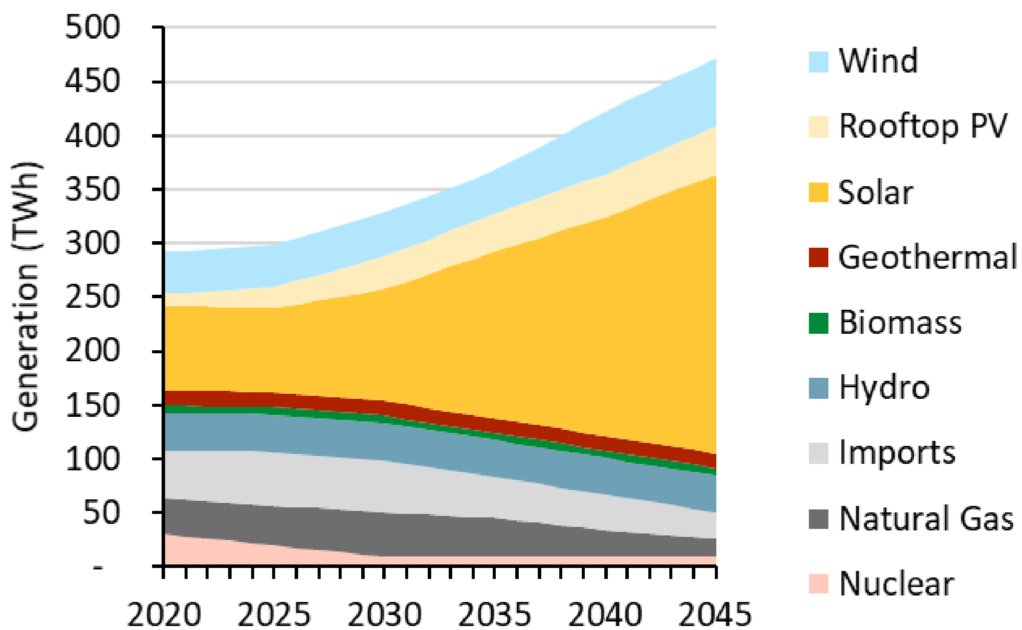


Figure 12 RESOLVE annual generation by resource



RESOLVE capacity additions, along with weather-correlated renewable generation profiles, described in Appendix E were added to the CEC's IEPR PLEXOS model.

Consistent with the approach used in previous TDV cycles, the production simulation cases are run using load shapes consistent with the statewide typical meteorological year files (based on the CTZ22 weather year) for a 2009 calendar year. This allows the production simulation to model the correlation between prices and weather and means that the hottest days of the year in the CTZ22 files will also correspond to the highest TDV value hours of the year. Appendix B describes the process of translating historical load into the new weather year.

In addition to historical loads, hourly load forecasts included approximated hourly load shapes for transportation electrification and building electrification, as described in Appendix C and Appendix D.

With these 2022 TDV inputs in place, PLEXOS generates 8,760 hourly wholesale electricity price forecasts for 2023-2030, as well as 2045. Years between 2030 and 2045 are linearly interpolated and beyond 2045, electricity prices are escalated with the annual increase, based on the compound annual growth rate from the 2019 preliminary IEPR natural gas price forecast, which is discussed in more detail in Section 3.3.3. These results are converted to marginal heat rates in order to interact with price inputs sensitivities unique to the TDV spreadsheet model. The resulting average energy price is shown in Figure 13. The energy price shape from 2045 is used for all remaining years.

Figure 13. Average wholesale energy price without the cost of emissions

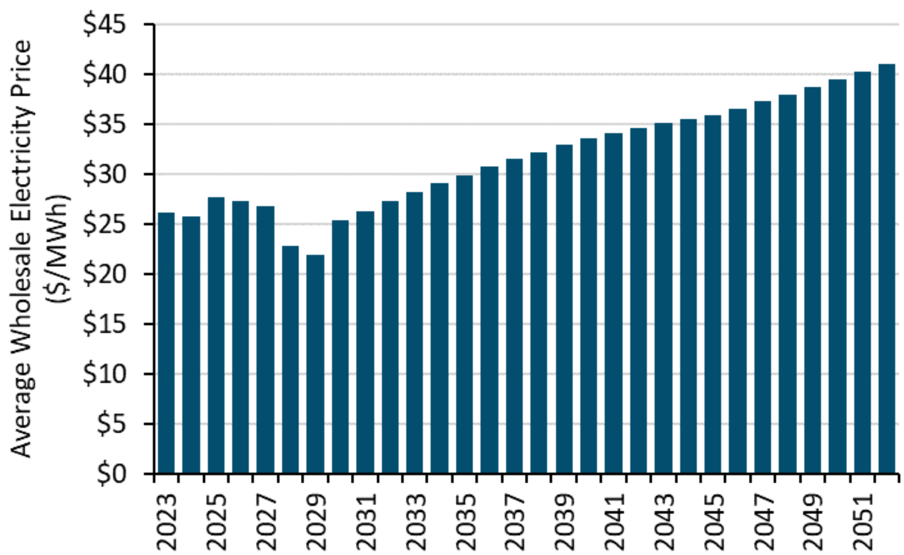


Figure 14 below shows the lifetime NPV hourly price shapes that result from the production simulation modeling, comparing the 2022 TDV avoided costs of energy with the 2019 TDV avoided costs of energy. The heavier emphasis on renewable generation in the 2022 TDVs creates a much lower wholesale electricity price in mid-day, when solar generation is at its peak. This trend is reflective of current wholesale market prices in times of significant solar generation.

Figure 14. Wholesale Energy Price Shapes compared from 2019 and 2022 TDVs

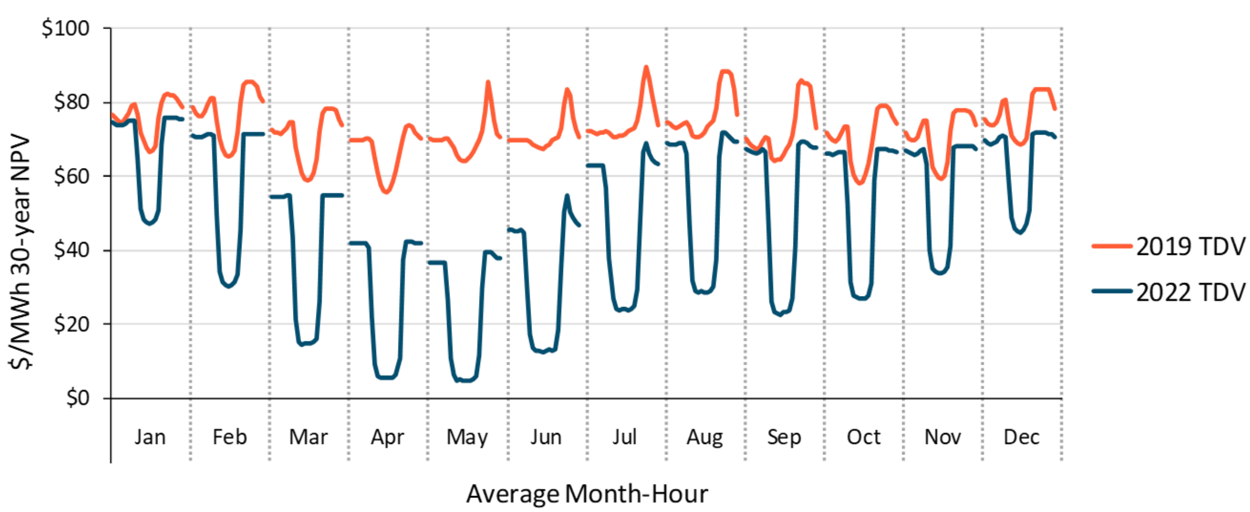
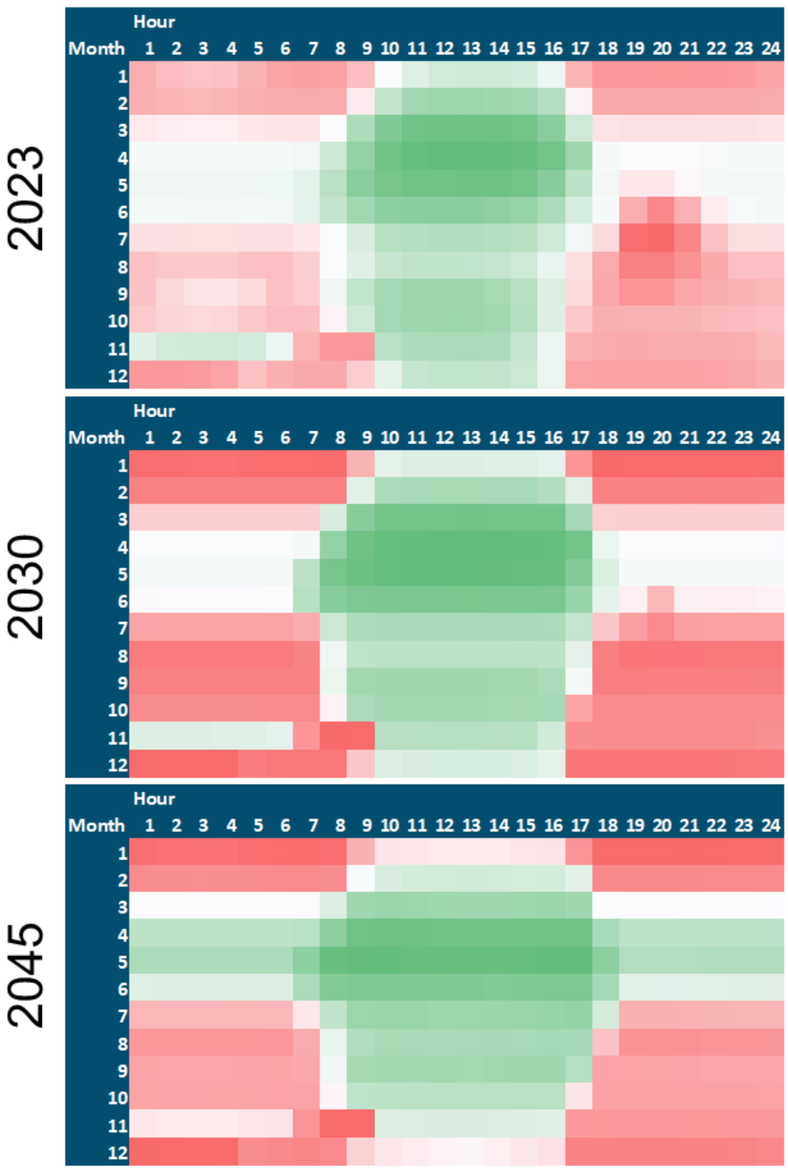
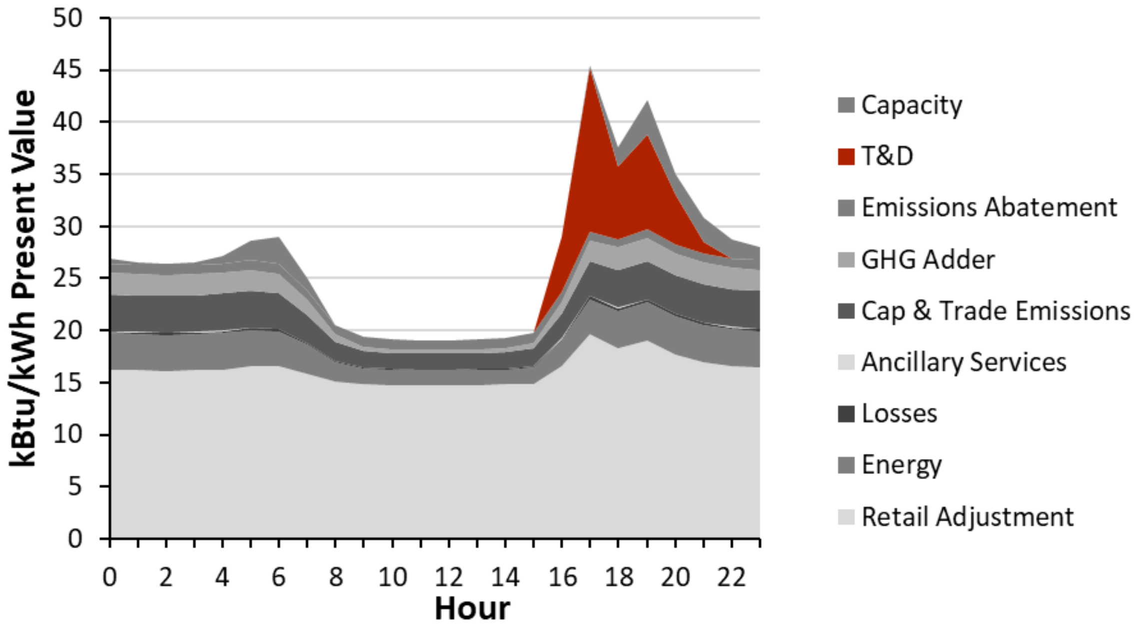


Figure 15 shows the hourly price shape trend between simulated years. Not only is there a trend of suppressed mid-day prices across all years, but notably, there is a decreasing summer evening peak in later years. This is due to increased penetration of renewable generation and energy storage. Energy storage is able to charge with excess solar most days, and discharge in the evening to flatten evening and nighttime prices. By 2045, peak prices move to winter mornings, during periods of low solar availability, when there is not enough daily energy on the system to charge batteries for a full night.

Figure 15 2022 TDV month-hour average marginal electricity price shapes for 2023, 2030, and 2045



3.2.3 TRANSMISSION AND DISTRIBUTION CAPACITY AVOIDED COSTS



Transmission and distribution avoided costs are calculated using the weighted average from the latest utility general rate cases (GRCs). For the 2022 cycle, we have updated these costs to reflect the most recently available data at the time of this analysis from the PG&E 2017 GRC, SCE 2018 GRC, and SDG&E 2016 GRC.[13] This is the same data used in the recent 2019 CPUC Avoided Cost Calculator update. The results are shown in Table 4.

[13] PGE: October 26, 2017 Settlement Agreement, A.16-06-013 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M202/K235/202235606.PDF
SCE: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F40D6AEFD8622526882581CB007FC097/$FILE/A1706030-%20SCE-02A-2018%20GRC%20Ph2-Various-Errata%20Marginal%20Cost%20and%20Sales%20Forecast.pdf
SDG&E: A.15-04-012 D.17-08-030 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M194/K599/194599448.PDF

Table 4. Weighted average of avoided T&D Costs for 2022 TDVs

	Statewide Avoided Costs [$/kW-yr]
Transmission	$24.47
Distribution	$102.54

These avoided costs are allocated to hours and climate zones using the same methodology that was used in the 2019 TDV code cycle; this relies on actual utility distribution loads and behind-the-meter PV forecasts. The new CTZ22 weather year was applied to this methodology to determine T&D Capacity Allocation.

The allocation of T&D capacity costs to hours of year is based on regression estimates of distribution hourly loads. The regression models are based on actual utility hourly distribution demands and the corresponding temperature in the distribution area. Using dummy variables, lag terms, and cross product terms, the regression models are able to simulate the distribution loads with about 90% accuracy (adjusted r-square). To forecast the impact of local solar PV on the distribution loads, the analysis also subtracts off a forecast level of hourly PV generation from the distribution load to produce an adjusted distribution load shape. The PV generation shape is based on the local area solar insolation, and the magnitude of the PV generation is based on the statewide forecast of solar penetration of the selected PATHWAYS case. This incremental PV forecast is allocated across the climate zones based on the geographic distribution of California Solar Initiative installations and forecasted annual load.

Once the adjusted distribution loads are simulated using CTZ22 weather data for each climate zone, and the PV penetrations, we allocate the T&D capacity value in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load. The allocation factors are derived using the peak capacity allocation factors method, with the additional constraint that the peak period contain between 20 and 250 hours for the year.

PCAF[a,h] = (Load[a,h] – Threshold[a]) / Sum of all positive (Load[a,h] – Threshold[a])

Where

- a is the climate zone area,
- h is hour of the year,
- Load is the net distribution load, and
- Threshold is the area maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 20 and 250 hours with loads above the threshold.

Figure 16 shows a summary of the updated T&D allocation factors for Climate Zone 12 (Sacramento) in 2023. The blue line shows the total allocation weight for each hour of the day (in Pacific Standard Time) and the gray bars show the total allocation weight by month (top axis, and right axis). The chart title also indicates that the allocation factors are based on behind-the-meter PV providing an additional 11.5% of the electricity needs in the climate zone since 2010. The PV values are incremental to 2010 because that is the year of the utility load data used as the basis for the simulated area loads. The additional PV output is subtracted from the simulated loads to estimate the adjusted net loads for the climate zone.

Figure 16. Updated T&D Allocation Factors for CZ12 in 2023

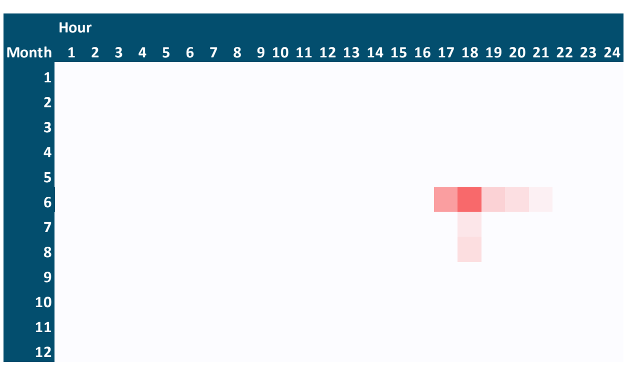


Figure 17 shows the same information for Climate Zone 12 in 2033. In 2033 the behind-the-meter PV is modeled as providing 22.5% of the electricity needs in the climate zone. This higher PV output results in less need for summer afternoon peak capacity. This shifts the allocation factors to later in the day/evening, as well as shifting more weight to the non-summer months.

Figure 17. Updated T&D Allocation Factors for CZ12 in 2033

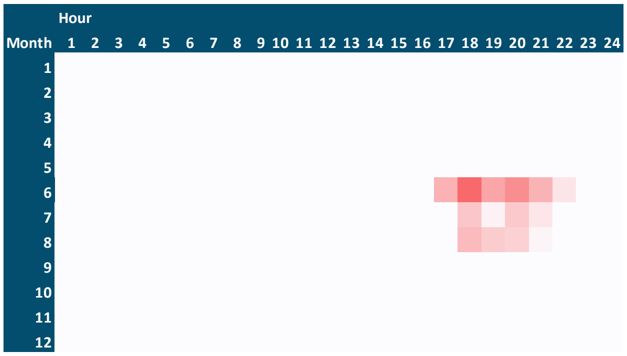
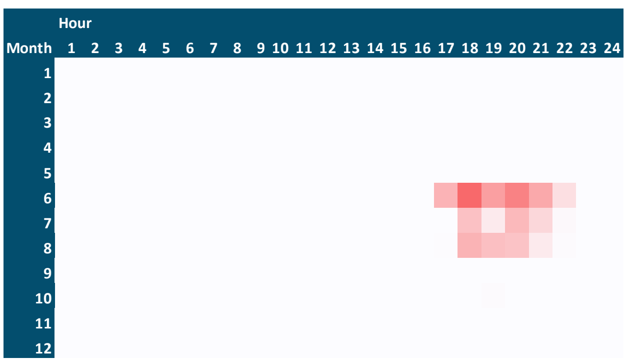


Figure 18. Updated T&D Allocation Factors for CZ12 in 2045

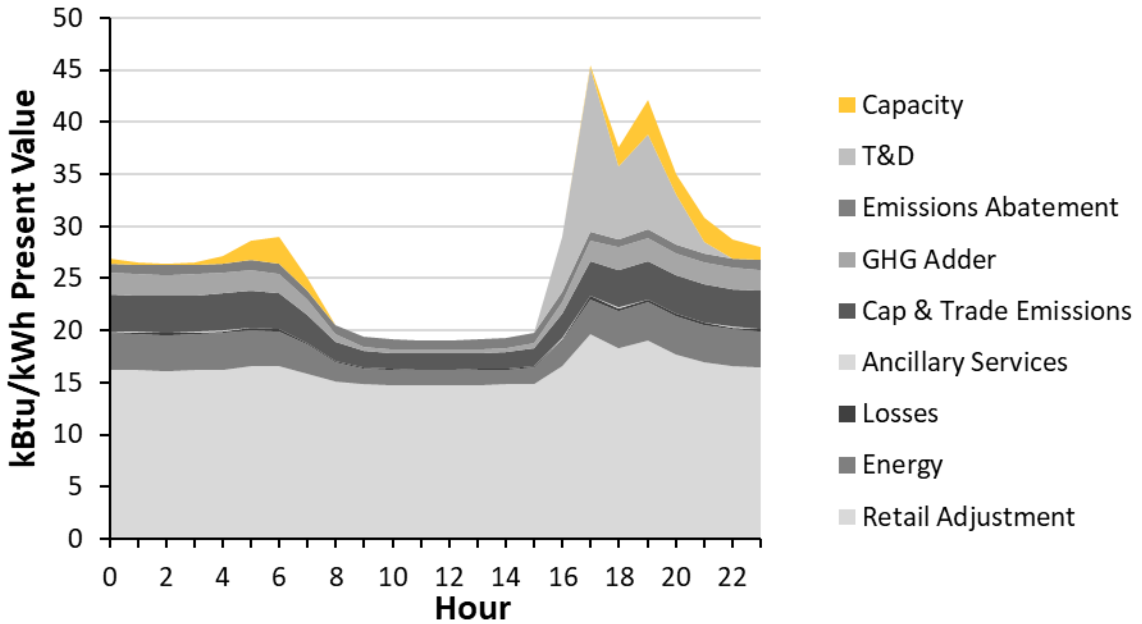


The 2023 allocation factors are used for all years up to and including 2023, and the 2033 shapes are used for 2033 and all subsequent years. A simple linear interpolation is applied to the interim years.

Table 5. Percentage of Electricity Demand Met by Behind-the-Meter PV

Climate Zone	2023	2033	2045
CZ1	4.0%	8.0%	8.5%
CZ2	9.7%	19.1%	20.3%
CZ3	4.0%	8.0%	8.5%
CZ4	5.8%	11.6%	12.3%
CZ5	6.8%	13.6%	14.4%
CZ6	2.9%	6.2%	6.6%
CZ7	8.5%	16.4%	17.4%
CZ8	3.8%	8.2%	8.7%
CZ9	4.5%	9.7%	10.3%
CZ10	9.1%	18.5%	19.7%
CZ11	16.1%	31.1%	33.0%
CZ12	11.5%	22.5%	23.9%
CZ13	10.5%	21.0%	22.3%
CZ14	10.5%	22.0%	23.4%
CZ15	10.6%	22.3%	23.7%
CZ16	5.2%	10.9%	11.6%

3.2.4 GENERATION CAPACITY AVOIDED COSTS



The generation capacity value captures the cost of maintaining a generator fleet with enough capacity to meet each year's peak loads. This cost has historically been defined as the cost of a combustion turbine (CT) less the margins that the CT could earn from the energy markets, with net peak load occurring during warm summer evenings. Analysis from the 2019-2020 CPUC IRP proceeding[14], however, forecasts a departure from this analytical framework in 2030 and beyond. Due to significant levels of renewable generation and energy storage, the IRP analysis projects a change in marginal capacity resources, along with a shift to a net winter peak.

To represent this new analytical framework, this analysis considers three phases of the capacity market, with the following marginal capacity resources:

1. A near-term capacity need driven by planned retirements of existing generation, that sticks to the historical framework. In this period the marginal capacity resource will likely still be the net

[14] 2019-2020 CPUC IRP Preliminary Results, pg 73: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019%20IRP%20Preliminary%20Results%2020191004.pdf

cost of a combustion turbine. A Resource Balance Year of 2023 was selected to represent this near-term capacity need.

2. As costs of renewable generation and energy storage continue to fall, and resource procurement is driven by statewide renewable energy policy goals, the marginal capacity resource will become a combination of renewable generation and energy storage. This phase is projected to occur in the late 2020s. The cost of this marginal capacity resource is calculated in the selected RESOLVE scenario, as the shadow price of generation capacity.

3. Beyond 2030, as the energy storage market becomes saturated, the Effective Load Carrying Capability (ELCC) of incremental renewables and storage diminishes, and the marginal capacity resource will shift to firm dispatchable generation. While there is some uncertainty in what this marginal resource will be, this analysis conservatively assumes that the firm generation will be met by keeping existing Combined Cycle Gas Turbines online, via Fixed O&M.

For near term capacity need in the historical framework, capacity value is calculated as the cost of a combustion turbine (CT) less the margins that the CT could earn from the energy markets. Cost and performance assumptions for a new simple cycle gas turbine, used in the capacity cost calculation, are based on inputs for the 2019-2020 CPUC IRP, along with data from the CEC Estimated Cost of New Utility-Scale Generation in California: 2018 Update[16]. These inputs are displayed in Table 6 and Table 7.

Table 6. 2017 CPUC IRP Performance and Cost Assumptions (2016$)[15]

Metric	Simple Cycle Gas Turbine	Notes
Heat rate (Btu/kWh)	9,300	Costs_Resource_Char, Row 35
Financial Life (yrs)	20	Costs_Resource_Char, Row 40
Installed Cost ($/kW)	$1,250	Costs_Resource_Char, Row 24
Fixed O&M ($/kW-yr)	$12	Costs_Resource_Char, Row 28
Variable O&M ($/MWh)	$1	

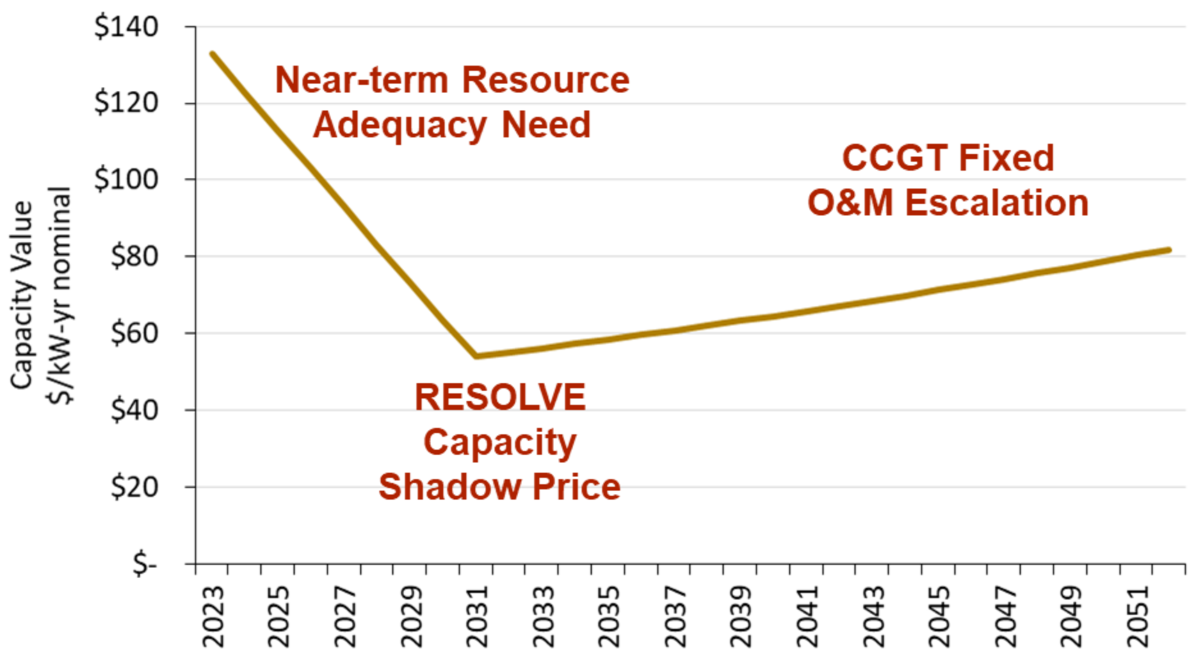
[15] 2017 CPUC IRP, RESOLVE_user_Interface 2017-09-07.xlsm

Table 7. Financing Assumptions in 2022 TDVs[16]

	CEC Report
Financial Life (Yrs)	20
Debt-to-Equity Ratio	55%
Debt Cost	4.8%
Equity Cost	11.50%
Marginal Tax Rate	27.98%

Figure 19 shows the forecasted capacity value used in this analysis. The marginal cost of fulfilling the near-term capacity need, is blended with the 2030 RESOLVE capacity shadow price, and then follows the escalations of Fixed O&M costs for a CCGT.

Figure 19. Capacity Value Forecast



Next, hourly capacity value is calculated based on hourly capacity allocation factors. In the 2023 TDVs, avoided electric generation capacity costs are allocated based on Loss-of-Load-Probability (LOLP). The E3

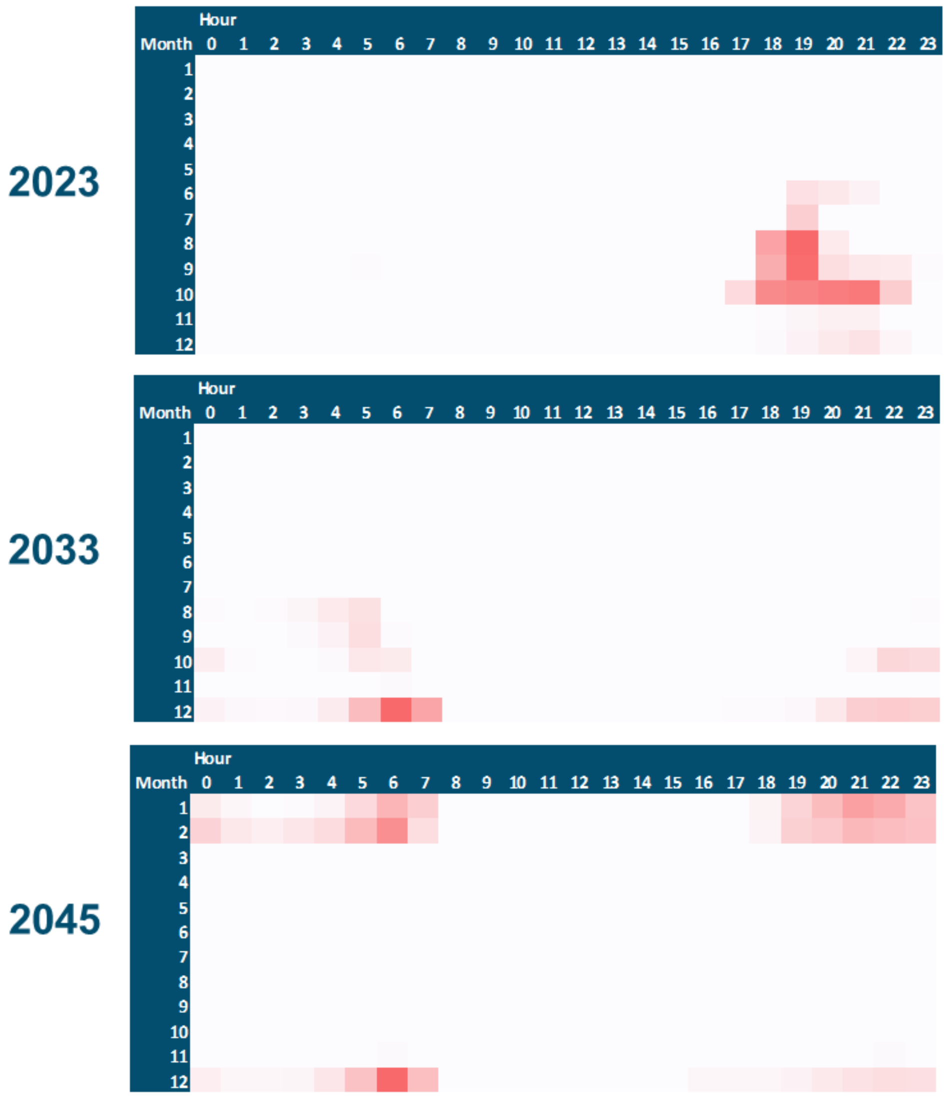
[16] Table B-1, CEC 2019, Estimated Cost of New Utility-Scale Generation in California: 2018 Update: https://ww2.energy.ca.gov/2019publications/CEC-200-2019-005/CEC-200-2019-005.pdf

RECAP model[17] estimates LOLP for each month/hour/day-type combination during the year based on net load in the CTZ22 weather year (gross load net of non-dispatchable resources, i.e. renewables, nuclear, and hydro) and available dispatchable generation (i.e. natural gas plants). These values directly express the likelihood of lost load, and therefore give a more accurate relative weighting among hours.

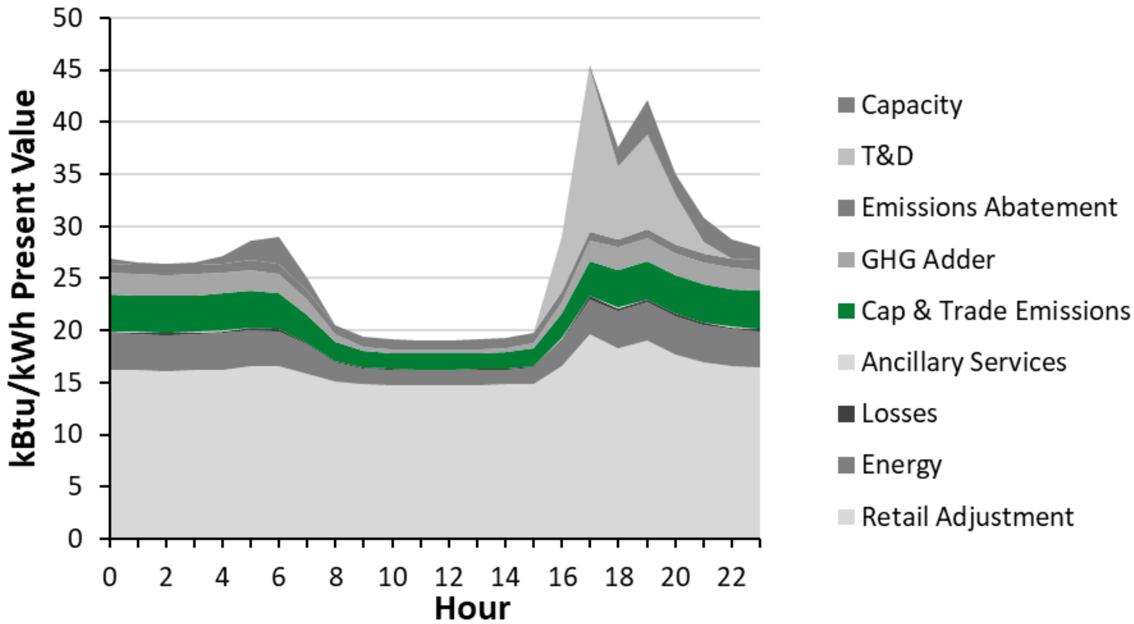
Figure 20 shows the capacity allocation by month-hour average for the three years that RECAP runs were performed – 2023, 2033, and 2045. Notably, 2033 and 2045 begin to show a winter net peak; this is driven by a high penetration of renewables and storage that reduce the net peak that historically occurs in the summer evenings. In wintertime, periods of low availability of renewable generation cause net peak hours to shift into the morning period, typically in the hours before the sun rises.

[17] https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

Figure 20. Generation Capacity Allocation Tables for 2023, 2033 and 2045



3.2.5 AVOIDED CAP AND TRADE EMISSIONS COSTS



The first emissions component – Avoided Cap and Trade Emissions—represents the direct emissions payments from generators as a part of California's Cap and Trade market. The Cap and Trade CO_2 price forecast affects the cost of generation differently in different hours of the year, depending on what type of generator is operating on the margin. In California, it is generally safe to assume that either renewables or natural gas are the marginal "fuel" in all hours. Thus, the hourly short run emissions rate of the marginal generator is calculated based on the same production simulation model results of the marginal generation price curve used elsewhere in the analysis. This hourly emissions curve is adjusted using the same loss factors as the hourly energy value to reflect the emissions reduction consistent with a reduction in retail load.

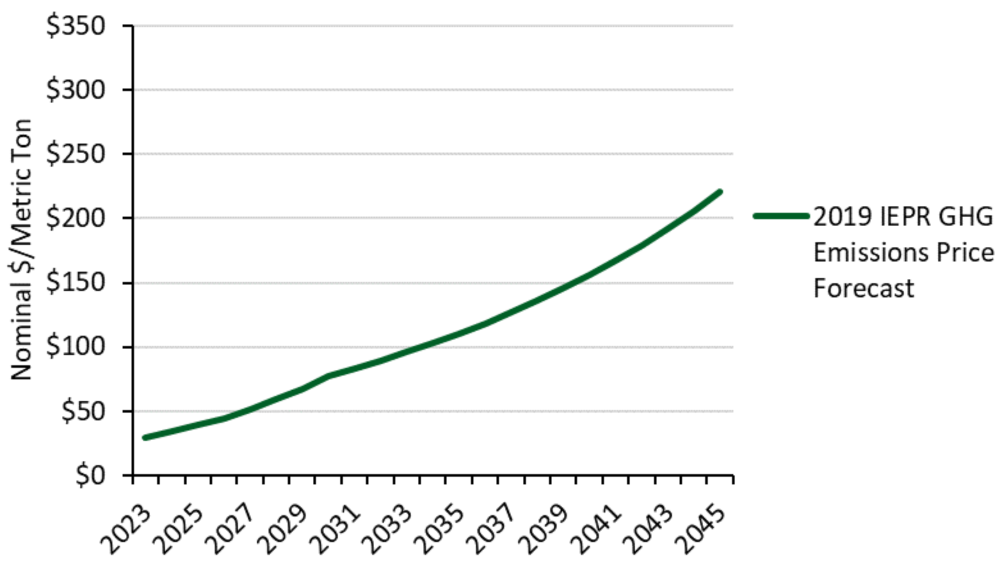
There is a direct link between higher market prices and higher emissions rates since higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum emissions rate based on the physical properties of typical gas turbines. The maximum emissions rates is bounded by the reasonable range of heat rates for the "worst" performing natural gas plants shown in Table 8. In this analysis, renewables are frequently the marginal resource, which would cause a marginal heat rate of zero. Previously, the lower bound was capped at the heat rate of a high efficiency gas plant, but in the range of low, non-zero hourly energy prices (when the price is still greater than zero), it is less clear if the marginal generator is in fact renewable generation, or thermal generators on standby for subsequent hours. Because of this, the lower bound is set at zero, and the marginal heat rate can fall anywhere between 0 and 12,500 Btu/kWh. This can be interpreted as a probabilistic approach or a weighted average of the marginal resource in the range between zero and the heat rate of an efficient natural gas generator (~6,500 Btu/kWh).

Table 8. Bounds on electric sector carbon emissions

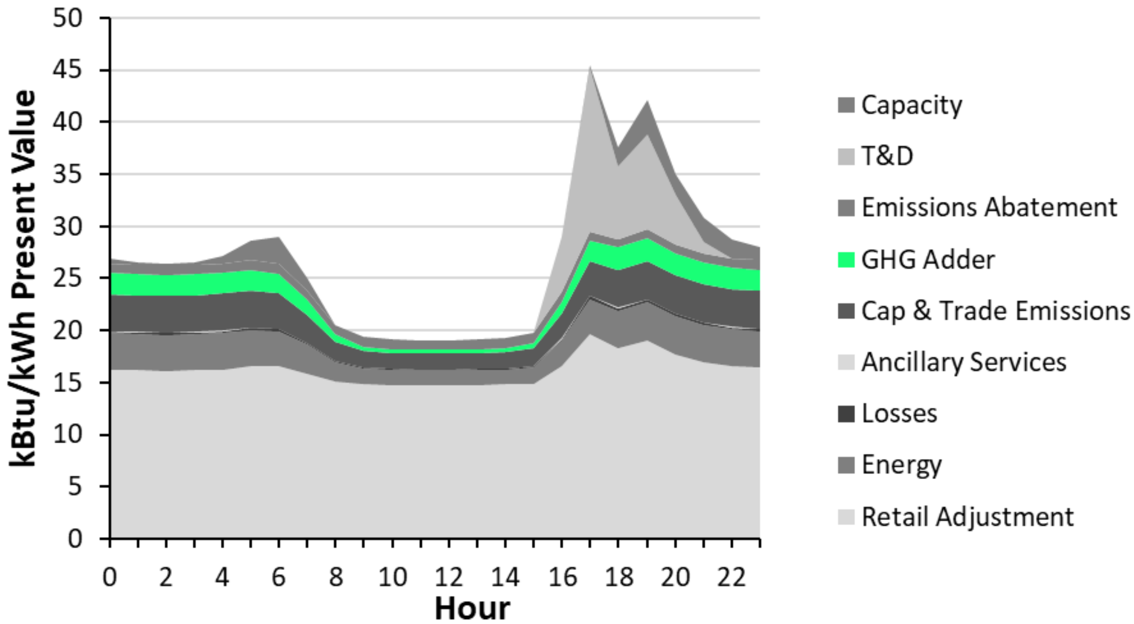
	Upper Bound - Proxy Low Efficiency Plant	Lower Bound – Renewable Generation
Heat Rate (Btu/kWh)	12,500	0
Emissions Rate (tonnes/MWh)	0.664	0

The CO2 emissions price forecast was taken from the 2019 preliminary IEPR, which projects nominal CO2 prices from 2023-2033, we then extrapolate to 2052 using a linear trend. The 2019 IEPR Cap and Trade CO_2 Price Forecast is displayed in Figure 21. Note that previous TDV cycles reported CO_2 prices in units of short tons; 2022 TDV now uses metric tonnes, as is industry standard.

Figure 21. Cap and Trade CO_2 Price Forecasts used in the 2022 TDV analysis



3.2.6 AVOIDED GHG PROCUREMENT COSTS



Previous iterations of TDV have used RPS Adder as a cost stream to represent the change in renewable purchases that correspond with changes in load. For example, a reduction in electricity consumption due to energy efficiency would result in a cost savings from avoided renewable purchases. In the recent CPUC IRP cycles, the binding constraint for the electricity sector has changed from the Renewable Portfolio Standard (RPS), to an electricity sector emissions limit. This means that between parallel RPS and emissions policy targets, the emissions target is more stringent; by meeting 2030 electricity sector emissions limits, California is projected to surpass RPS goals in 2030[18].

To remain consistent with supply side procurement constraints, the 2022 TDV uses Avoided GHG to represent the cost premium of achieving cleaner energy targets driven by changes in demand side load. The root of this metric is the assumption that increases in load will result in short-term increases in electricity generation. Depending on the time of day, the increase in generation may yield increased emissions. In order to comply with annual sector-wide emissions limits, the emissions increases must be

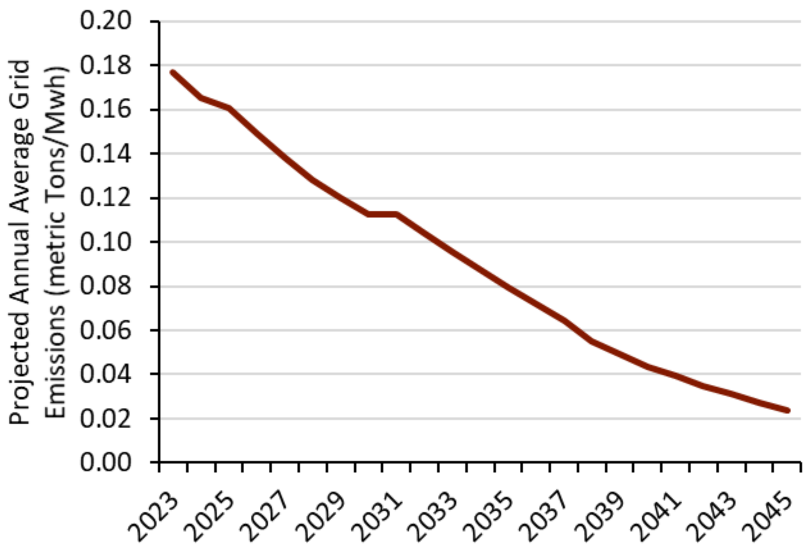
[18] Page 80, 2019-2020 CPUC IRP: Preliminary Results https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019%20IRP%20Preliminary%20Results%2020191004.pdf

offset with additional supply side emissions reductions; these reductions will be achieved by greater procurement and integration of renewable generation. This manifests itself within the TDV framework metric in two ways.

First, for reduced electricity consumption due to energy efficiency, emissions will be reduced, thus avoiding the costs of emissions reductions through the supply side costs of procuring and integrating renewable generation. Second, for increases in electric load from measures like fuel switching, there will be an associated cost with meeting supply side emissions targets for the incrementally higher electricity consumption. For new load, this represents the costs of moving from short-run source energy/short-run emissions to long-run source energy/long-run emissions. In order to account for long-run source energy, it is critical to account for the costs of achieving the long-run changes supply side resources.

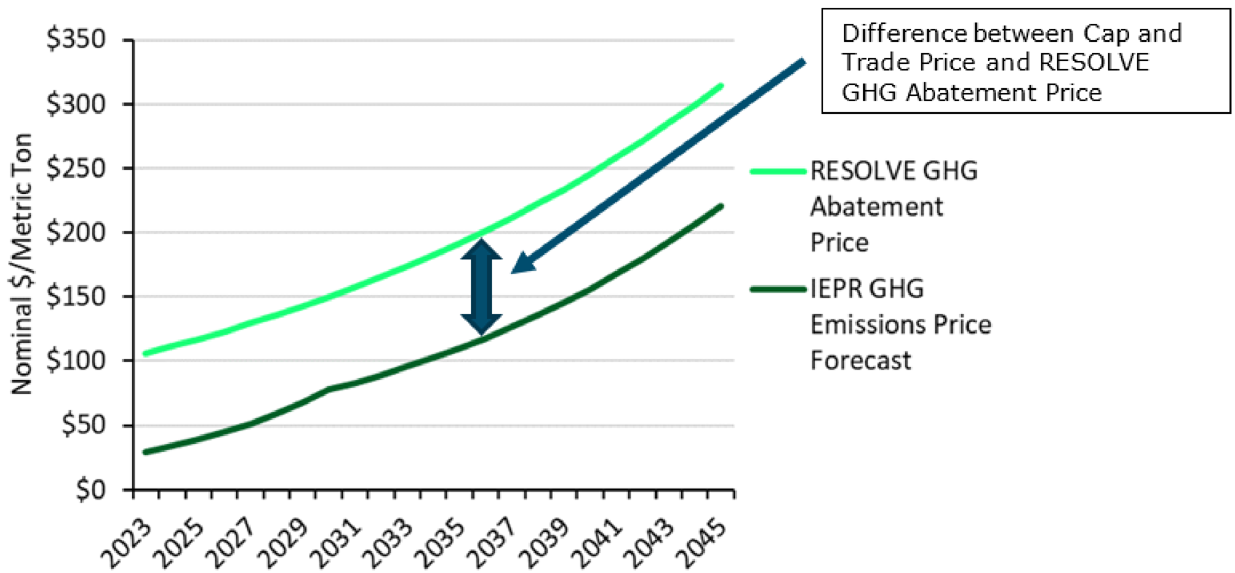
The GHG Adder field is calculated by multiplying the hourly amount of emissions reductions needed by the annual cost of achieving supply side emissions reductions. The amount of emissions reductions required for a given hour is calculated as the difference between hourly short run marginal emissions, and a target annual emissions intensity. The annual emissions intensity, shown in Figure 22, is defined by the PATHWAYS scenario used in this analysis, which corresponds with an 80x50 emissions reduction scenario.

Figure 22 California Electricity Sector Annual Emissions Intensity Target Corresponding to 80 x 50 Emissions Reductions

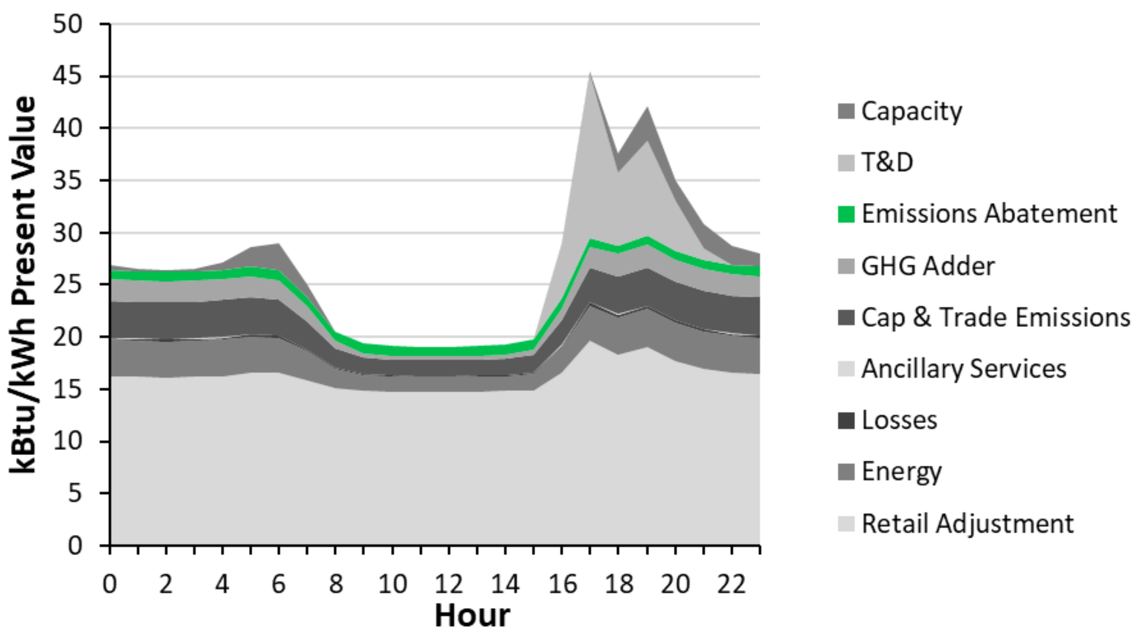


The RESOLVE-based supply side GHG Abatement cost, as reported in Figure 23, includes cap and trade market costs within in. Therefore, the cost of the GHG Adder is only the RESOLVE GHG Abatement cost that is incremental to the Cap and Trade price forecast. The GHG Adder cost per metric ton of CO_2 is calculated as the difference between the reported RESOLVE price and the Cap and Trade price forecast.

Figure 23. Incremental GHG Abatement Priced Used to Evaluate GHG Adder



3.2.7 ECONOMY-WIDE EMISSIONS ABATEMENT



Economy wide emissions abatement cost is the cost above and beyond both Cap and Trade market participation and achieving electricity sector renewable generation targets. Assuming that there is a cost to achieving California's emissions targets beyond the Cap and Trade market price ceiling, and that there is a binding statewide emissions budget, one can conclude that increasing CO_2 emissions in one sector of the economy requires equal reductions in another sector of the economy, and that there is an incremental cost to those emissions reductions. Therefore, any otherwise unaccounted for incremental emissions or emissions reductions should be evaluated at an economy-wide cost of emissions abatement.

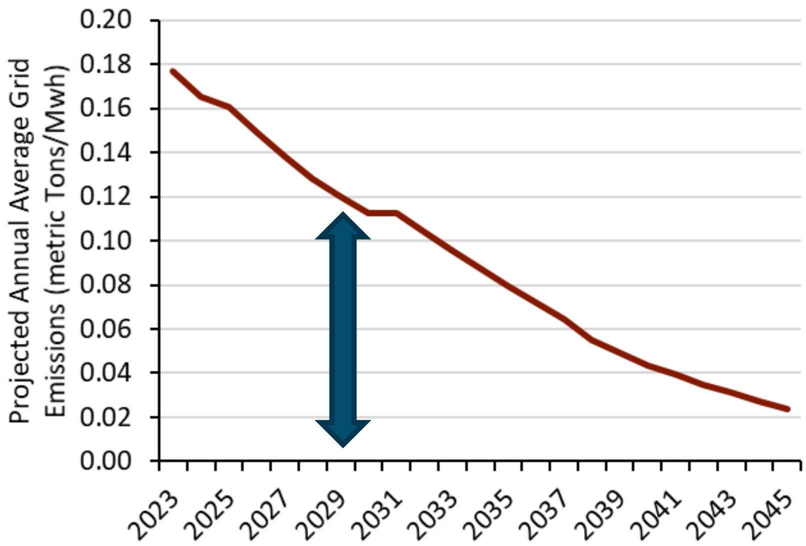
To determine a true economy-wide emissions abatement cost, one would need to accurately characterize the market potential and costs of all emissions reductions strategies and then create a supply curve that accurately projects these costs. Such a supply curve would need to forecast cost declines for technologies that are still in the research and development phase of their product lifecycle. While there is a large body of research on potential solutions, along with rough costs, there is not a definitive source for a full supply curve of emissions reductions strategies that is sufficient to generate a marginal emissions abatement cost as California nears its economy wide emissions reductions targets.

In absence of a better-defined number, the 2022 TDV analysis assumes that any incremental emissions reductions needed to achieve California's emissions reductions targets will come from the electric supply sector. The electricity sector has both a quantifiable emissions reductions cost projection and is subject to binding state emissions regulation. Other emissions-focused state programs, such as the Low Carbon Fuel Standard, or fuel economy standards have implicit emissions abatement prices that typically exceed the marginal cost of electricity supply side reductions[19].

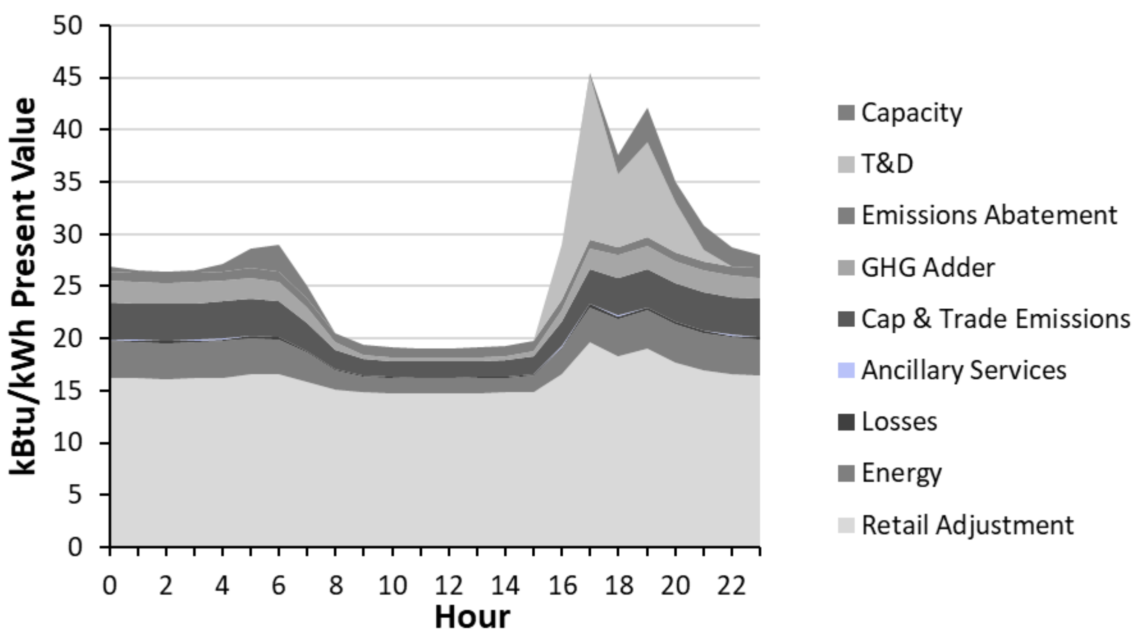
For electricity TDVs, the economy wide emissions abatement cost is defined as the additional emissions beyond existing supply side procurement constraints, multiplied by the incremental cost of abating those emissions. In this code cycle, the additional emissions are equal to the difference between the long run electricity emissions intensity, and zero, shown in Figure 24. The economy wide emissions abatement cost, in this case, is also the RESOLVE GHG abatement cost that is incremental to the Cap and Trade price forecast.

[19] For example, the average price for LCFS credits in 2019 was $192/Metric ton CO_2. See ARB LCFS Monthly Credit Transfer Activity Report: https://ww3.arb.ca.gov/fuels/lcfs/credit/Jan%202020%20-%20Monthly%20Credit%20Transfer%20Activity.pdf

Figure 24 California Electricity Sector Annual Emissions Intensity Target for Economy-wide emissions abatement

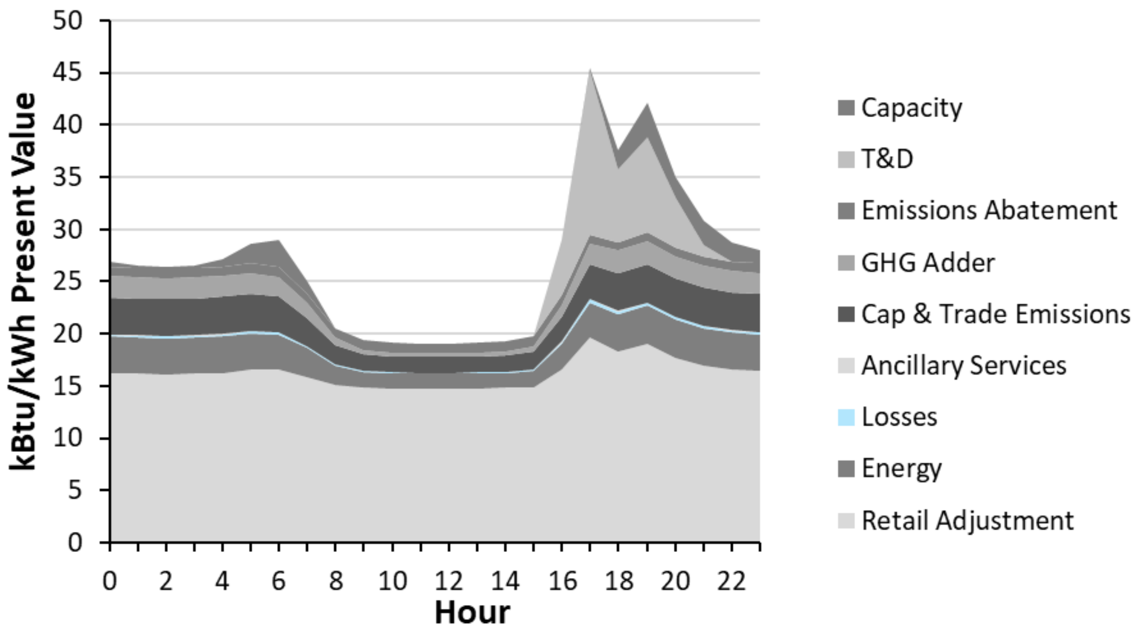


3.2.8 AVOIDED ANCILLARY SERVICES COSTS



Continuing the methodology used in the 2019 TDV analysis, the value of avoided ancillary services (A/S) procurement is treated as a flat percentage multiplier on top of the energy value. This approach reflects the fact that the value of ancillary services is mildly correlated with the value of energy in any given hour, but other factors also affect the value of A/S. Since the overall value of A/S remain relatively small in the market, it is appropriate to use an approximation, based on a multiplier of 0.5% of the energy value in each year. This multiplier is based on California Independent System Operator (CAISO MRTU) market prices for energy and reserves from 2009-2010. The new CAISO market design has substantially reduced ancillary service costs. Load reduction (e.g., efficiency) is only credited with the value of avoided procurement of spinning and non-spinning reserves.

3.2.9 AVOIDED COSTS OF ELECTRIC LOSSES

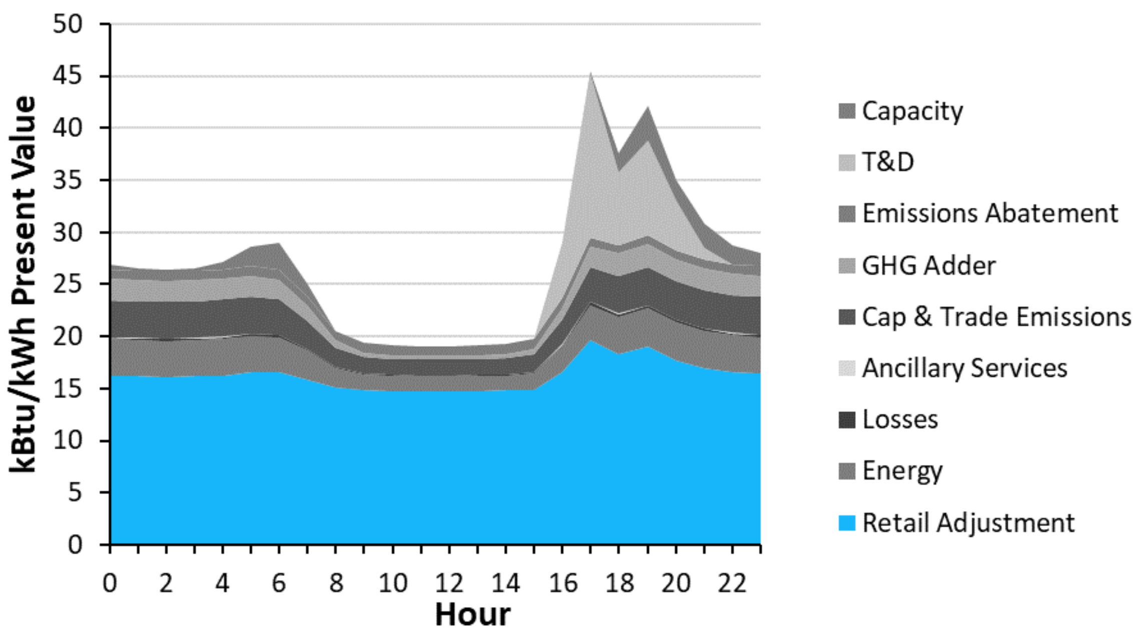


The utility-specific loss factors have been retained from 2013, 2016, and 2019 TDV analyses, and are shown in Table 9.

Table 9. Electric loss factors by utility and season

Description	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	1.083	1.083	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068
Generation Peak	1.109	1.084	1.081
Transmission Peak	1.083	1.054	1.071
Distribution Peak	1.048	1.022	1.043

3.2.10 RETAIL RATE ADJUSTMENT



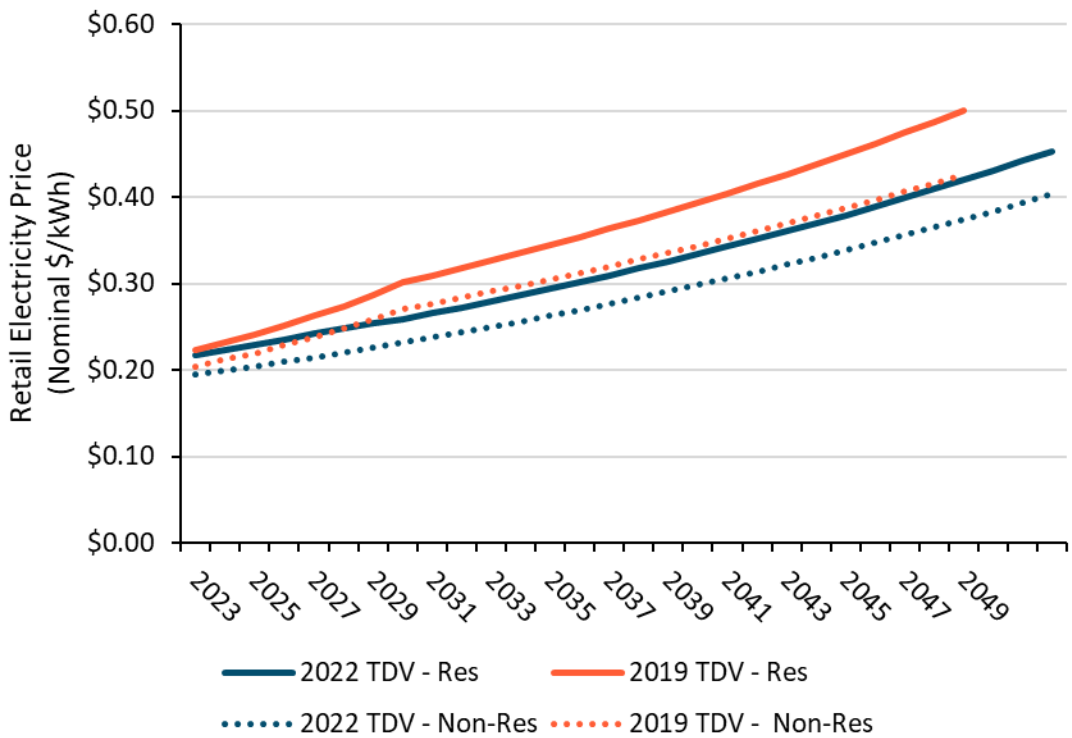
The final step in the process of developing TDV cost values is to use the Retail Adjustment to adjust the hourly wholesale cost of energy up to the equivalent of the retail cost of energy. This step is done to ensure that the energy efficiency measures considered in the Title 24 standards process are roughly cost effective to the building owner. In other words, the TDVs reflect a modified (time-dependent) participant cost test approach to avoided costs.

A statewide retail rate forecast for residential and nonresidential customers is developed for the electricity TDVs. The electricity rate forecasts for previous cycles of TDV were developed directly from the IEPR. The preliminary 2019 IEPR includes retail rate forecasts for a mid-demand load and current policy mandates.

The IEPR calculates average residential and commercial rates for PG&E, SCE, SDG&E, LADWP, and SMUD through 2030. For the 2022 TDVs, the utility-specific rates are combined into a statewide weighted average using electricity consumption forecasts from 2019 IEPR Form 1.1. After 2030, the rate forecasts (modified by the multipliers described above) are escalated using the compound average growth rate observed from 2023 through 2030 (2.6%/yr nominal increase for residential and 2.6%/yr for non-residential).

The resulting assumed rates for the 2022 TDVs are shown for residential and non-residential customers and compared to 2019 TDV retail rates in Figure 25.

Figure 25. Comparison of Electricity Retail Rate Forecasts in 2019 and 2022 TDVs



3.2.10.1 Partially Scaled Retail Rate Adder

In previous code cycles of TDV, the TDV Retail Rate Adder cost component was spread evenly across all hours of the year; this reflected an even allocation of costs. The original intent of this even allocation, or "flat retail rate adder" was to be a rate design forecast that was agnostic to the discrete rate design choices that will occur in each new rate cycle over the 30 year lifetime of the new buildings.

As TDV was designed as a cost-effectiveness test for energy efficiency measures, this placed special focus on a principle of encouraging efficient use. At the time that TDV was first developed, retail rates for residential and small commercial customers had a flat (did not vary by hour of the day) energy price. The flat TDV adder was consistent with such flat pricing, while allowing the marginal cost-based portion of TDV to reflect the time varying nature of electricity costs. With the advent of new dispatchable distributed energy resources such as energy storage and flexible loads, as well as the movement in California away from flat energy rates, there is cause for change in the flat adder assumption.

To reflect the changing condition of the grid, retail rates that encourage optimal behaviors of dispatchable DERs may need to be more directly aligned with marginal cost of service. From the standpoint of encouraging efficient use while recovering the revenue requirement, having an allocation of fixed costs that are partially scaled to the marginal cost of service would allow a hypothetical utility to incentivize the installation and optimal operation of dispatchable DERs while maintaining utility cost recovery. From the standpoint of fair apportionment of costs, a flat retail rate adder allocates fixed costs to the efficiency losses from shifting flexible loads or charging/discharging battery storage, when those actions incur no additional fixed cost. Partially scaling the allocation of fixed costs removes this cost penalty to dispatchable DERs. Scaling the fixed costs to marginal cost of service, however, must be counter-balanced by the need for costs to be apportioned fairly among customers. Setting a rate signal where fixed costs are allocated based 100% on marginal cost of service, for example, would allow some customers to use load shifting to avoid a disproportionally large amount of fixed costs relative to other customers.

To achieve the desired balance of a partially scaled retail rate adder in the 2022 TDV code cycle, a range of scaling factors from 0% to 100% was analyzed and tested on potential building design measures in CBECC-Res and CBECC-Comm. Special consideration was given to the effect on representative energy efficiency measures, behind the meter solar, and energy storage. Ultimately, a scaling factor of 15% was selected to balance the need for incentivizing optimal dispatch of energy storage with the need to incentivize energy efficient building design.

Putting this into practice, 85% of the Retail Rate Adjustment is set as flat, and allocated evenly across all hours of the year, denoted as the “Constant Retail Rate Adjustment”. The remaining 15%, denoted as the “Proportional Retail Rate Adjustment” is allocated proportionally based on the remaining TDV cost components, which represent the hourly marginal cost of service. Hours that have high marginal cost of service (ex. peak summer evenings) have a larger amount of the proportional retail rate adjustment, while low cost hours (ex. spring midday curtailment hours) have a lesser proportion of the scaled retail rate adjustment. Altogether, this creates a more optimal dispatch signal for dispatchable Distributed Energy Resources and maintains a strong energy efficiency signal for building design measures, while staying relatively agnostic to other future rate design considerations.

$$Constant\ Retail\ Rate\ Adjustment_{h,y} = (1 - .15) * Retail\ Rate\ Adjustment_y * \frac{1}{8760}$$

$$Proportional\ Retail\ Rate\ Adjustment_{h,y} = .15 * Retail\ Rate\ Adjustment_y * \left(\frac{Marginal\ Cost\ of\ Service_{h,y}}{\sum_{h=1}^{8760} Marginal\ Cost\ of\ Service_{h,y}}\right)$$

Where $Retail\ Rate\ Adjustment_y$ is the total retail rate adjustment for year, *y*, and $Marginal\ Cost\ of\ Service_{h,y}$ is the sum of all other TDV cost components (Avoided Energy, Avoided Capacity, etc), for hour, *h* and year, *y*. To demonstrate the proportional allocation of the retail rate adjustment, Figure 26 and Figure 27 show the hourly TDV cost components and the corresponding constant/proportional retail rate adjustments, for the summer and non-summer months, respectively.

Figure 26: Climate Zone 12 hourly TDV cost components and corresponding retail rate adjustments, averaged across weekdays in June-September

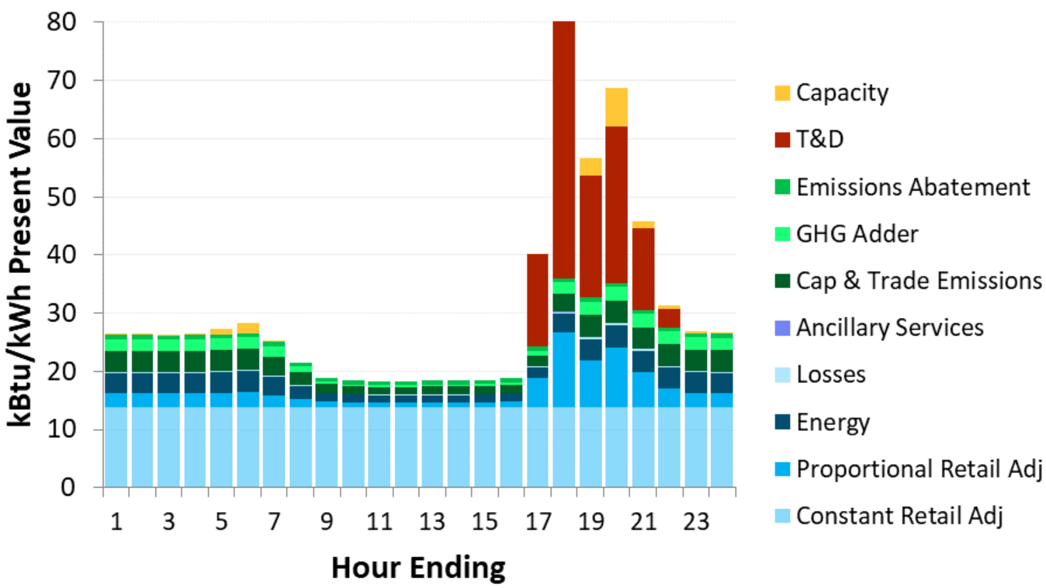
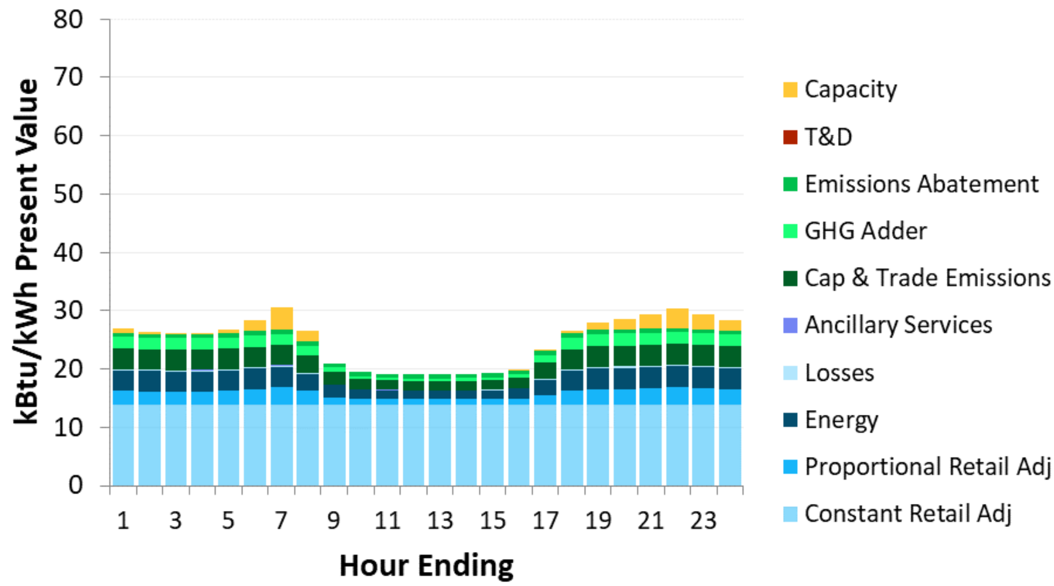
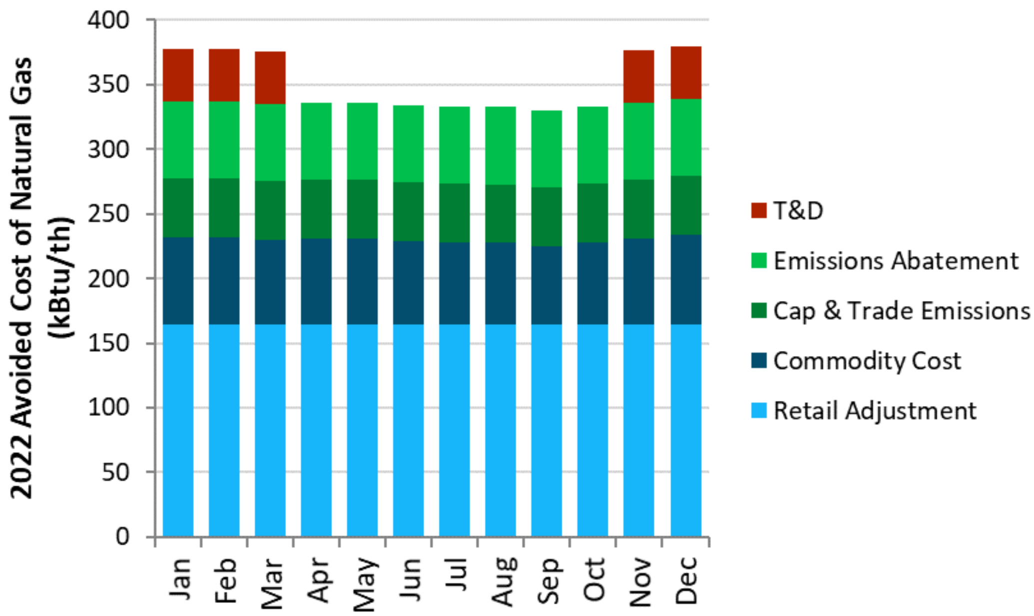


Figure 27 Climate Zone 12 hourly TDV cost components and corresponding retail rate adjustments, averaged across weekdays in October-May



3.3 Natural Gas 2022 TDV Inputs



3.3.1 OVERVIEW OF AVOIDED COSTS OF NATURAL GAS

The natural gas TDV is based on a long-run forecast of retail natural gas prices and the value of reduced emissions of carbon dioxide. Natural gas avoided costs are more straight-forward than electricity TDV, due the variation in marginal gas costs being on a monthly scale, instead of an hourly scale. Electricity TDV variation is on an hourly scale, because the electricity generation landscape is more heterogeneous than the natural gas system, with many types of power plants with varying efficiencies and fuel types. Variation in natural gas costs are driven by monthly and seasonal variations of markets and utilization of infrastructure. The components are listed in Table 10.

Table 10. Components of Time Dependent Valuation for natural gas

	Component	Description
Marginal Natural Gas Avoided Costs	Wholesale Commodity Cost	Estimate of monthly commodity cost for retail natural gas. This includes the wholesale costs for blend of biogas and hydrogen that are consistent with the over-arching scenario
	Cap & Trade Emissions	The direct cost of carbon dioxide emissions (CO2) associated with end use natural gas consumption
	Economy-wide Emissions Abatement	The costs of abating combustion and leakage emissions beyond cap and trade market prices. Analogous to previous Carbon Externality. This cost is not included in retail rate forecasts, and therefore is added incrementally to TDV
	Marginal Transmission & Distribution Cost	The marginal cost of expanding and maintaining gas distribution infrastructure
Retail Rate Adder		Wholesale Commodity Cost, Cap & Trade Emissions, and Marginal Distribution Cost components above are scaled to match the average retail rate through the retail rate adder.

Each component is estimated on a monthly or annual basis and forecasted into the future for 30 years. The monthly granularity of the avoided costs is obtained from several sources. Table 11 summarizes the methodology applied to each component to develop the monthly, or annual price shapes. The final natural gas TDV outputs, are formatted to be applied to hourly end-use consumption.

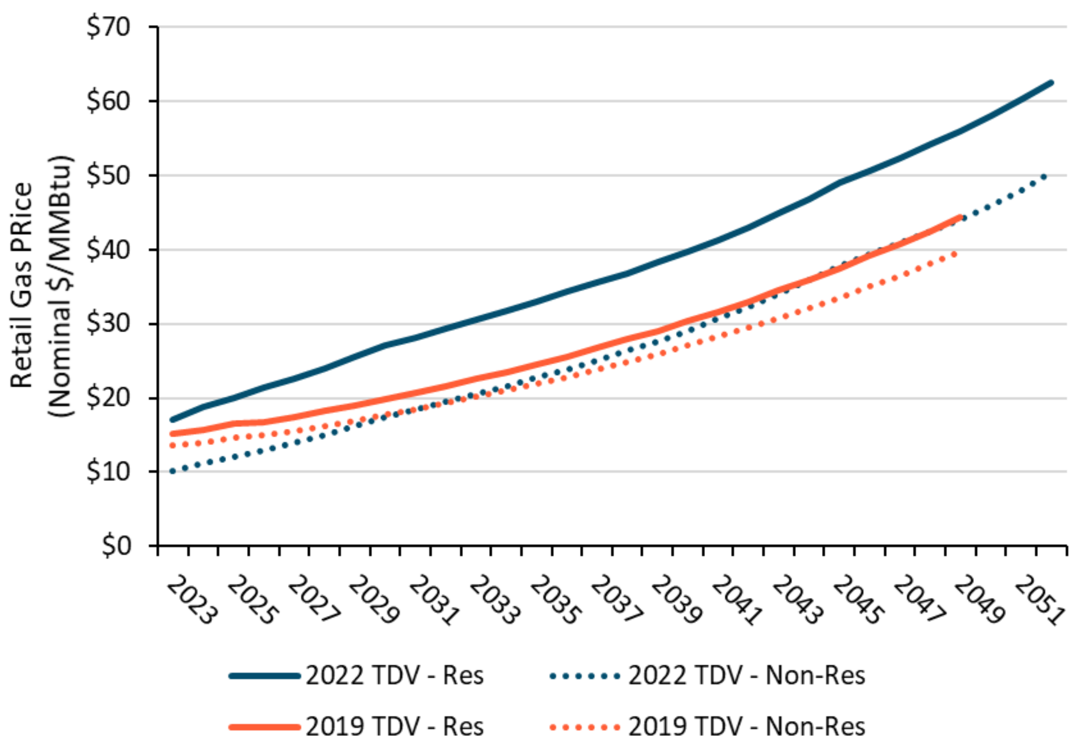
Table 11. Summary of methodology for natural gas TDV component forecasts

Component	Basis of Annual Forecast	Basis of Monthly Shape (if applicable)
Wholesale Commodity Cost	CEC 2019 IEPR price forecast	NYMEX historical market data
Cap and Trade Emissions	CEC 2019 IEPR Cap and Trade price forecasts, applied to annual projection of emissions intensity of retail gas	No monthly variation
Economy-wide Emissions Abatement	Cost of economy-wide marginal emissions reductions, beyond Cap & Trade	No monthly variation
Marginal Transmission & Distribution Cost	Historical gas transportation marginal costs	Applied to winter months
Retail Rates	E3 Projections from Natural Gas Distribution in California's Low-Carbon Future report	No monthly variation

3.3.2 NATURAL GAS RETAIL RATES

The natural gas retail price forecast is taken from results from the recent study on Natural Gas Distribution in California's Low-Carbon Future[20] and updated to be consistent with recent recorded rates and final IEPR wholesale natural gas prices. The increase in volumetric costs comes from a combination of lower throughput in the gas pipeline, combined with a higher commodity cost that incorporates a blend of renewable gas in the pipeline. The annual end user prices are also adjusted to reflect monthly variations in natural gas commodity costs. Those adjustment factors are the same as those used for the 2019 TDVs and are based on historical NYMEX monthly natural gas price shapes at Henry Hub. The annual average natural gas retail price levels used in the natural gas TDVs are shown in Figure 28 below.

Figure 28. Comparison of gas retail rate forecasts in the 2022 and 2019 TDVs

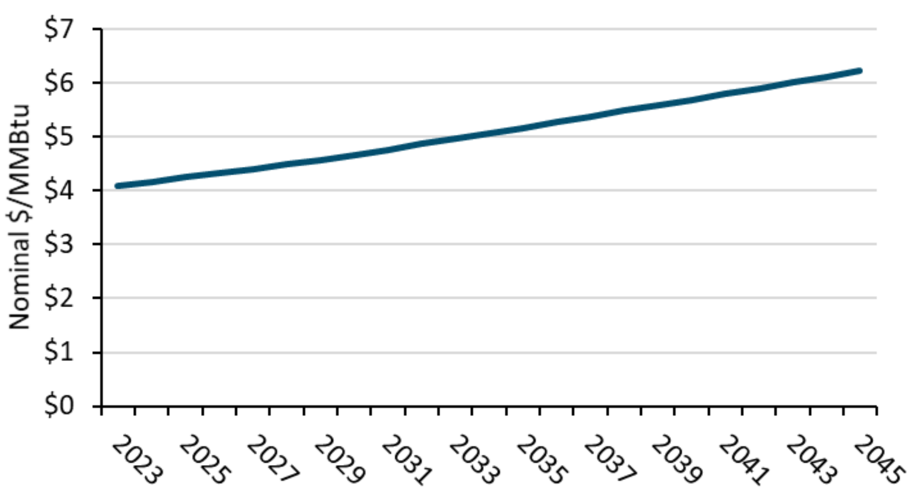


[20] "Multi-prong with Slower Building Electrification" Scenario from Draft Report: Natural Gas Distribution in California's Low-Carbon Future, 2019. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-D.pdf

3.3.3 WHOLESALE COMMODITY COSTS

In the 2022 TDV, retail natural gas for end use consumption is assumed to include a blend of natural gas, biogas, and hydrogen, that is consistent with the over-arching PATHWAYS scenario and technical constraints. For the purposes of natural gas TDVs, we define the commodity price as the average of the forecasted monthly value of the PG&E Backbone and SCG Needles hubs as defined in the CEC 2019 Preliminary IEPR[21] for natural gas, along with the forecasted costs for biogas and hydrogen. The method for estimating commodity prices in the IEPR is based on forecasted annual natural gas commodity prices from the World Gas Trade Model and transportation rates from interstate, and intrastate transportation rates. Figure 29, below, shows the forecasted California average annual natural gas commodity prices used in the 2022 TDV analysis.

Figure 29. California Natural Gas Annual Commodity Cost (average of PG&E Backbone and SCG Needles)

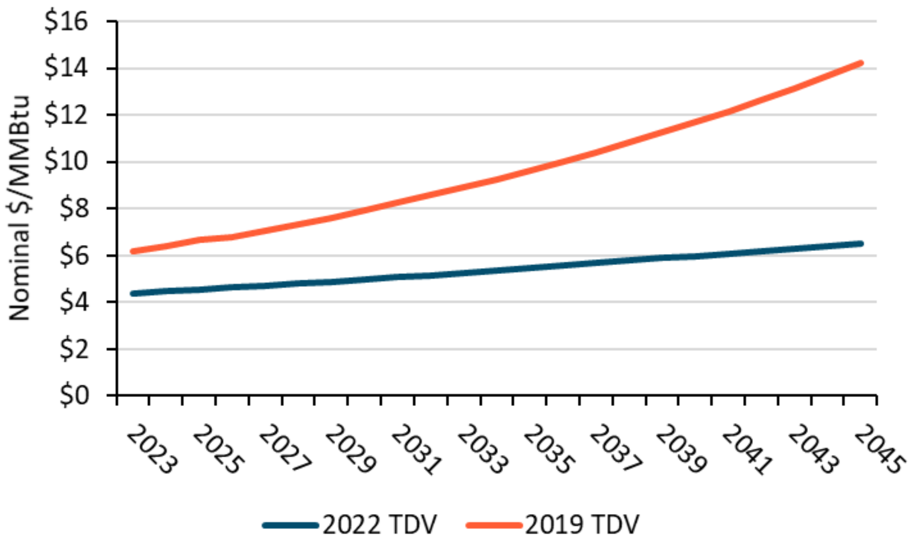


For the purposes of calculating fuel costs for electric generation used in the development of the electric TDV values, we use the natural gas burner tip prices from the 2019 Preliminary IEPR. These are calculated as the commodity price above, plus appropriate transportation rate (tariff) is added to account for transportation to the electric generator as inputs to our electric generator gas price forecast. We have used the average transportation price from the same two hubs (PG&E Backbone and

[21] 2019 IEPR Gas Price Forecasts were provided to E3 directly by the CEC.

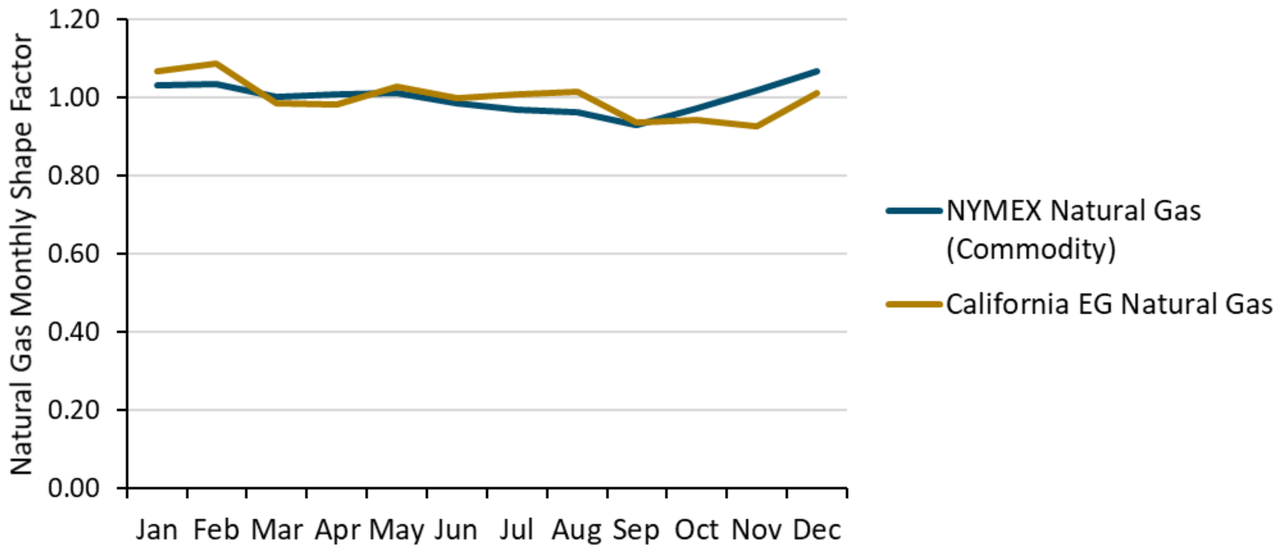
SCG Needles), which adds $0.30/MMBtu nominal to the commodity price in every year. Figure 30 shows the burnertip costs (commodity and transportation costs) for the 2022 cycle compared to the 2019 cycle. Gas burnertip costs are notably lower than the gas burnertip costs used in the 2019 code cycle. This is due to a recent drop in wholesale natural gas prices. Outside of the natural gas TDV, this puts downward pressure on marginal wholesale electricity prices for electricity TDVs.

Figure 30. California Natural Gas Burnertip Costs (average of PG&E Backbone and SCG Needles)



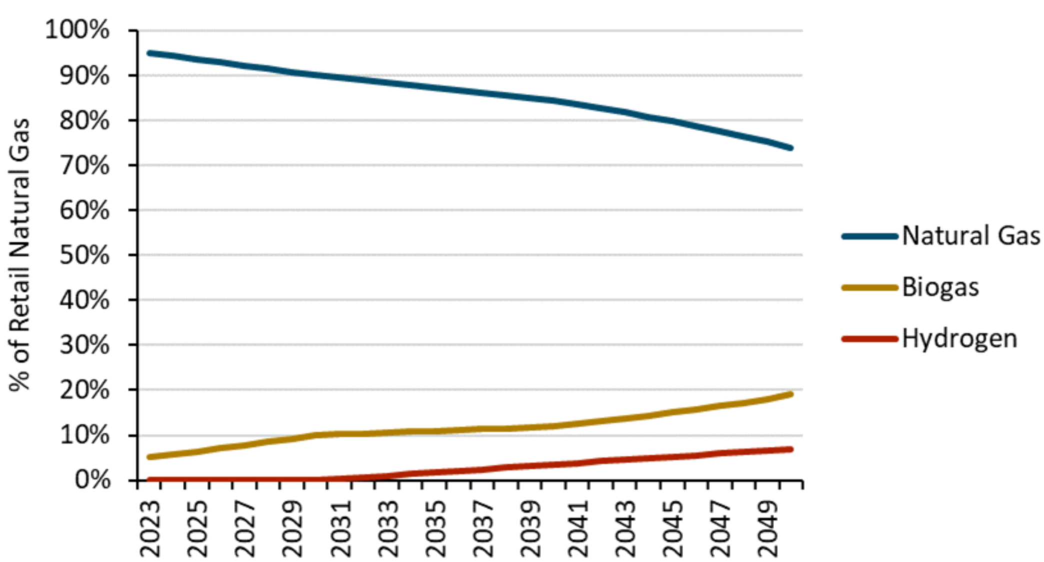
The annual average forecast is further disaggregated into months using a monthly shape based on NYMEX market data. The same monthly price shape has been used for this 2022 update as used in the 2019 analysis. The monthly shape factors used to define the seasonal shape over the course of each year are shown in Figure 31 for natural gas commodity and burnertip costs.

Figure 31. Monthly shape factors for California natural gas commodity and burnertip prices



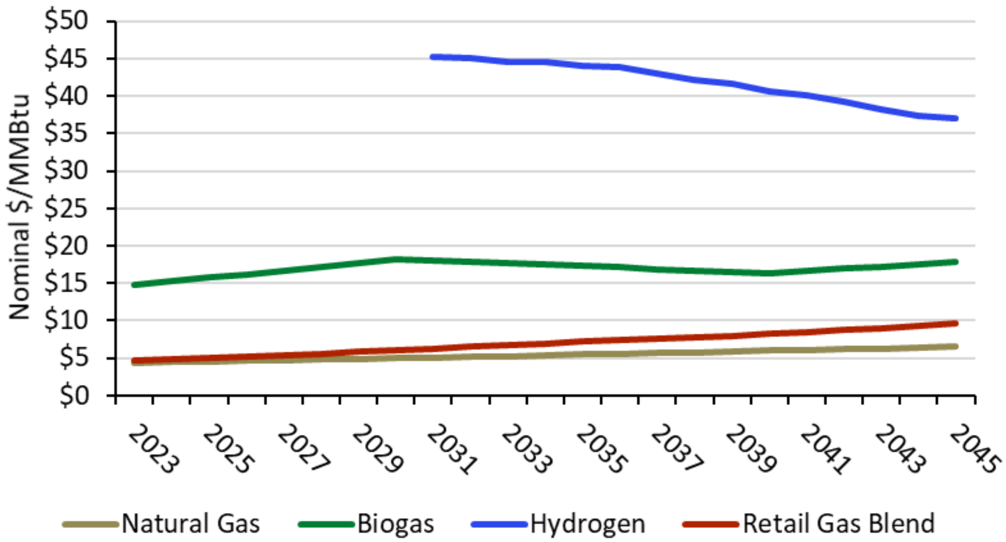
In order to remain consistent with the 80 x 50 scenario, renewable gas is blended into the retail gas pipeline, as shown in Figure 32. This blend forecast includes 10% biogas by 2030, and 7% hydrogen by 2050. This renewable gas blend is only used for retail gas consumption and is not applied to gas used for electricity generation.

Figure 32 Retail natural gas fuel blend used in 2022 TDV



The renewable gas components of the retail gas blend come at a cost premium, as shown in Figure 33. The "Retail Gas Blend" shows the weighted total commodity cost for the retail gas, by year. This blend is only used for retail end use consumption and is not assumed to reduce the carbon intensity of natural gas used in the electricity generation fleet.

Figure 33. Retail Gas Blend Commodity Costs



3.3.4 CAP AND TRADE EMISSIONS COST AND ECONOMY-WIDE EMISSIONS ABATEMENT COST

Emission values are calculated based on the emissions rates of combusting natural gas in typical appliances, adjusted for renewable gas in the pipeline, as well as methane leakage in the gas distribution system. The CO_2 emissions rate for natural gas combustion is derived from the EIA at 0.0531 metric tons/MMBtu[22]. For both biogas and hydrogen, it is assumed that the emissions intensity of combustion is zero. An emissions intensity of zero for renewable gas relies on assumptions that creating biogas is a carbon neutral process and assumes that hydrogen is produced using off-grid renewables.

In general, we seek to apply the same methodology to the development of the natural gas TDVs as to the electricity TDVs, in order to maintain as much parity between the fuel types as possible. In the case

[22] EIA **https://www.eia.gov/tools/faqs/faq.php?id=73&t=11**

of greenhouse gas emissions, natural gas retail rates are assumed to include CEC mid-IEPR carbon prices. Because of the retail rate adjustment, inclusion of a Cap and Trade carbon price does not impact the shape or level of the natural gas TDVs, but this breaking out this cost does provide greater clarity into the TDV components.

Additionally, the incremental cost of economy-wide emissions abatement above the Cap and Trade emissions cost is applied to the same carbon intensity of the blended retail natural gas. Since the economy-wide emissions abatement cost is not included in retail rate forecasts, this cost component is added on top of retail rate forecasts.

3.3.4.1 Methane Leakage

As discussed in the addendum 2022 TDV Non-Combustion Emissions Report (Appendix A), methane leakage also contributes to the CO_2-equivalent emissions of retail natural gas consumption. Because methane has a higher GWP warming potential when not combusted, one therm of leaked methane has a proportionally higher climate impact than one therm of combusted methane. Assuming a 20-yr global warming potential for un-combusted methane of 72[23], the GWP of leaked methane is 1.394 metric tons CO_2-equivalent/MMBtu[24].

To account for methane leakage, 2022 TDVs include a "methane leakage adder" that is applied to the economy-wide emissions abatement cost component of TDV. The methane leakage adder is split into categories for 1) Oil & Gas Production and Processing, 2) Natural Gas Transmission and Distribution, and 3) Residential Behind-the-Meter leakage, based on data from the 2017 California Air Resources Board GHG Inventory[25]. Leakage adders for Production and T&D are calculated by taking the CARB-reported CO_2-equivalent methane leakage and dividing by CO_2 emissions from total natural gas consumption in

[23] Uses AR4 GWP, consistent with CARB emissions tracking. CARB/IPCC: **https://ww2.arb.ca.gov/ghg-gwps**

[24] Methane's GWP of 72 is calculated on a mass basis (per kg of CH_4 instead of per kg of CO_2); combusting 1 kg of CH_4 does not yield 1 kg of CO_2. To make a fair comparison of the GWP of leaked vs combusted methane on a per therm basis, it is necessary to compare the molar mass of the gasses before and after combustion. CO_2/CH_4 has ratio of (12.01+2*16)/(12.01+4*1.01) = 2.74. Combining a GWP of 72 for methane with this additional ratio of 2.74, uncombusted methane is ~26.26

[25] See CARB GHG Inventory (Economic Sector categorization) data: **https://ww2.arb.ca.gov/ghg-inventory-data**

California. Residential behind-the-meter leakage is calculated by dividing CARB-reported CO_2-equivalent emissions by all residential gas consumption in California. These numbers are displayed in Table 23.

Scientific literature generally reports natural gas leakage as a percentage of natural gas consumption; to help benchmark to these studies, Table 12 also includes the implied leakage rate. The leakage rate is calculated by dividing the leakage adder by dividing the leakage adder by the ratio of 26.26[24], which compares GWP of leaked methane gas with combusted methane gas on per therm basis.

See Section 6.4A.4 for further detail on methane leakage calculations and assumptions.

Table 12. Leakage adders in TDV and corresponding leakage rates

Leakage type	Leakage rate (% of natural gas consumption)	Leakage adder, 20-year GWP Included in 2022 TDV (% of CO2e emissions)
Oil & Gas Production and Processing	0.19%	5.09%
Natural Gas Transmission and Distribution	0.42%	10.94%
Residential behind-the-meter methane leakage	0.42%	10.89%

These leakage factors only apply to TDV where relevant. For example, residential natural gas consumption includes all three categories. For biogas that is assumed in the retail gas system, only leakage adders that are downstream of production are included; leaked biogas is assumed to be leaked as methane. Table 13 shows where the leakage adder is included.

Table 13. Leakage adders as they are applied to relevant fuel consumption

Leakage type	Res Natural Gas	Res Biogas	Non-Res Natural Gas	Non-Res Biogas	Electricity Generation
Oil & Gas Production and Processing	Included		Included		Included
Natural Gas Transmission and Distribution	Included	Included	Included	Included	Included
Residential behind-the-meter methane leakage	Included	Included			

Including these leakage adders, Figure 34 and Figure 35 show the CO2-equivalent emissions intensity of the retail gas blend. As a reference point, these figures show the emissions intensity of 100% natural gas with no leakage.

Figure 34 Carbon intensity of residential retail gas for 2022 TDV

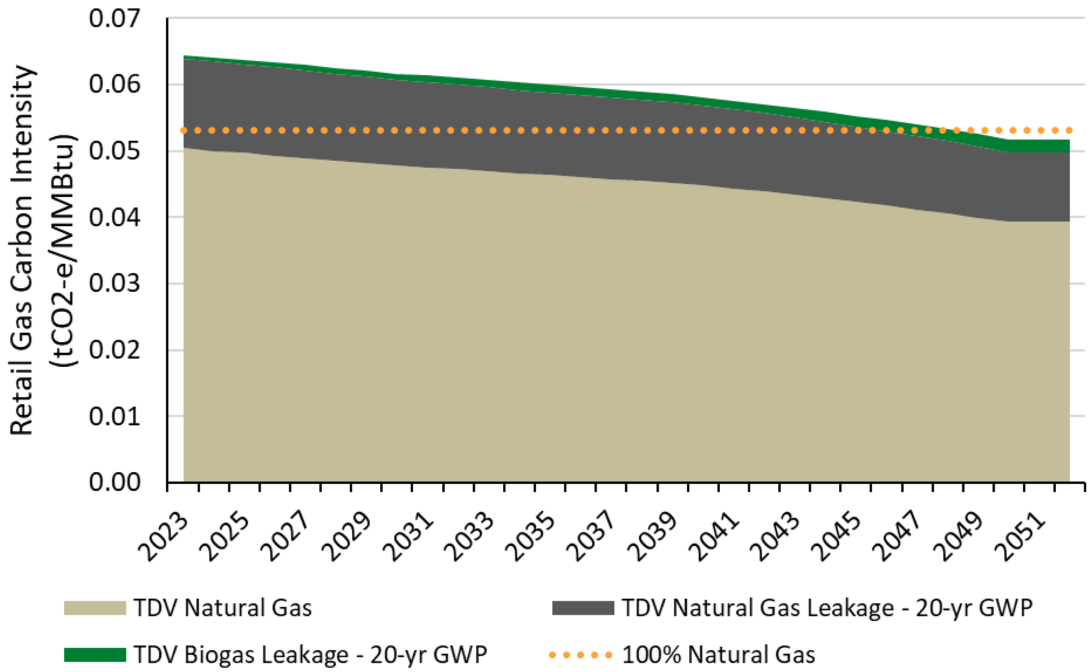
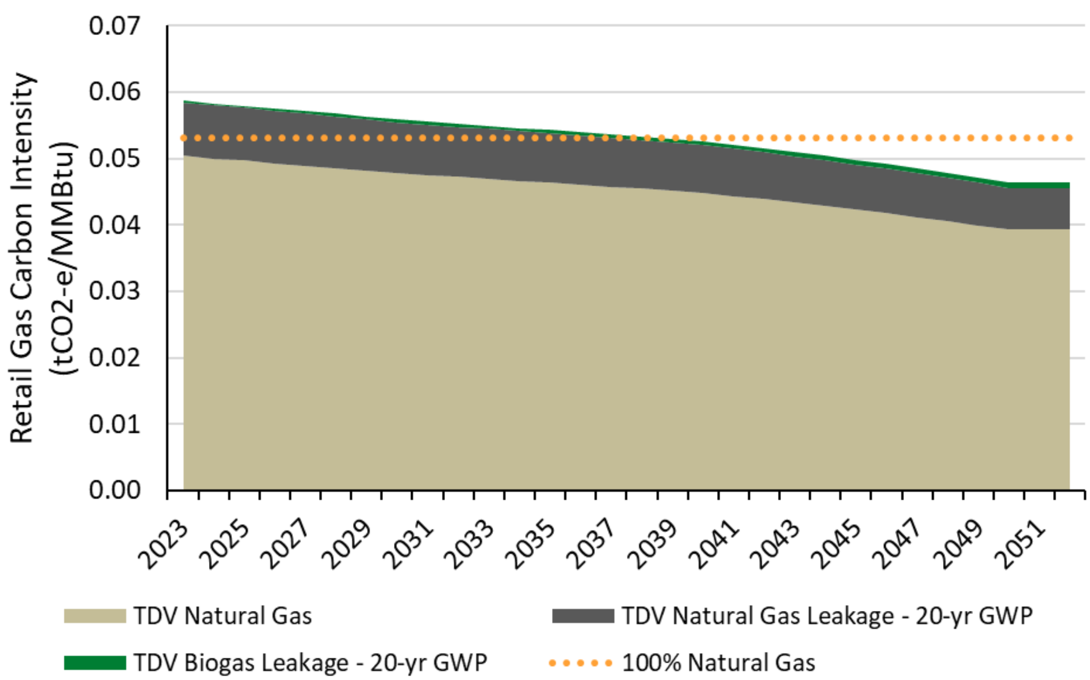


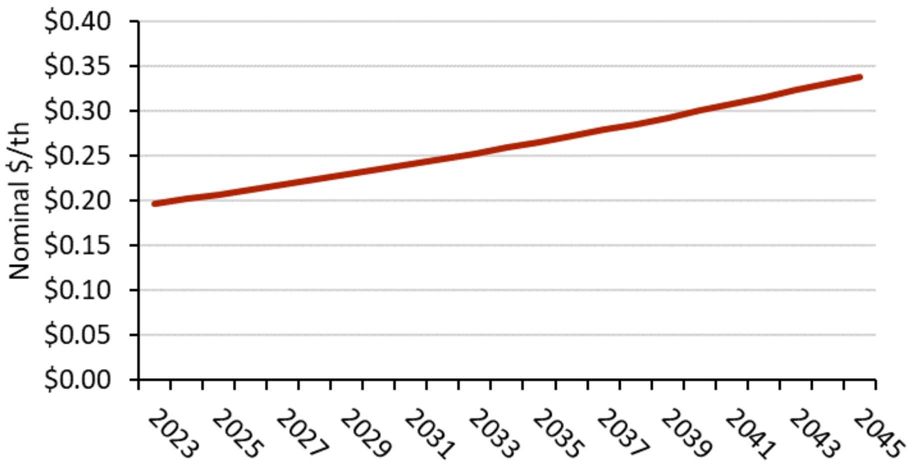
Figure 35 Carbon Intensity of non-residential retail gas for 2022 TDV



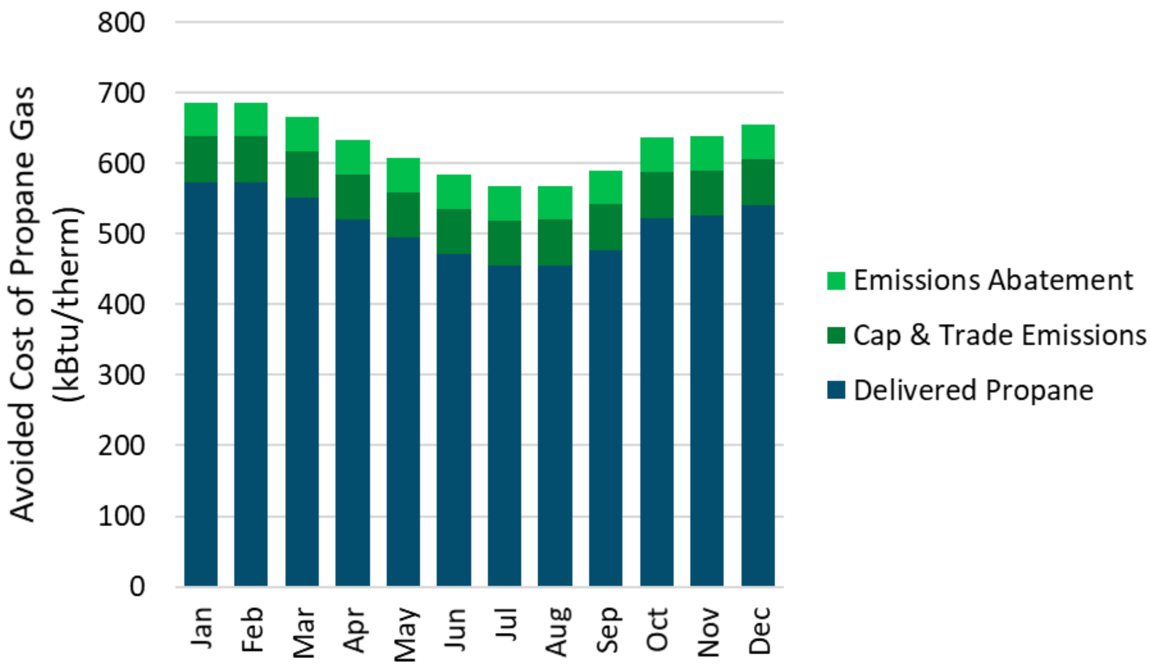
3.3.5 MARGINAL TRANSMISSION AND DISTRIBUTION COSTS

Natural gas distribution costs include the cost of building and maintaining a natural gas pipeline distribution network. These costs are based on historical gas transmission marginal costs, and allocated evenly across winter months, because demand for gas is highest in the winter.

Figure 36. 2022 TDV Natural gas transportation marginal costs



3.4 Propane 2022 TDV Inputs



The propane TDV is based on a long-run forecast of retail propane prices and the value of reduced emissions of carbon dioxide. Like natural gas TDV, propane TDV varies on a monthly basis, and is also more straight-forward than electricity TDV due to the more homogeneous nature of the retail propane market. Delivery charges are included in retail propane price forecasts, eliminating the need for a marginal T&D cost. The components are listed in Table 14.

Table 14. Components of Time Dependent Valuation for propane

	Component	Description
Marginal Propane Avoided Costs	Delivered Propane Cost	Estimate of monthly cost for delivered retail propane gas. Transportation and delivery charges are included in this price forecast
	Cap & Trade Emissions	The direct cost of carbon dioxide emissions (CO2) associated with end use propane consumption
	Economy-wide Emissions Abatement	The costs of abating combustion emissions beyond cap and trade market prices. Analogous to previous Carbon Externality. This cost is not included in retail rate forecasts, and therefore is added incrementally to TDV

Each component is estimated on a monthly or annual basis and forecasted into the future for 30 years. The monthly granularity of the avoided costs is obtained from several sources. Table 15Table 11 summarizes the methodology applied to each component to develop the monthly, or annual price shapes. The final propane TDV outputs, are formatted to be applied to hourly end-use consumption.

Table 15. Summary of methodology for propane TDV component forecasts

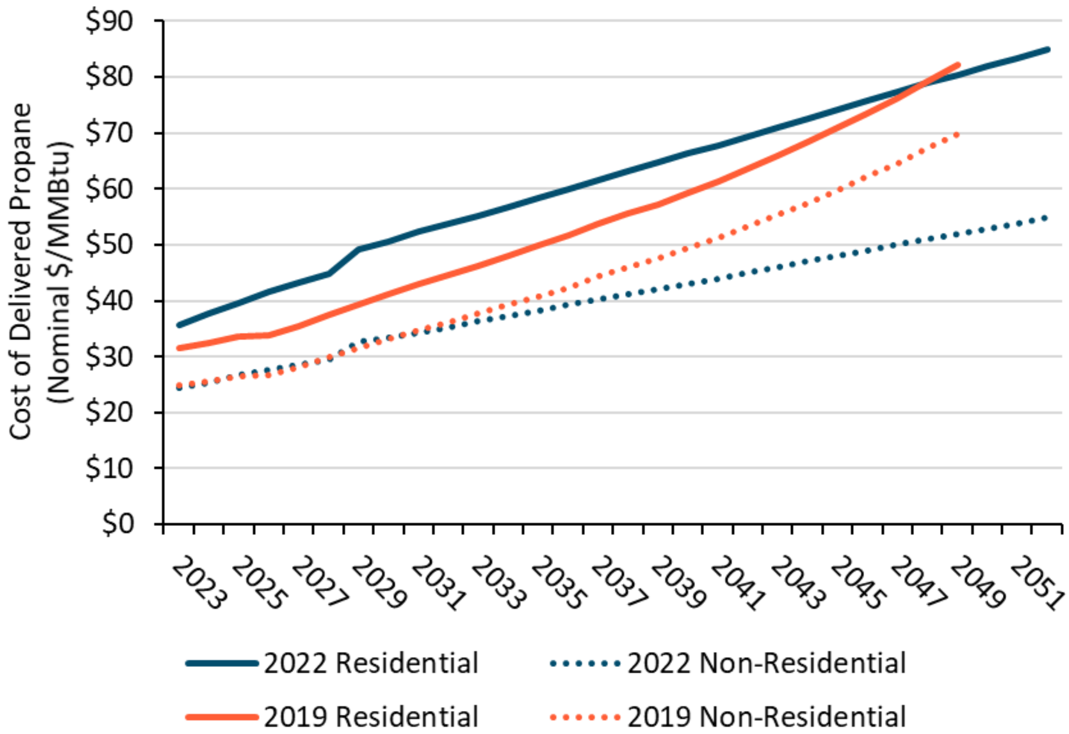
Component	Basis of Annual Forecast	Basis of Monthly Shape (if applicable)
Wholesale Commodity Cost	2019 EIA Annual Energy Outlook	Data from Western Propane Gas Association
Cap and Trade Emissions	CEC 2019 IEPR Cap and Trade price forecasts, applied to emissions intensity of propane gas	No monthly variation
Economy-wide Emissions Abatement	Cost of economy-wide marginal emissions reductions, beyond Cap & Trade	No monthly variation

3.4.1 DELIVERED PROPANE COSTS

The propane forecast is based on the U.S. Department of Energy (DOE) EIA 2019 Annual Energy Outlook Pacific Region reference case propane price forecast.[26] The EIA forecast for propane is through 2050, and a simple five-year trend is used for the years 2050 through 2052. Delivered propane costs for 2019 and 2022 TDVs are shown below in Figure 37. These price forecasts are for delivered propane, so any distribution related costs are embedded in this price forecast.

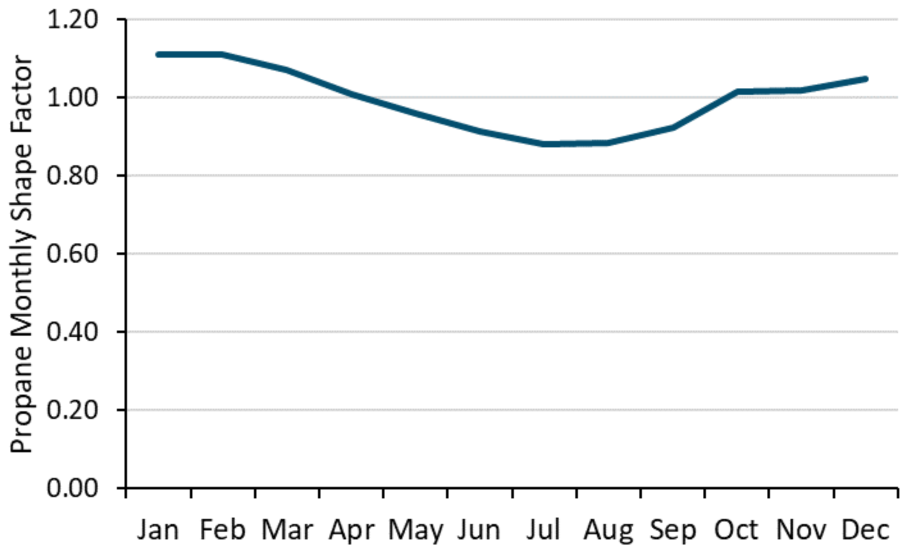
[26] 2019 EIA Annual Energy Outlook

Figure 37. Comparison of propane retail price forecasts in the 2019 and 2022 TDVs



The annual propane prices are also adjusted to reflect monthly variations in propane commodity costs. Those adjustment factors are carried over from the 2019 TDVs, and reflect actual propane data from the Western Propane Gas Association (WPGA), and are shown in Figure 38.

Figure 38. Monthly propane shape factors compared for 2022 TDVs



3.4.2 CAP AND TRADE EMISSIONS COST AND ECONOMY WIDE EMISSIONS ABATEMENT COST

Emission values are calculated based on the emissions rates of combusting propane in typical appliances. The CO_2 emissions rate for propane combustion is derived from the EIA estimates at 0.0631 metric tons/MMBtu[27].

In general, we apply the same methodology to the development of the propane TDVs as to the electricity and natural gas TDVs, in order to maintain as much parity between the fuel types as possible. In the case of greenhouse gas emissions, retail propane rates are assumed not to include CEC mid-IEPR carbon prices. Inclusion of a carbon price does not impact the shape of the propane TDVs but does increase the level of the propane TDVs. Following electricity and natural gas TDVs, the economy wide emissions abatement cost is included for propane as well.

[27] EIA https://www.eia.gov/tools/faqs/faq.php?id=73&t=11

4 Results

4.1 Electricity TDV

The hourly average results for electricity TDV are shown below. Each plot shows the average over the year, by hour of the day (Pacific Standard Time). TDV results show the present value of costs across the assumed lifetime of the building (30 years for residential, and 15 or 30 years for non-residential) and are converted to units of kBtu/kWh, as described in Section 5.1. Full hourly results can be viewed in the Dashboard tab of TDV_2022_Update_Model_20200528.xlsx.

4.1.1 COMPARISON TO PREVIOUS TDV

Comparing 2022 Electricity TDV to 2019 and 2016 electricity TDV, the updated results for the 2022 code cycle show a distinct mid-day period with low energy prices that corresponds with an over-supply of solar generation. Also notable in 2022 is a late morning bump driven by the capacity cost component's eventual shift to cold winter mornings. The T&D peak shifts later in the day, due to increasing levels of rooftop PV generation. Figure 39 and Figure 40 show the comparison of residential and non-residential electricity TDV compared to the overall 2019 and 2016 electricity TDV. Overall, 2022 electricity TDV has not increased significantly compared to 2019; this is driven by decreased forecasts for retail electricity rates from the most recent IEPR forecast.

Figure 39. Climate Zone 12 (Residential 30 yr) 2022 TDV with comparison to 2019 and 2016 TDV

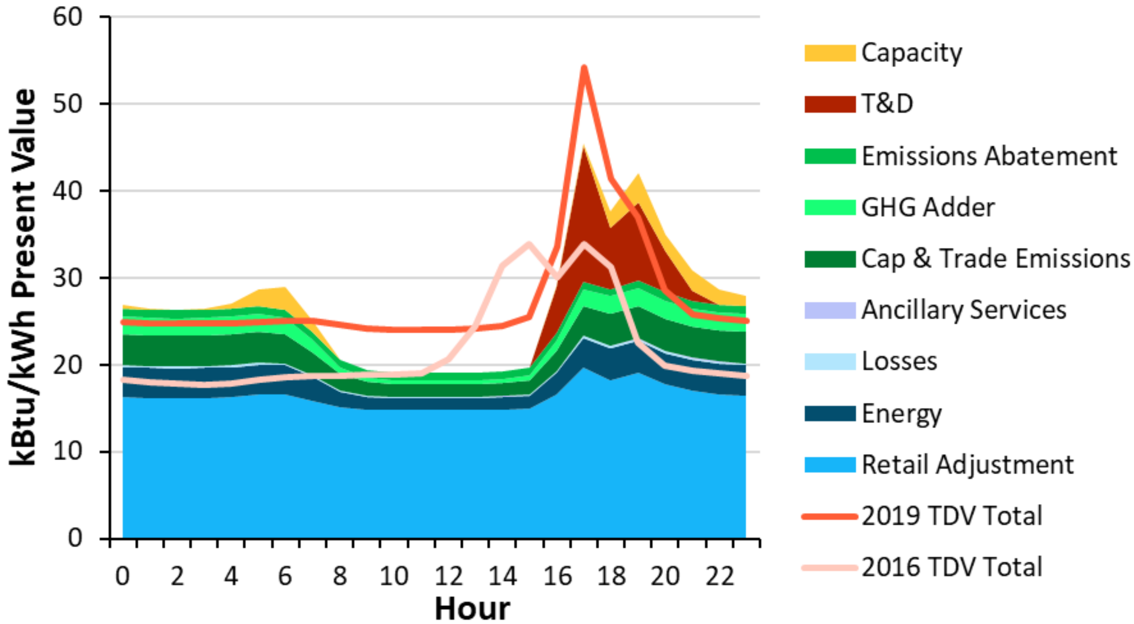
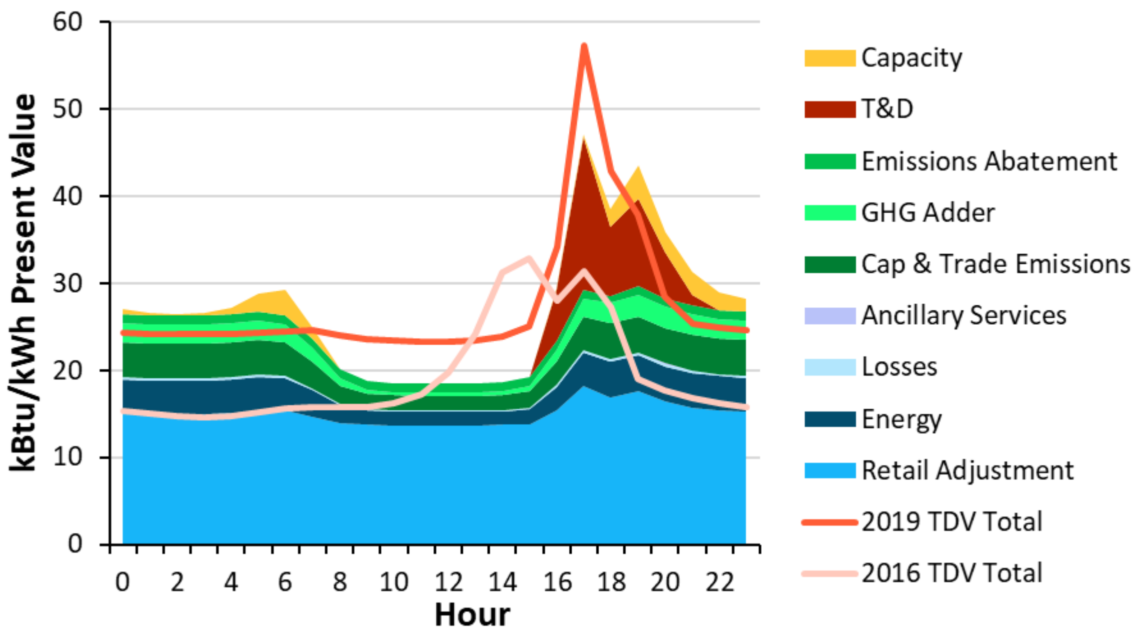


Figure 40. Non-Residential 2022 Electricity TDV for CZ12, compared to 2019 and 2016 TDV



4.1.2 RESIDENTIAL ELECTRICITY TDV RESULTS BY CLIMATE ZONE

To demonstrate the difference in electricity TDV shape between climate zone, this section of results displays residential TDV for all 16 climate zones; the difference in hourly shape between climate zones is largely determined by differences in T&D peak hours. Non-residential TDV has a similar hourly shape to residential TDV for a given climate zone, with the exception that non-residential TDV has a smaller retail rate adjustment, due to retail rate forecasts, which are lower for non-residential customers. The difference in retail rates is reduced by $/kBtu conversion discussed in section 5.1.

Figure 41: Climate Zone 1 Residential (30 yr)

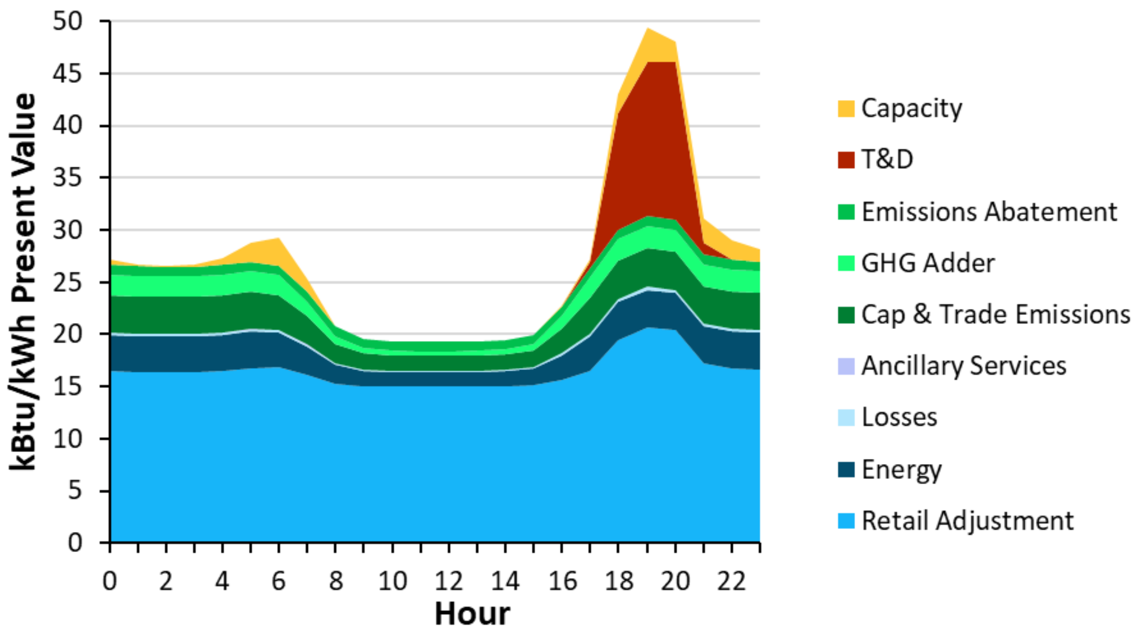


Figure 42: Climate Zone 2 Residential (30 yr)

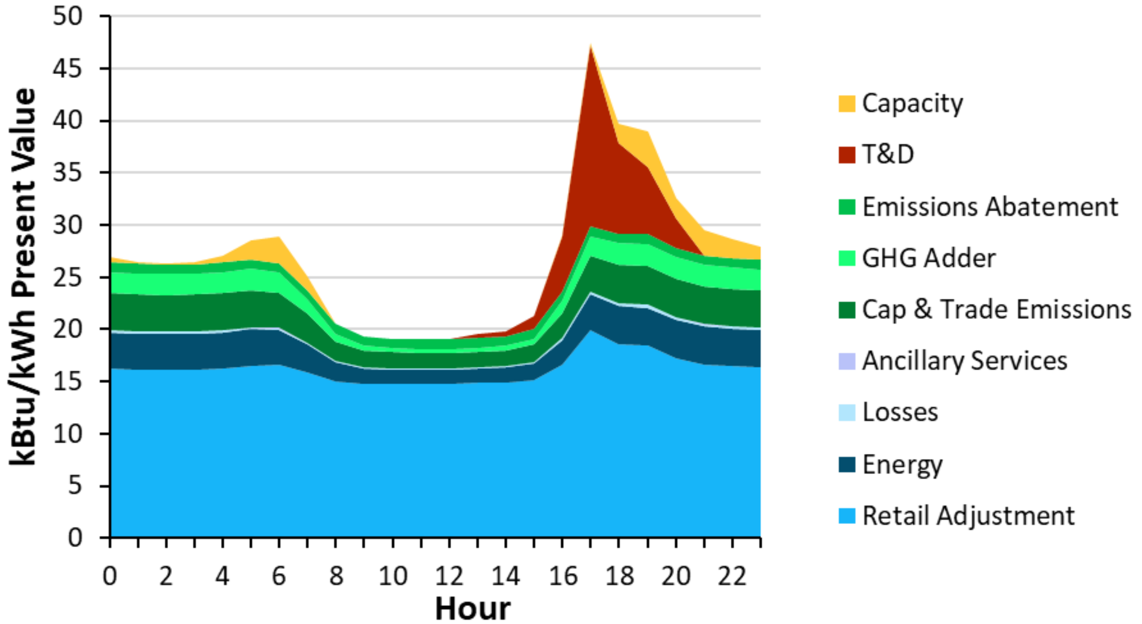


Figure 43: Climate Zone 3 Residential (30 yr)

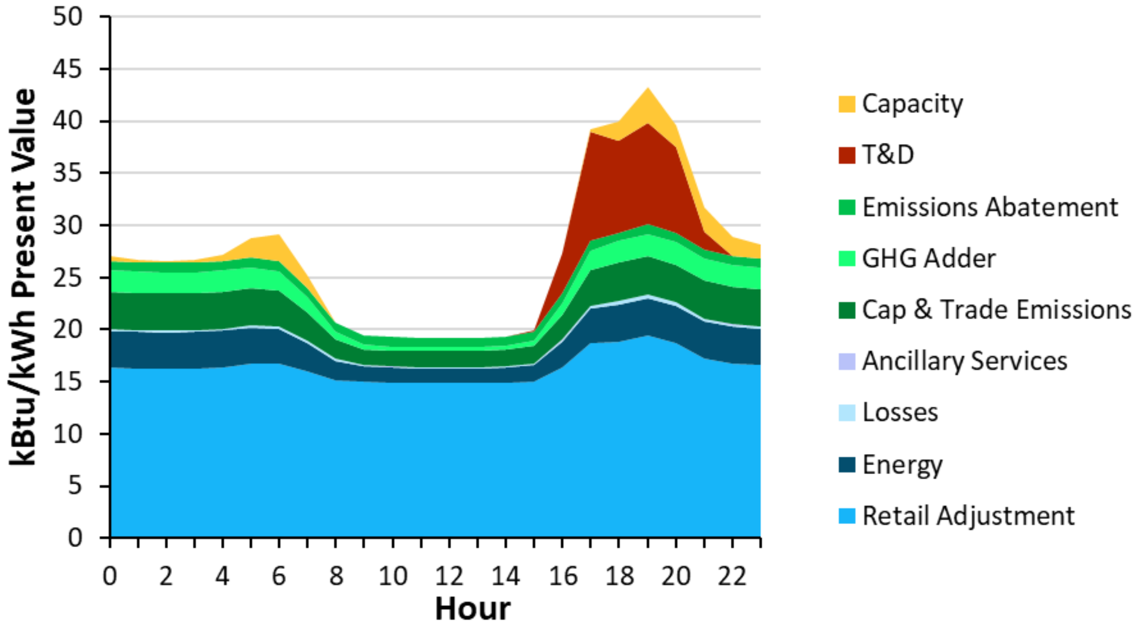


Figure 44: Climate Zone 4 Residential (30 yr)

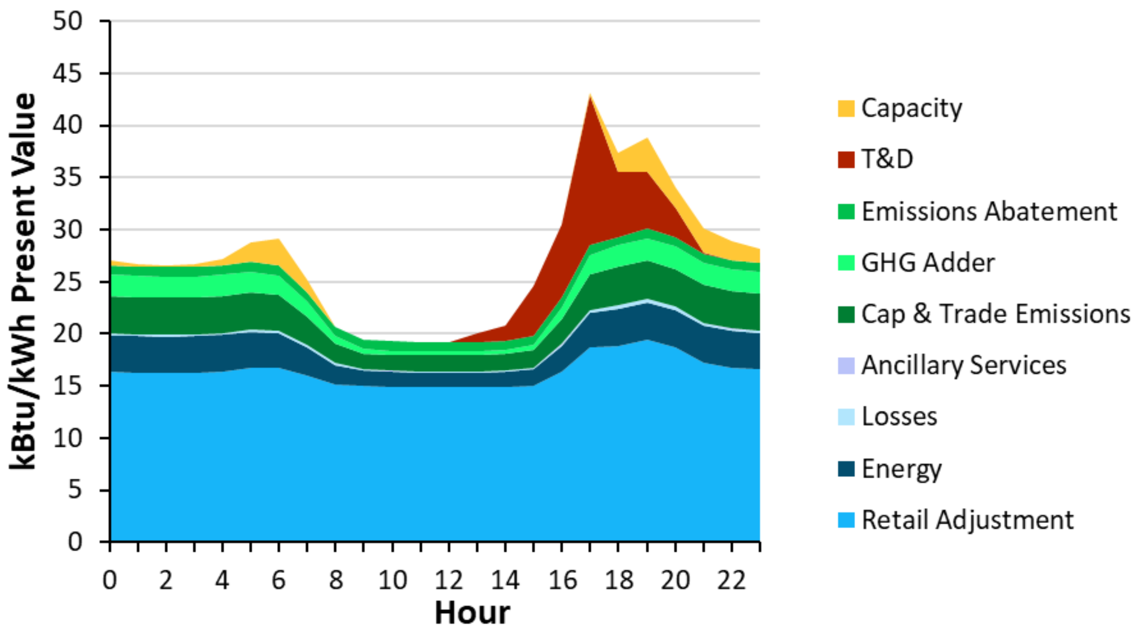


Figure 45: Climate Zone 5 Residential (30 yr)

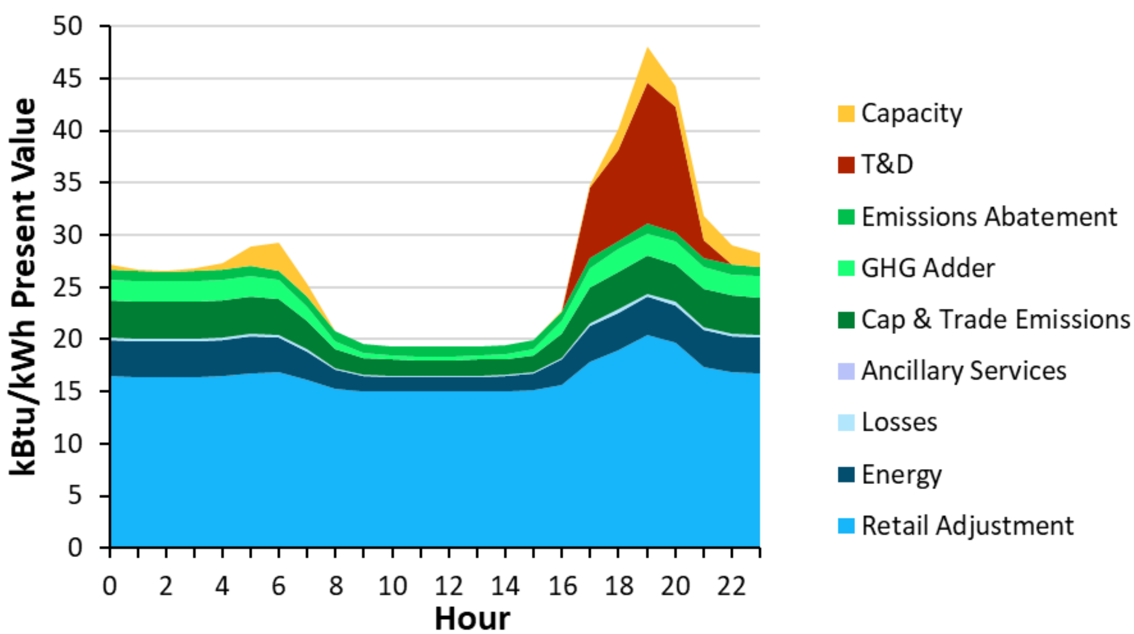


Figure 46: Climate Zone 6 Residential (30 yr)

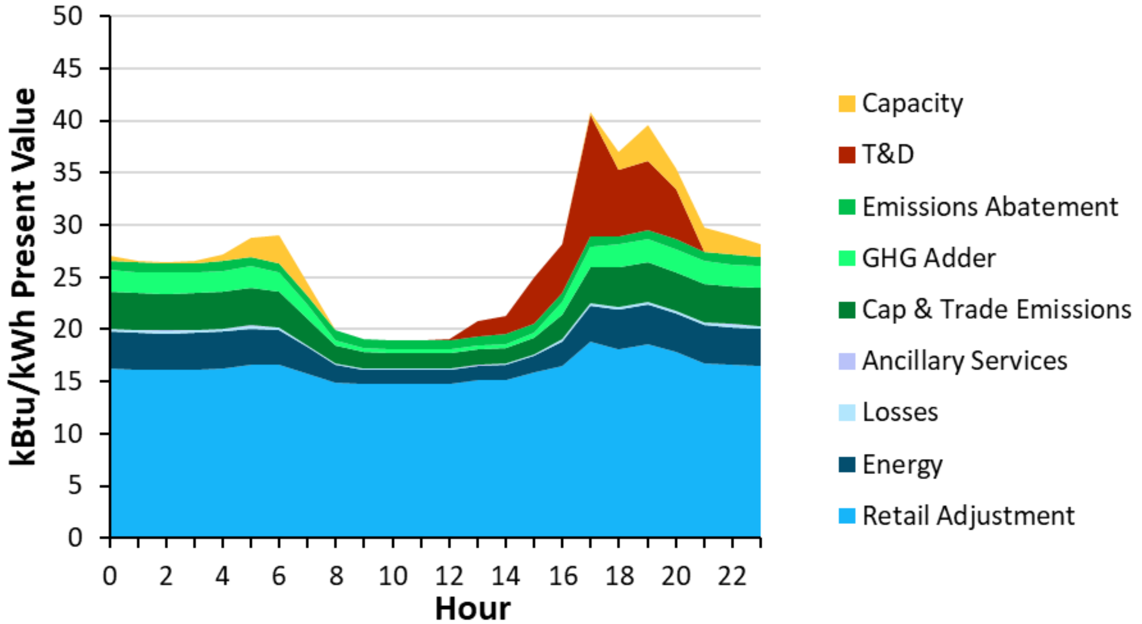


Figure 47: Climate Zone 7 Residential (30 yr)

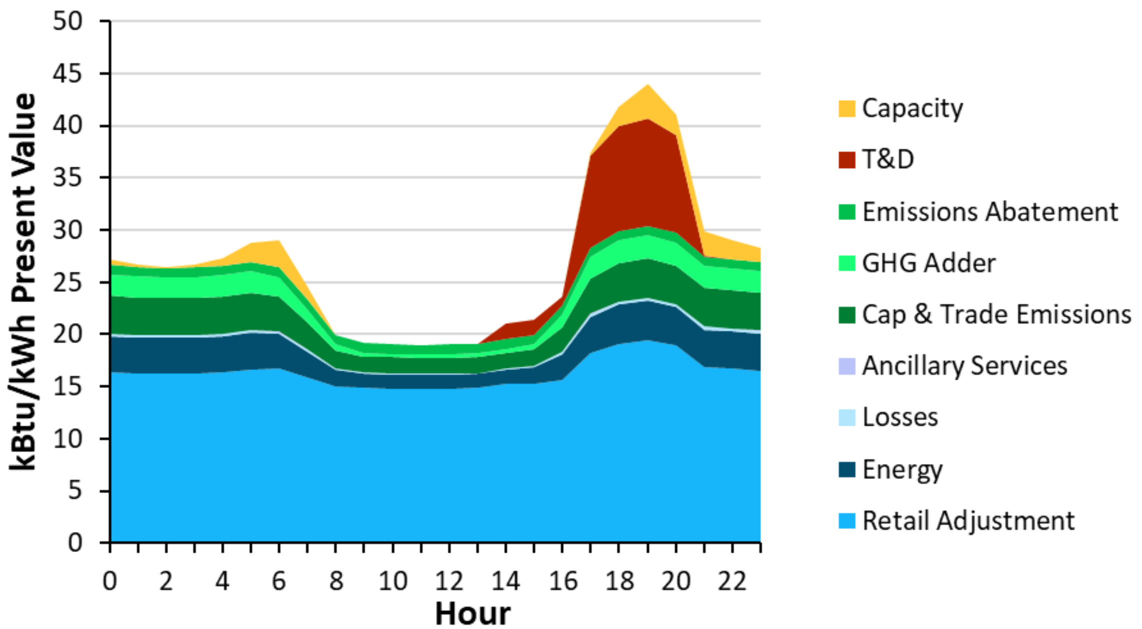


Figure 48: Climate Zone 8 Residential (30 yr)

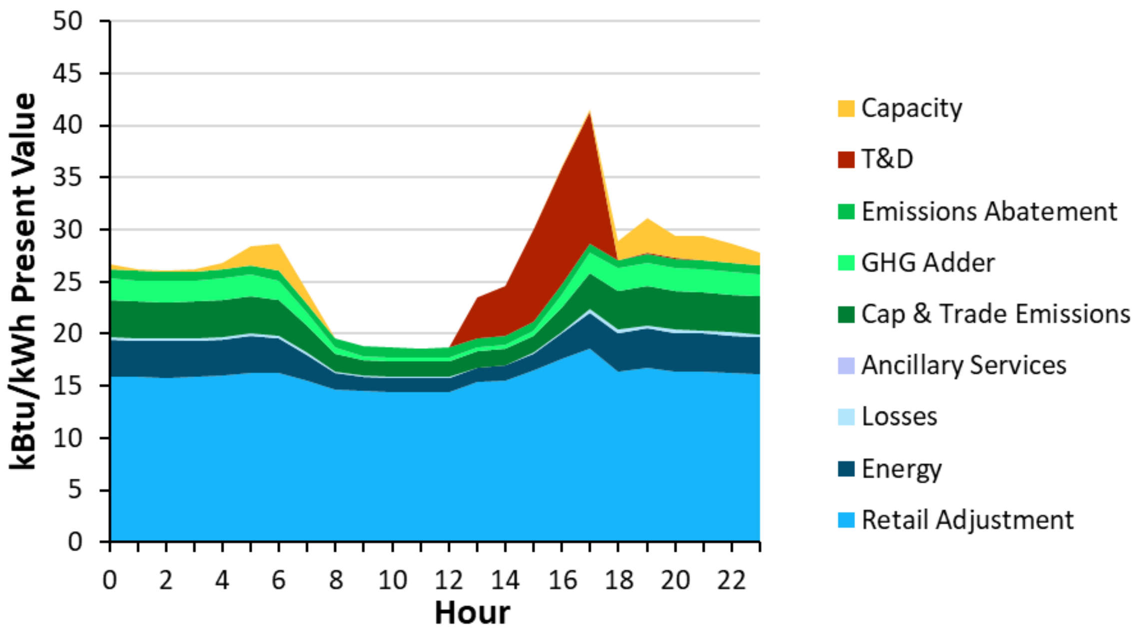


Figure 49: Climate Zone 9 Residential (30 yr)

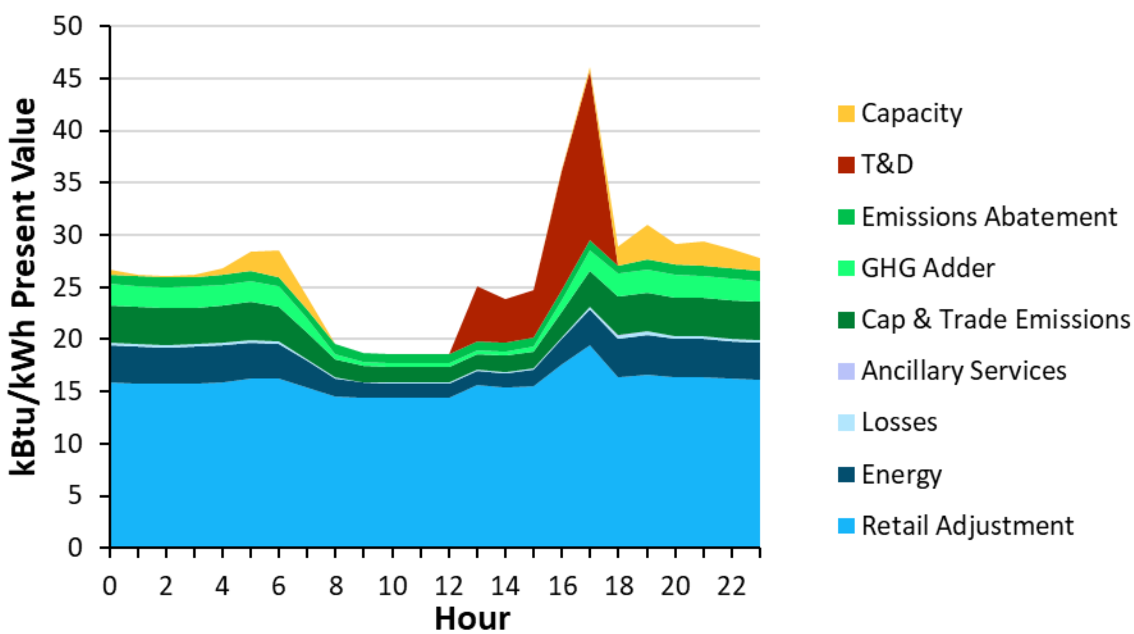


Figure 50: Climate Zone 10 Residential (30 yr)

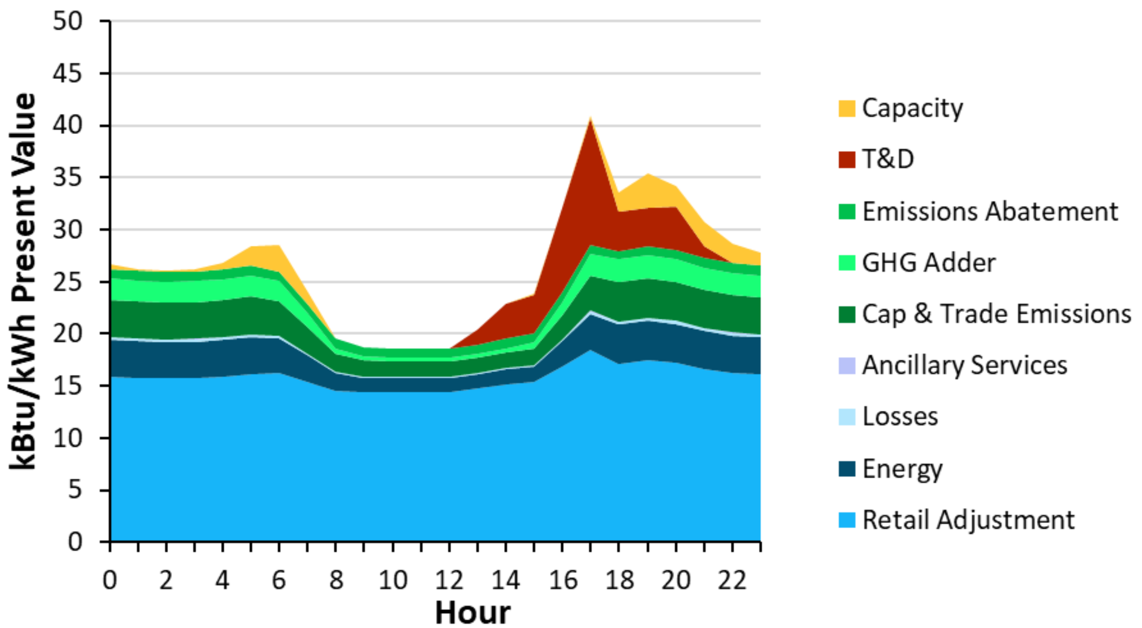


Figure 51: Climate Zone 11 Residential (30 yr)

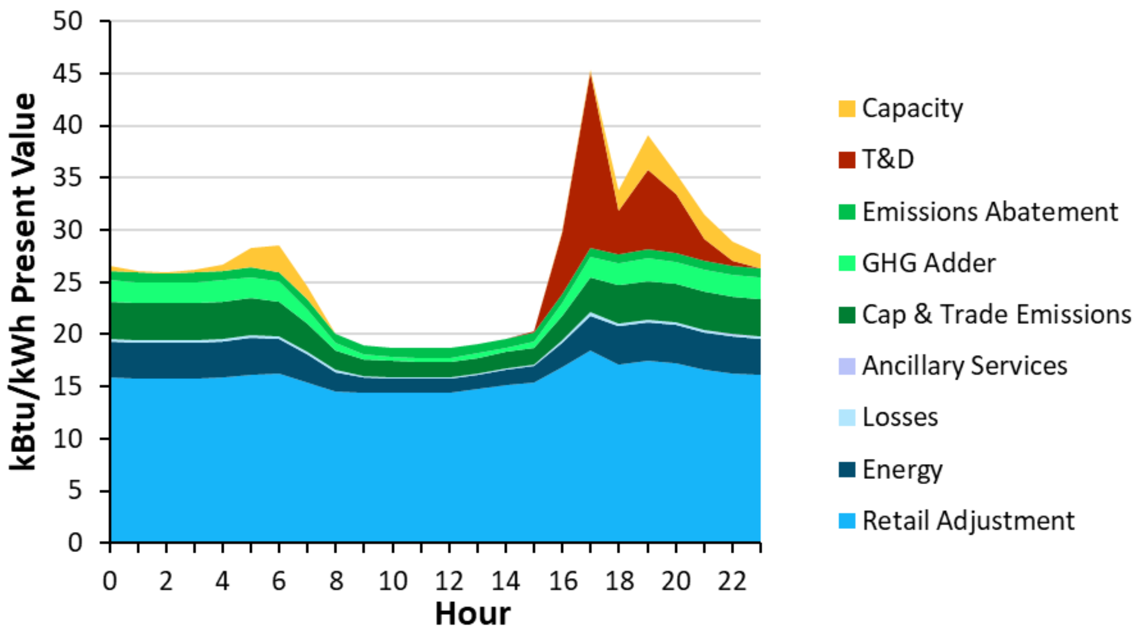


Figure 52: Climate Zone 12 Residential (30 yr)

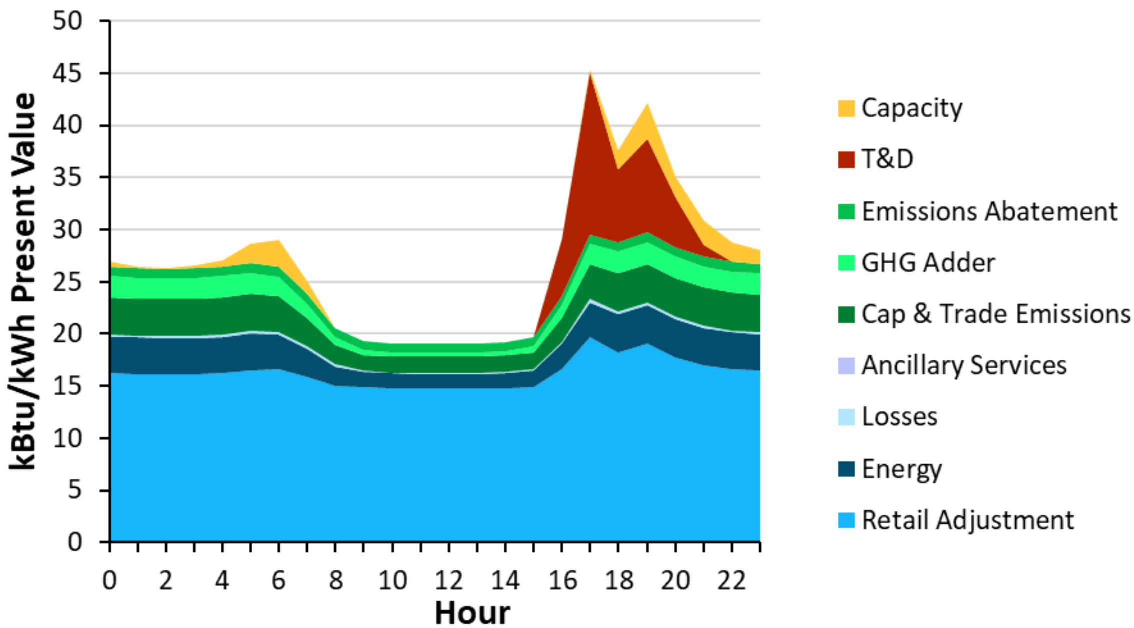


Figure 53: Climate Zone 13 Residential (30 yr)

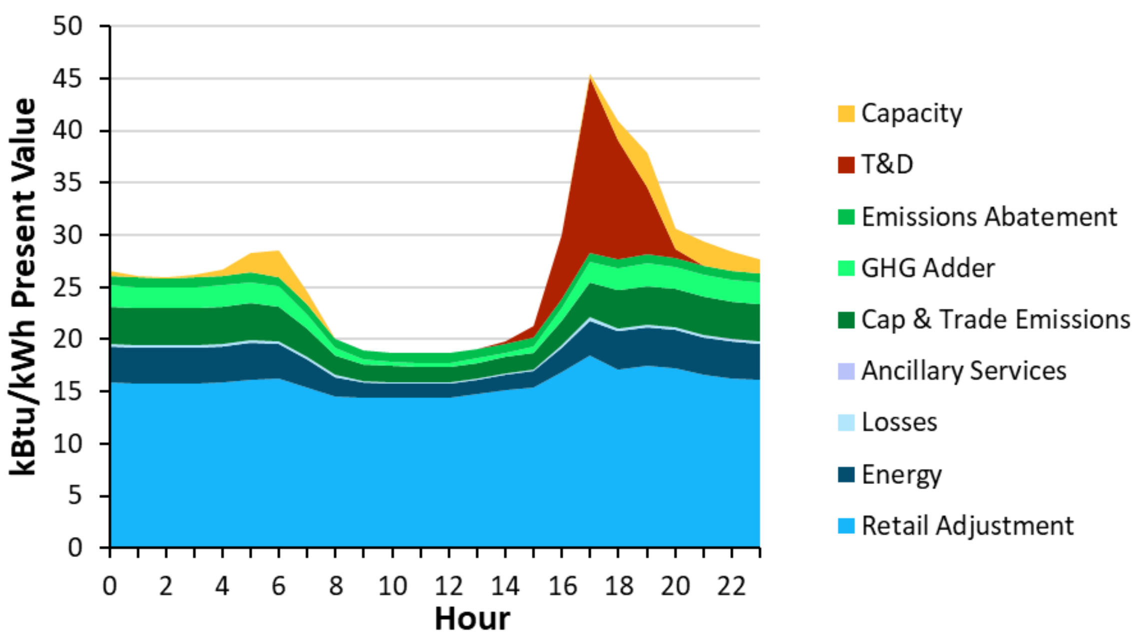


Figure 54: Climate Zone 14 Residential (30 yr)

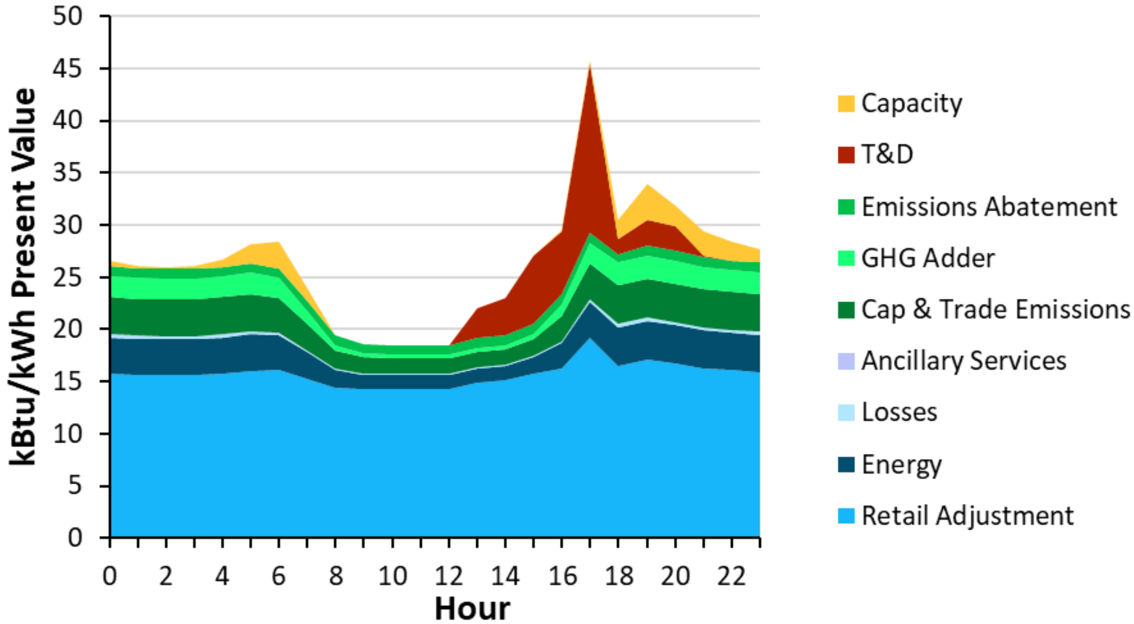


Figure 55: Climate Zone 15 Residential (30 yr)

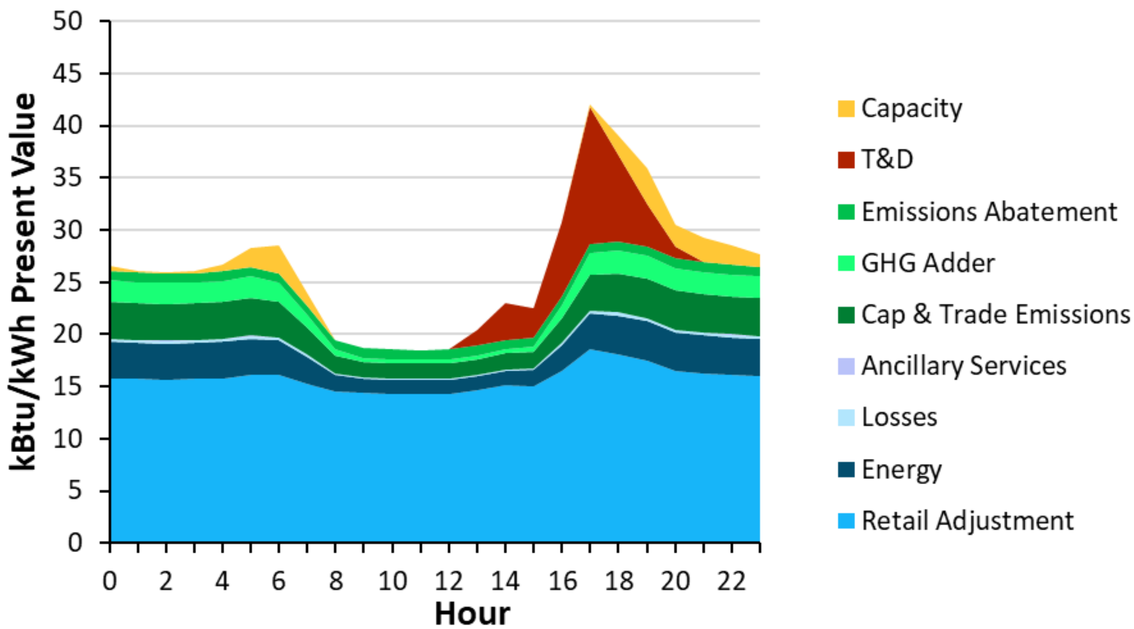
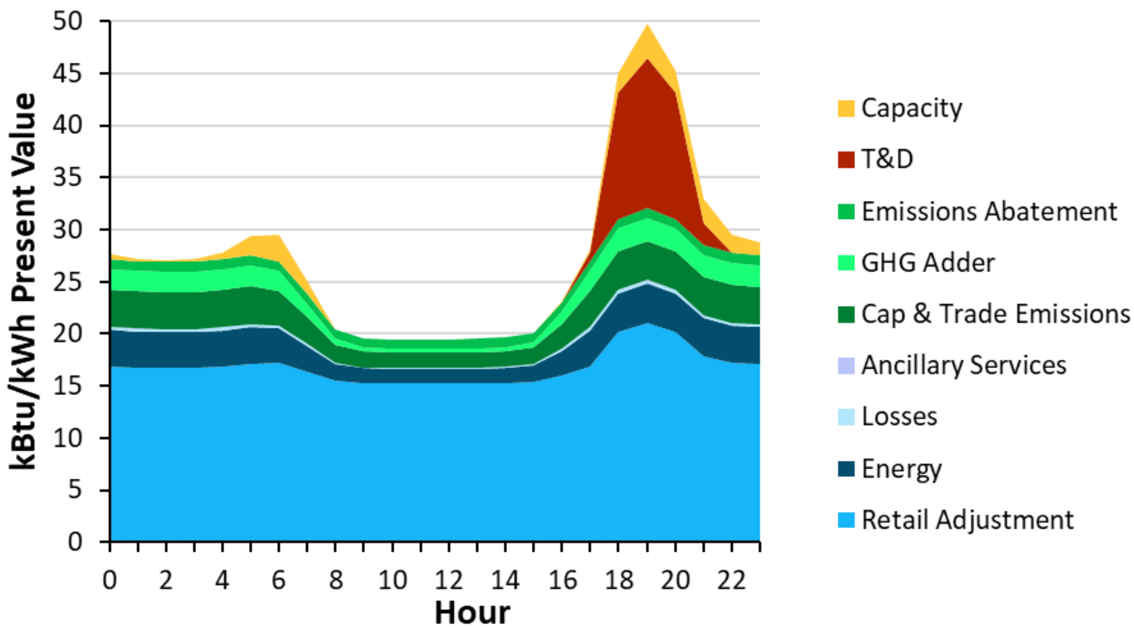


Figure 56: Climate Zone 16 Residential (30 yr)



4.2 Natural Gas

The monthly average of 2022 natural gas TDV, broken down by cost component are shown in the charts below. To demonstrate the impact of updates in 2022 TDV, Figure 57 and Figure 58 compare 2022 results to 2019 and 2016 total natural gas TDV. As seen in these plots, the 2022 code cycle update shows a significant increase compared to previous code cycles. This is driven by the new retail rate forecast, which includes more expensive biogas and hydrogen, relatively increased fixed costs for maintaining the natural gas distribution system, and the new emissions abatement cost component. The retail rate increases due to decreased natural gas throughput in the gas has a less significant impact for non-residential retail gas customers, so the relative difference between 2022 and 2019 TDV is smaller for non-residential TDV.

Results for different climate zones are not included below, as there is little difference between climate zones for natural gas TDV. TDV results show the present value of costs across the assumed lifetime of the building (30 years for residential, and 15 or 30 years for non-residential) and are converted to units of kBtu/th, as described in Section 5.1. Full hourly results can be viewed in the Dashboard tab of TDV_2022_Update_Model_20200528.xlsx.

Figure 57. 2022 Residential Natural Gas TDVs by month and component for CZ 12, compared to 2019 and 2016 TDV

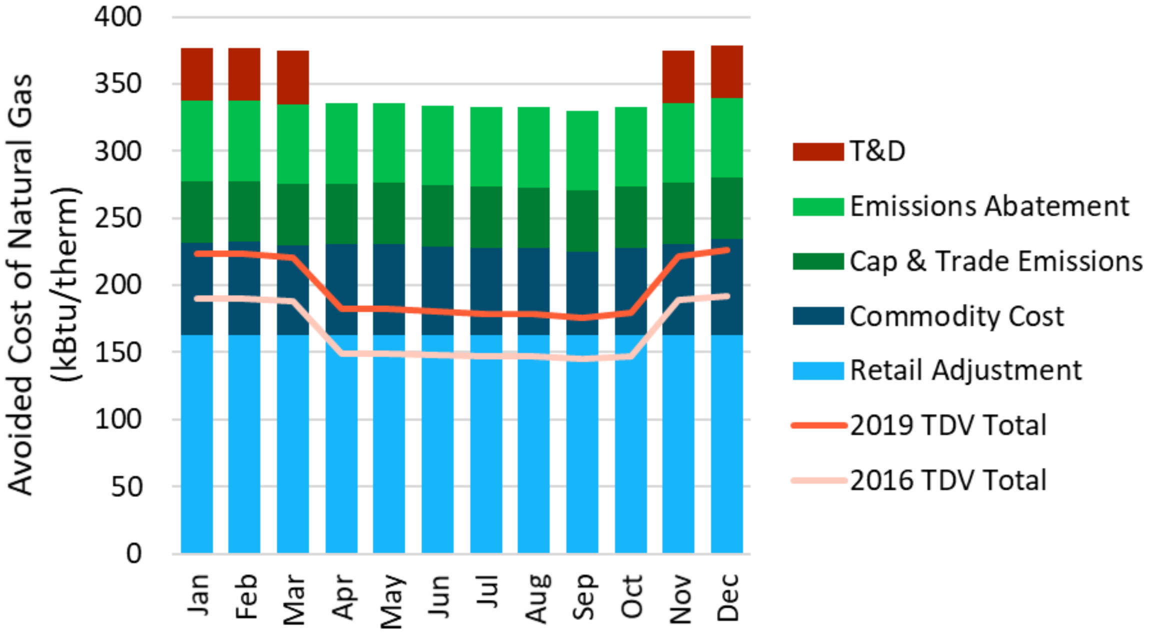
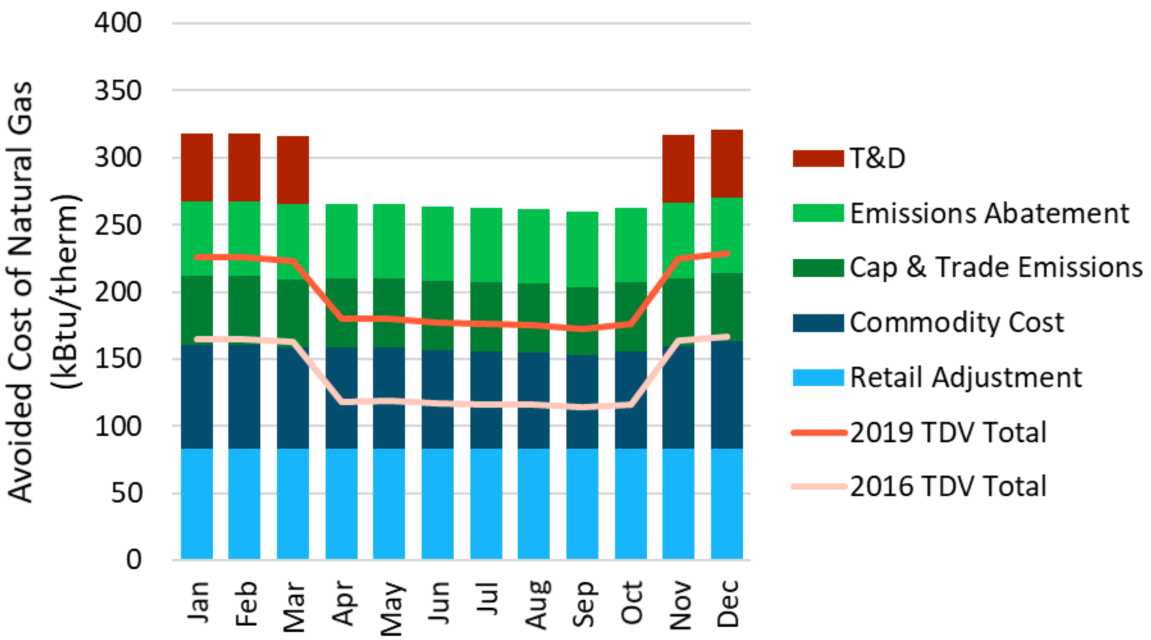


Figure 58. 30-year Non-Residential Natural Gas TDVs by month and component for CZ 12



4.3 Propane

The figures below show residential and non-residential (30-yr) propane TDV, by month, and broken down by cost component. 2022 propane TDV is higher than 2019 and 2016 propane TDV due to the updated annual forecast from the EIA's 2019 Annual Energy Outlook, and the general monthly shape is consistent with previous code cycles. TDV results show the present value of costs across the assumed lifetime of the building (30 years for residential, and 15 or 30 years for non-residential) and are converted to units of kBtu/th, as described in Section 5.1. Full hourly results can be viewed in the Dashboard tab of TDV_2022_Update_Model_20200528.xlsx.

Figure 59. Residential Propane TDVs by month and component for CZ 12

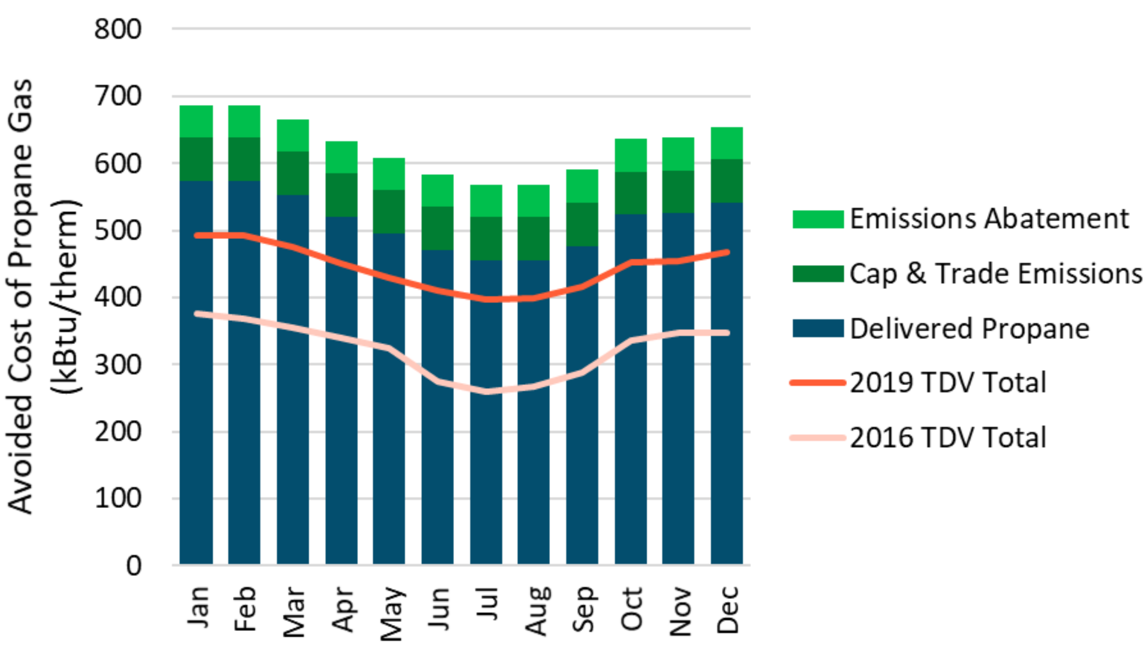
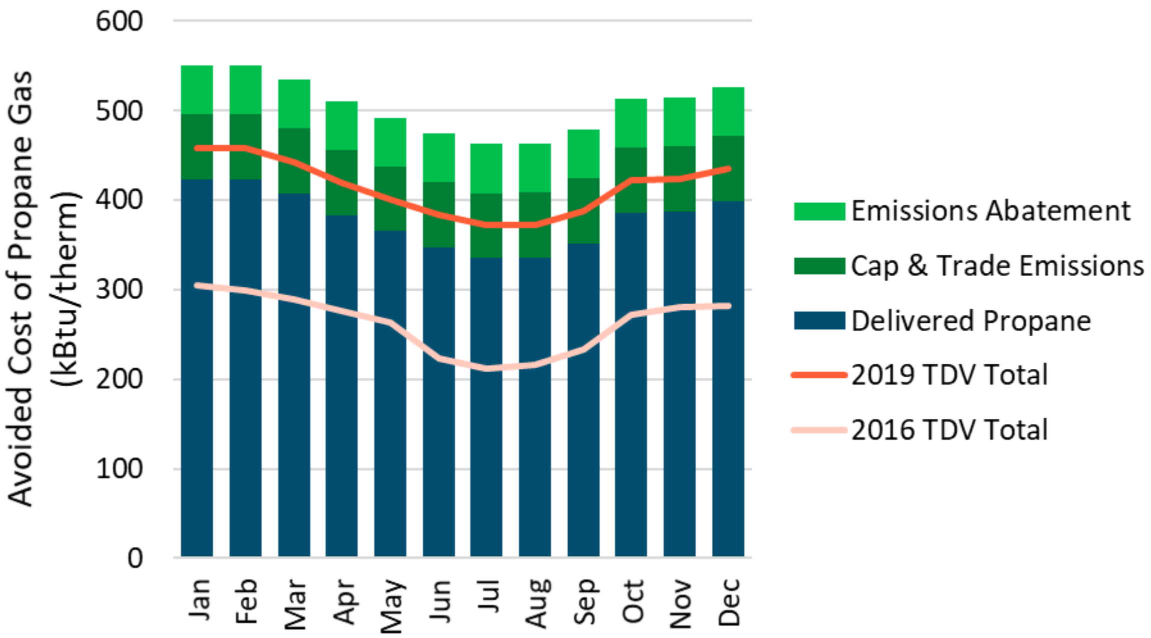


Figure 60. Non-Residential (30-yr) Propane TDV for CZ 12



5 TDV Lifecycle Methodology

5.1 Calculating Net Present Value TDVs

The Warren-Alquist Act, requires the Energy Commission to develop and maintain energy efficiency standards that are "*… cost effective, when taken in their entirety, and when amortized over the economic life of the structure when compared with historic practice*".[28] This section describes the life-cycle cost (LCC) methodology to be used to evaluate proposed changes for the 2022 Building Energy Efficiency Standards. Cost effectiveness analysis is needed only for mandatory measures and prescriptive requirements. It is not required for compliance options.

The approach for converting annual hourly avoided costs and retail adjustments into TDV values in the 2022 TDV cycle is largely the same as the approach taken for 2019 but updated with more current projections of energy costs. To calculate the "lifecycle" value of energy savings, we calculate the net present value (NPV) of each hour's energy cost over a 15-year and 30-year nonresidential analysis period and over a 30-year residential analysis period. The NPV is calculated by applying a 3% real (inflation adjusted) discount rate, inflation is assumed to be 2% per year. Next, the NPV TDV is converted from a cost per unit energy ($/kWh) to an energy only unit (kWh/Btu). The TDV values are presented in terms of energy units for the following reasons:

+ Describing TDV in terms of energy units is consistent with past performance method compliance methods. The intent is to minimize the impact of TDV on practitioners; TDV energy units are simply substituted for source energy, which was the original unit of analysis.
+ Converting the TDV cost units to energy units makes it less likely that someone might mistakenly interpret TDV savings as an estimate of the dollar savings that an individual building owner might see by implementing the Tile 24 standard. Given that local utility rates vary over time and across regions and given that actual building operating practices can vary significantly, it was not

[28] Warren Alquist Act, Public Resources Code Section 25402.

desirable to imply that the TDV savings are the same as the dollar savings that any single building owner might realize.

TDVs are converted to energy units using the same NPV cost in real dollars of natural gas as was applied in the 2008, 2013, 2016 and 2019 standards. By using the same conversion factor (in real dollars) in each Title 24 update, the relative stringency of the TDVs can be more easily compared across periods. This is appropriate because the adjustment factors are merely an accounting convention and the underlying TDVs already reflect updates for energy prices, inflation etc. An increase in natural gas price forecasts between updates would, as expected, result in an increase in the TDVs. However, note that in the adjustment factor formula below that $/kBtu natural gas prices are in the denominator. Thus, reflecting an *increase* in natural gas prices would result in a *decrease* in the adjustment factor- effectively negating the expected impact on $/kBtu TDV.

The conversion factor (based on the 2005 forecasted NPV gas cost) is $0.173/kBtu for 30-year residential TDVs (Table 4). Multiplying the TDV expressed in energy units by this $/kBtu factor yields NPV $/kWh and $/therm TDVs (See Table 5). The non-residential conversion factors for 30-year and 15-year measures are $0.154/kBtu and $0.089/kBtu respectively.

For evaluating the cost-effectiveness of new measures, the annual TDV energy savings can be multiplied by the following standardized factors, shown in Table 16 in NPV $/kBtu.

Table 16. TDV Conversion Factors, NPV $/kBtu

	NPV (30-year)	NPV (15-year)
Low-Rise Residential	$0.1732	n.a.
Nonresidential & High-rise Residential	$0.1540	$0.0890

The equation below, by example, provides the units analysis for electricity TDV to move from the $/kWh to TDV kBtu/kWh. The “TDV energy factors” are the source energy values referenced in the Title 24 regulations and used in the compliance calculation process to produce a TDV kBtu energy use estimate for a modeled building:

$$\text{TDV Energy Factors} = \frac{\text{TDV Dollars}\,[\text{NPV\$/kWh}]}{\text{Forecasted NG Cost}\,[\text{NPV\$/kBtu}]} = \frac{\frac{\text{NPV\$(hr)}}{\text{kWh}}}{\frac{\text{NPV\$}}{\text{kBtu}}} = \frac{\text{kBtu(hr)}}{\text{kWh}}\ or\ \frac{\text{TDV kBtu}}{\text{kWh}}$$

Just like TDV dollar values, the TDV energy factors vary for each hour of the year. To evaluate the TDV energy cost or benefit of a measure, each hour's electricity savings is multiplied by that hour's TDV energy value. As shown below, this yields an annual savings figure in terms of TDV kBtu.

$$\text{Annual TDV Savings}\,[\text{TDV kBtu}] = \sum_{h=1}^{8,760} \text{Energy Savings}_h\,[\text{kWh}] \times \text{TDV Energy Factor}_h \left[\frac{\text{TDV kBtu}}{\text{kWh}}\right]$$

For evaluating the cost-effectiveness of new measures, the annual TDV kBtu energy savings calculated by an energy model can be multiplied by the $/kBtu adjustment factors listed in Table 16.

The resulting average TDV values (unweighted) across all climate zones and hours of the year are shown in Table 17 for the 2008, 2013, 2016, 2019, and 2022 TDV Update cycles.

Table 17. Statewide average TDV factors for Natural Gas and Electricity, 2008 - 2022

Time Period	2008	2013	2016	2019	2022
30 Year Residential					
Natural Gas (NPV$/Therm)	$24.32	$27.68	$28.64	$34.25	$60.86
Electricity (NPV $/kWh)	$2.33	$3.62	$3.73	$4.74	$4.66
15 Year Non-Residential					
Natural Gas (NPV$/Therm)	$12.72	$14.59	$12.75	$16.00	$22.60
Electricity (NPV $/kWh)	$1.63	$1.85	$1.83	$2.45	$2.51
30 Year Non-Residential					
Natural Gas (NPV$/Therm)	$23.97	$25.96	$23.62	$30.44	$44.10
Electricity (NPV $/kWh)	$2.66	$3.36	$3.19	$4.24	$4.18

TDVs for 2008 are expressed in $2008, 2013 are in $2011, 2016 are in $2017, 2019 are in $2020, 2022 are in $2023

5.2 Calculating Nominal TDVs

While not used in cost-effectiveness calculations, economic impact in nominal dollars is also required for the California Department of Finance's Fiscal and Economic Impact Report (Form 399). The TDV spreadsheet model is capable of generating hourly nominal dollar values for TDV in each year, however this amount of data is cumbersome for reporting purposes, and can be generalized into conversion factors that can be applied to the present value dollar results described in Section 5.1. These generalized conversion factors are calculated by comparing state average nominal dollar results in each year to the present value TDV factors. Each cost component within electricity, gas, or propane TDV increases year over year at different rates, which prevents a universal conversion factor between lifetime present value and nominal dollars. Unique conversion factors are required for each combination of Building Type (Res (30-yr), Non-Res (15-yr), and Non-Res (30-yr)) and Fuel Type (Electricity, Natural Gas, and Propane).

Reporting on nominal dollars may be required over different timescales, typically: Year 1 nominal impact, lifetime nominal impact, or for other intermediate specific years. To calculate generalized conversion factors for this, first, "NPV to Year 1 Nominal Multiplier" is calculated based on the ratio of the statewide average of Year 1 (2023) nominal value TDV to the statewide average of lifetime present value TDV, as calculated from the factors in Table 16. To calculate Year 1 Nominal value, for example, the "NPV to Year 1 Nominal Multiplier" from Table 18 is used as follows:

$$Year\ 1\ Nominal\ Value = NPV\ to\ Year\ 1\ Nominal\ Multiplier * NPV_{TDV}$$

Next, to estimate lifetime nominal value, or nominal value for a specific year, the Annual Growth Rate is calculated by taking the compound annual growth rate of the nominal values over the lifetime of the building type. The equation for annual growth is as follows:

$$Annual\ Growth\ Rate = \left(\frac{Average\ Nominal\ Value_{final}}{Average\ Nominal\ Value_{2023}}\right)^{\frac{1}{t}} - 1$$

Where $Average\ Nominal\ Value_{final}$ is the statewide annual average of nominal hourly values for year 2052 (30 year lifetime) or 2037 (15 year lifetime), $Average\ Nominal\ Value_{2023}$ is the statewide annual average of 2023 (Year 1) nominal hourly values, and t is the building lifetime in years (30 years or 15 years).

The Annual Growth Rate is used to calculate the "Year 1 Nominal to Lifetime Nominal Multiplier" with the following equation for the sum of a geometric series:

$$Year\ 1\ Nominal\ to\ Lifetime\ Nominal\ Multiplier = \frac{1 - (1 + Annual\ Growth\ Rate)^t}{1 - (1 + Annual\ Growth\ Rate)}$$

Putting these two conversion factors into practice, the lifetime nominal value can be calculated with the following equation:

$$Lifetime\ Nominal\ Value = (Year\ 1\ Nominal\ to\ Lifetime\ Nominal\ Multipler) * (Year\ 1\ Nominal\ Value)$$

Similarly, the Nominal value for intermediate year, *n*, can be calculated with the following equation:

$$Nominal\ Value_n = Year\ 1\ Nominal\ Value * (1 + Annual\ Growth\ Rate)^n$$

Table 18. Conversion Factors to calculate nominal dollar impact of TDV, based on Net Present Value from Section 5.1

Building Type	Fuel	NPV to Year 1 Nominal Multiplier	Annual Growth Rate	Year 1 Nominal to Lifetime Nominal Multiplier
Res (30-yr)	Electricity	0.0477	2.38%	43.06
	Natural Gas	0.0357	4.11%	57.09
	Propane	0.0389	3.27%	49.70
Non-Res (15-yr)	Electricity	0.0803	2.21%	17.56
	Natural Gas	0.0642	5.33%	22.12
	Propane	0.0701	3.98%	19.99
Non-Res (30-yr)	Electricity	0.0481	2.33%	42.71
	Natural Gas	0.0329	4.78%	64.00
	Propane	0.0397	3.21%	49.25

6 Source Energy Metric

The 2022 TDV code cycle includes, for the first time, a second hourly metric – long run marginal source energy. Long run marginal source energy, in this application, is defined as the source energy of fossil fuels following the long-term effects of any associated changes in resource procurement. Given the long lifetime of this analysis, and the significant changes in state emissions targets and clean energy procurement policy, it is appropriate to take a long-term view of source energy, and how it evolves over the lifetime of a building. This new metric focuses specifically on the amount of fossil fuels that are combusted in association with demand side energy consumption. Including this as a metric provides a new pathway for state regulators to align building codes and standards with the state's environmental goals. Long run marginal source energy is calculated differently for electricity, natural gas, and propane consumption, based on the planned resource changes for a given fuel.

While TDV is a financial metric, and represents the time-value on money, source energy is strictly defined by lifetime fossil fuel consumption. Unlike TDV, source energy does not discount future years. To calculate source energy for a given hour, the value in that hour for each forecasted year is averaged to get a lifetime average source energy. To get lifetime source energy consumption, one would simply multiply each hour's value by the lifetime of the building (15 years or 30 years).

6.1 Electricity Source Energy Methodology

For electricity, long run marginal source energy is calculated by starting with immediate impacts of changes in load on the grid – the short run marginal source energy. As an example, when new load is brought online, there is an immediate, direct increase in source energy from the marginal generator, based solely on generator availability; this represents short run marginal source energy. Depending on when that new load comes online, the immediate impact could be met by increasing the output of a natural gas power plant (higher marginal source energy), or by increasing the output of solar generation that had previously been curtailed (this would have zero marginal source energy).

While short run source energy represents the immediate impacts of new load, it is important to consider two effects that form the basis for long run marginal source energy. First, in the context of building standards, impacts on load are being assessed across a 15- or 30-year lifetime. Second, there are statewide electricity supply side planning constraints that impose renewable procurement requirements on all load that is served. If there is a 50% RPS, for example, by the end of a planning year, load serving entities must procure enough incremental renewable energy so that new annual consumption is offset 50% by new renewable generation. As the RPS constraint grows stricter in following years, the new load will be served by an increasingly higher percentage of renewable energy, thus mitigating potential increases in natural gas consumed to generate electricity. Since these electricity procurement targets are assessed on an annual basis, renewable generation does not need to be integrated in the specific hour that new load takes place; instead load serving entities must just find enough net reductions over the course of a planning year to offset the impacts of new load.

The calculation for long run marginal emissions is broken into the following steps:

1) Calculate short run marginal source energy based on hourly wholesale electricity market prices

2) Calculate avoided source energy from the incremental renewable generation portfolio

3) Subtract the impact of increased renewable generation from short run marginal source energy

6.1.1 CALCULATING SHORT RUN MARGINAL SOURCE ENERGY

Short run marginal energy is defined as the heat rate of the marginal generating resource, plus delivery losses. Similar to calculating Cap and Trade Emissions in electricity TDV (see Section 3.2.5), short run marginal source energy is based on modeled hourly wholesale electricity prices. Given an hourly wholesale energy price forecast, volumetric costs (fuel costs and variable operations and maintenance costs) are used to calculate an implied marginal heat rate. If the implied marginal heat rate is outside of the bounds of the known physical characteristics of existing natural gas power plants, it is then capped at an upper or lower limit. The resulting source energy is multiplied by the transmission and distribution system losses.

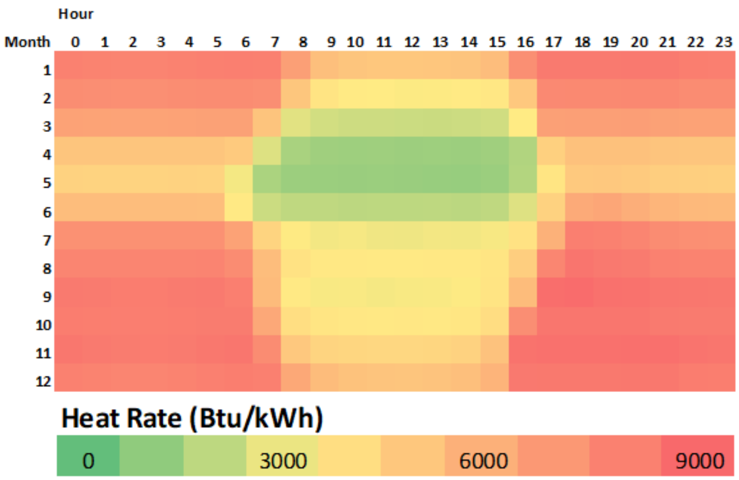
In this calculation, the physical bounds for source energy are seen in Table 19. Transmission and Distribution system loss inputs are the same as used in Section 3.2.3.

Table 19 Power Plant Heat Rate Bounds used to Calculate Source Energy

	Upper Bound - Proxy Low Efficiency Plant	Lower Bound – Renewable Generation
Heat Rate (Btu/kWh)	12,500	0

Short Run Source Energy is displayed below in Figure 61.

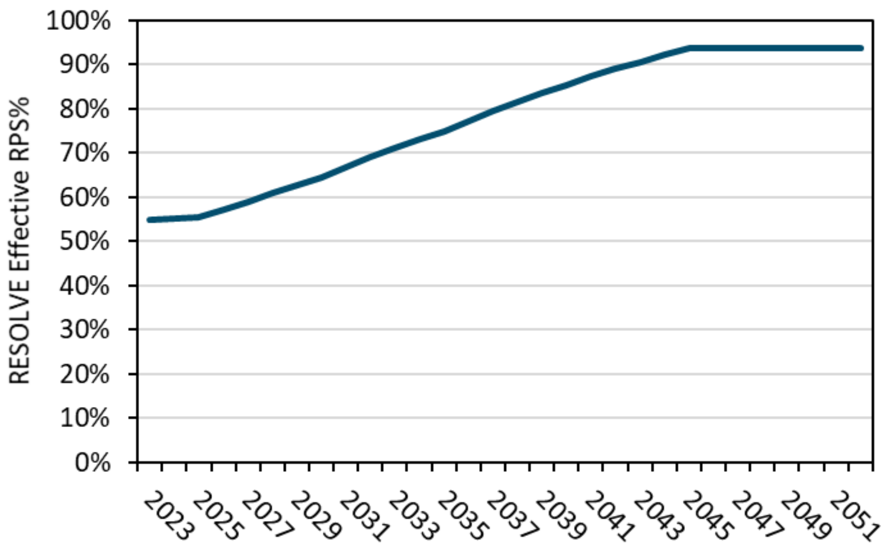
Figure 61 Heat Map Displaying Month-hour Average of Short Run Source Energy



6.1.2 CALCULATING AVOIDED SOURCE ENERGY OF RENEWABLE GENERATION

Next, the avoided source energy of a corresponding increase in renewable generation is calculated. This is dependent on the policy-driven penetration of renewable energy, and the generation profile of the selected renewable resources. While the greenhouse gas emissions are a driving constraint of RESOLVE's resource build, the emissions limit have a corresponding RPS%, that is consistent with SB100, seen in Figure 62. This RPS percentage indicates the amount of renewable energy that must be procured to offset increases in load and remain consistent with SB100.

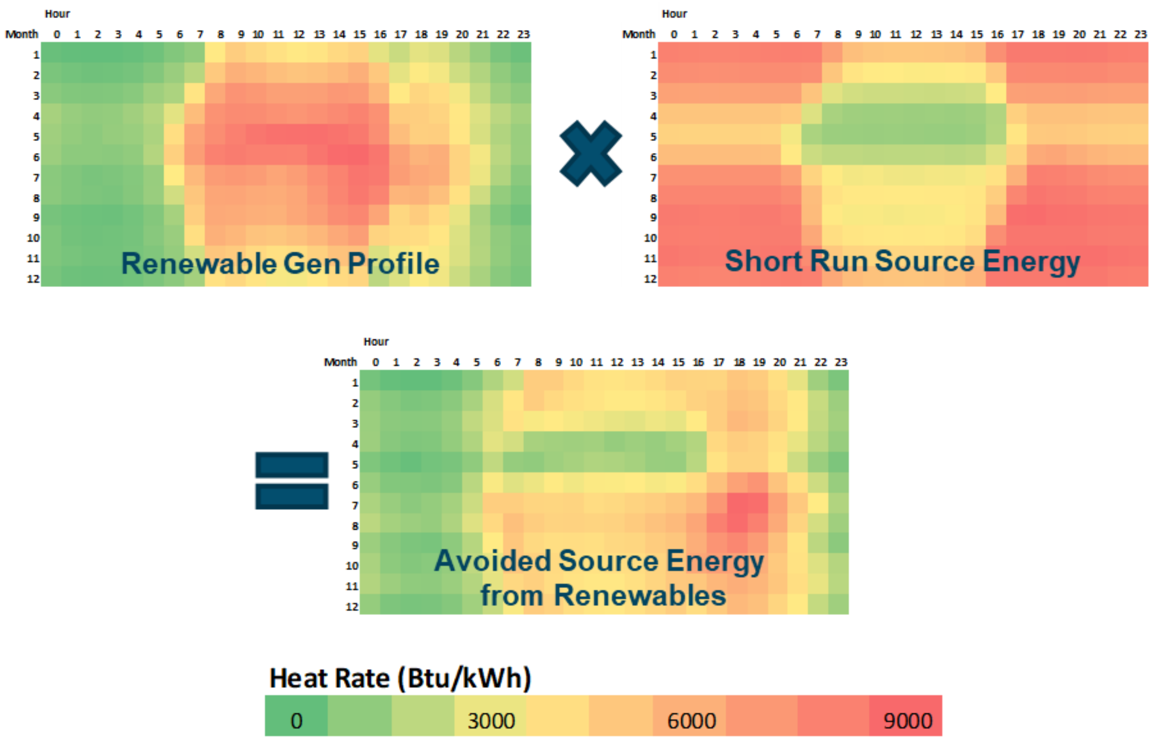
Figure 62 RPS Percentage from the Selected RESOLVE Scenario



To achieve the supply side resource procurement targets, RESOLVE selects candidate resources, which have unique hourly generation profiles. A representative hourly renewable generation profile of incremental RPS resources is aggregated up based on the individual resource profiles, and weighted based on their proportional build amounts in RESOLVE's new resource portfolio, seen in Figure 63. Depending on the generation profile of a given resource, the amount of avoided source energy can vary for each incremental unit of renewable energy. Resources like wind or energy storage that can provide renewable energy in hours when natural gas power plants are the marginal resource have a higher impact on avoided source energy. The normalized hourly renewable generation profile is then multiplied by the hourly short run source energy to determine the avoided source energy for each incremental annual MWh of renewable generation that is built.

$$\frac{Annual\ Avoided\ Source\ Energy}{Incremental\ Renewable\ Energy\ Generated}_y \left[{}^{Btu}/_{kWh}\right]$$
$$= \sum_{h=1}^{8760} Normalized\ Renewable\ Gen_h \left[{}^{Hourly\ MWh}/_{Annual\ MWh}\right]$$
$$* \ Short\ Run\ Source\ Energy_h$$

Figure 63 Source Energy Impacts of Renewable Generation Build



To account for the change in RPS-driven procurement, based on a change in demand side load, the annual avoided source energy is scaled by the RPS percentage for a given year.

$$Renewable\ Energy\ Build\ Impact_y = RPS\%_y * \frac{Annual\ Avoided\ Source\ Energy}{Incremental\ Renewable\ Energy\ Generated}$$

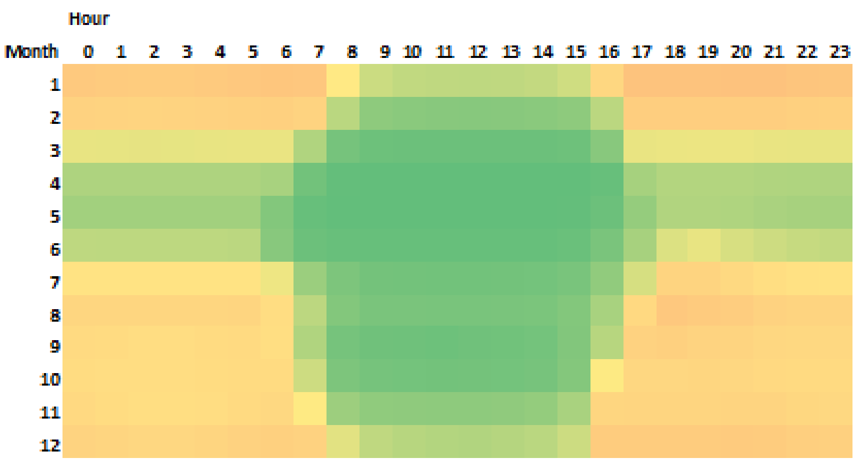
6.1.3 CALCULATING LONG RUN SOURCE ENERGY

Putting these pieces together, the hourly long run marginal source energy is then calculated as the hourly short run marginal source energy, less the annual source energy impact of the renewable build margin. To prevent negative source energy, a lower bound is set at 0 Btu/kWh.

$$\begin{aligned} &Long\ Run\ Marginal\ Source\ Energy_{h,y}\left[{}^{Btu}/_{kWh}\right] \\ &\quad = Max\ \big(Short\ Run\ Marginal\ Source\ Energy_{h,y} \\ &\quad - Renewable\ Energy\ Build\ Impact_y, 0\big) \end{aligned}$$

For electricity, long run marginal source energy has a similar hourly shape to wholesale energy prices, as seen in Figure 64 with low or zero source energy during periods of heavy solar generation, along with higher source energy in periods where natural gas power plants are the marginal grid resource.

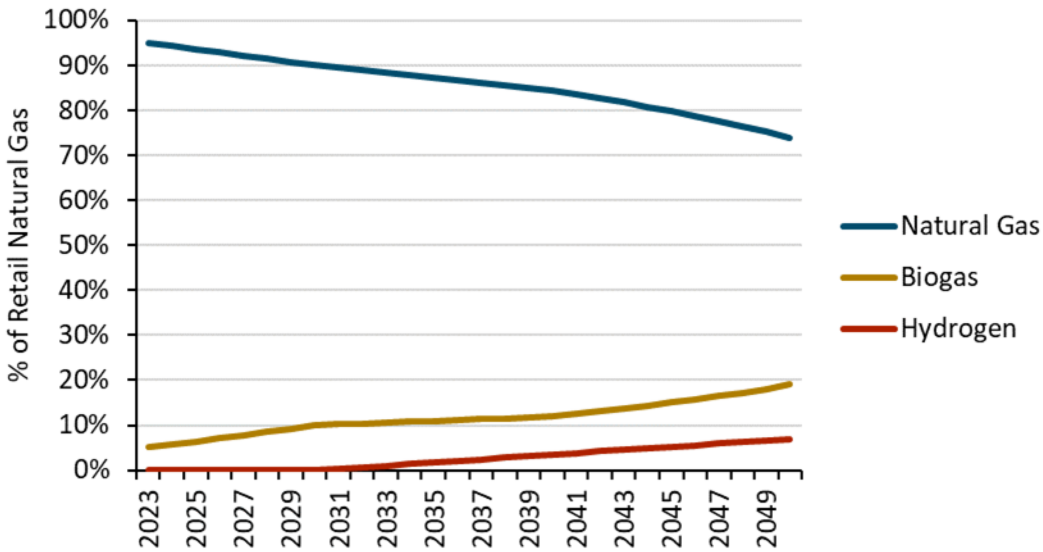
Figure 64 Month hour averages of electricity long run marginal source energy for 2022 TDV



6.2 Natural Gas Source Energy

For natural gas, long run source energy is based on an increasing percentage of renewable gas (either biogas or hydrogen) being injected into the pipeline. Similar to electricity, if a load serving entity is committed to serving 10% of natural gas consumption with renewable gas for a given year, enough renewable gas must be procured and injected into the pipeline over the course of the year. If gas load increases or decreases, the load serving entities burden to procure incremental renewable gas would also increase or decrease. While there are currently no binding renewable gas procurement policies in the state of California (such as a Renewable Fuel Standard), this analysis uses renewable gas blend goals from the selected PATHWAYS scenario, shown in Figure 65. Increasing the amount of renewable gas in the pipeline decreases the source energy impact of retail natural gas consumption.

Figure 65 Retail natural gas fuel blend used in 2022 TDV



6.3 Propane Source Energy

In this analysis, retail propane does not have any renewable gas offsetting short run source energy. Therefore, the long run marginal source energy of propane is defined as the source energy of propane gas and calculated as a direct conversion factor of 100 kBtu/th.

6.4 Calculating Lifetime Source Energy

As source energy is not a financial metric, it is not appropriate to discount this value when approaching a lifecycle metric. Current source energy metrics represent a lifetime average value for each hour of the year. In order to translate the source energy metric into a lifetime value, the hourly values should simply be multiplied by the desired lifetime of the building – 30 years for residential, and 15 or 30 years for non-residential. This lifetime source energy metric represents the lifetime consumption of fossil fuels based on the hourly or annual consumption of a given building.

Appendix A Non-Combustion Emissions Study

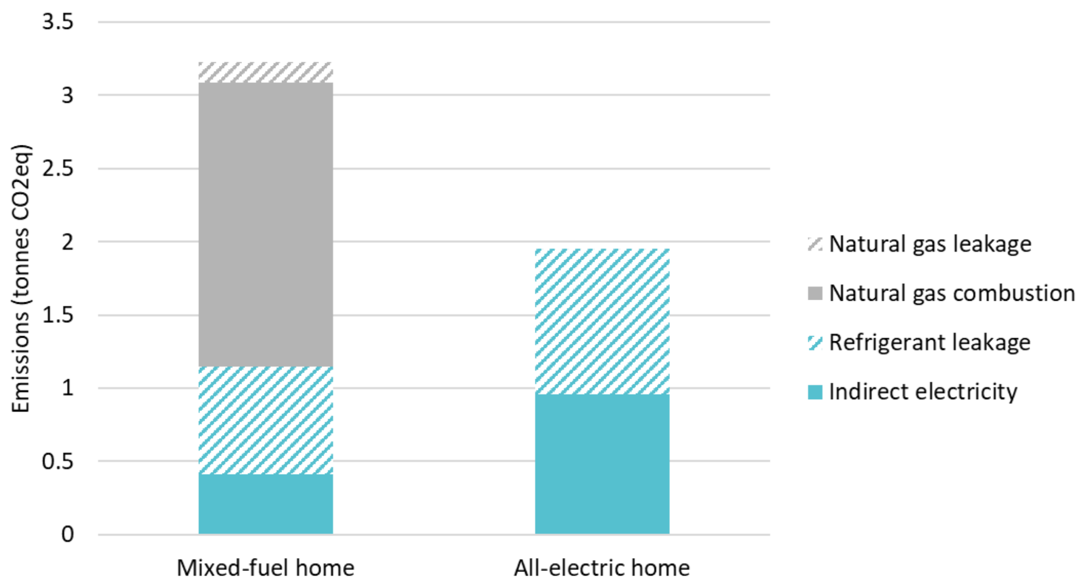
A.1 Non-Combustion Emissions Overview

Refrigerant leakage from heat pumps and air conditioners, as well as methane leakage in the natural gas system, can represent a significant portion of lifecycle GHG emissions from buildings. Refrigerant leakage emissions are likely to be higher in all-electric buildings, as these buildings will have more heat pumps, while lifecycle methane leakage emissions are likely to be lower. Neither of these emissions sources have been accounted for in previous TDV code cycles. Including them in the TDV framework represents an important opportunity to properly quantify the lifecycle emissions from buildings, and to incentivize building designers to use low-GWP refrigerants. In this section, we describe a proposed methodology to incorporate emissions from refrigerant and methane leakage into the analytical framework for the 2022 TDV code cycle. Methane leakage emissions are directly included in electricity and natural gas TDVs. Refrigerant leakage emissions are converted to TDV, but are implemented separately from electricity, natural gas, and propane TDV.

A.2 Refrigerant Leakage Background

As California pursues higher levels of building electrification, through SB 1477 programs, changes in building codes, energy efficiency measures, and other efforts, many more heat pumps will be purchased and used in the state. All heat pumps use refrigerants, and most refrigerants used today are very strong greenhouse gases— as much as 2,000 times stronger than CO_2. The ratio of global warming impact relative to that of CO_2 is known as Global Warming Potential, or GWP. Refrigerants only contribute to global warming when they leak, but leakage is inevitable given current practices. Emissions from refrigerant leakage in all-electric buildings can be a significant portion of a building's lifecycle GHG emissions.

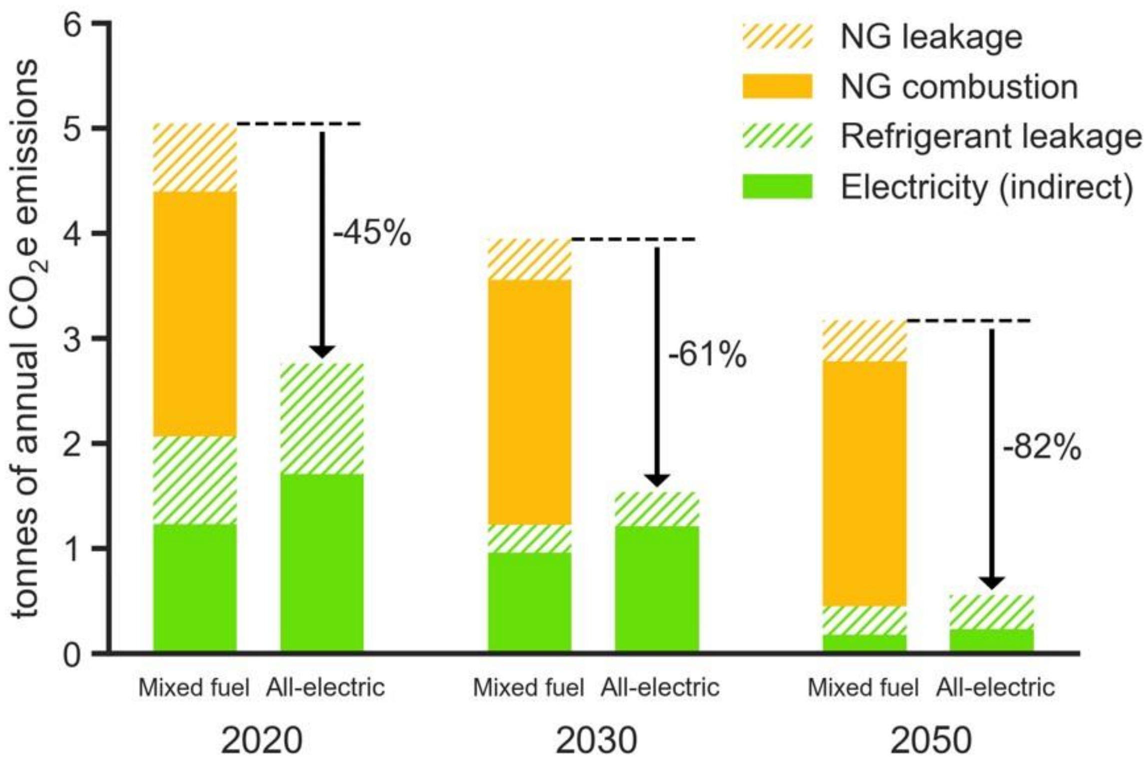
Figure 66: Annual emissions from a sample residential building model. Note that refrigerant leakage in the all-electric home is about half of the overall annual emissions.



When switching from a mixed-fuel building to an all-electric one, GHG emissions related to natural gas (in gray above) decrease, but GHG emissions from refrigerant leakage (blue hashed bar) *increase*. Switching to heat pumps that use lower-GWP refrigerants would decrease these refrigerant leakage emissions. Figure 66 illustrates that even though refrigerant leakage emissions and upstream electric grid emissions increase in an all-electric building relative to a mixed-fuel one, these increases are typically outweighed by a decrease in natural gas direct and indirect emissions. Note that the refrigerant leakage emissions in the mixed-fuel building are due to air conditioners. Air conditioners often use the same (high-GWP) refrigerants as heat pumps.

Figure 67 shows the CO2 equivalent emissions by source for a mixed fuel and electric home in 2020, 2030 and 2050 from an E3 report on building electrification in California. This chart illustrates how declining GHG emissions intensity of the electric grid over time will increase the proportion of global warming impacts attributed to refrigerant leakage, natural gas leakage and natural gas combustion. It will also increase over time the net GHG impact of electrifying buildings relative to the example shown above. Including refrigerant and methane leakage in the TDV framework will thus become increasingly important for evaluating the GHG impacts of electrification.

Figure 67: Annual GHG Emissions from a Mixed-fuel and All-electric 1990's Vintage Home in Sacramento[29]



The most common refrigerants found in new HVAC heat pumps and heat pump water heaters available today have 100-yr GWPs in the range of 1,400-2,000. Lower GWP refrigerants are available and are actively being developed by refrigerant and heat pump manufacturers, but they often have slightly lower performance, require specially designed heat pumps that might be more expensive, and/or require special installation and maintenance practices to account for their mild flammability. Mildly flammable refrigerants are currently not allowed under the Mechanical and Fire Codes in California, but this may change in the near

[29] Energy and Environmental Economics (E3), "Residential Building Electrification in California: Consumer Economics, Greenhouse Gases and Grid Impacts". April 2019. Developed for Southern California Edison (SCE), Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP)

future. Currently no "perfect" low-GWP refrigerant exists with no drawbacks; trade-offs are inevitable. However, it is important to account for the potential reduction in emissions from using low-GWP refrigerants, so that the benefits of using these refrigerants can be compared to their costs, and so that their use can be incentivized.

Table 20: Common refrigerants in use today

Refrigerant	100-year Global Warming Potential (GWP) [30]	Common Uses
R-410A	2,088	New heat pumps and air conditioners
R-134A	1,430	New heat pump water heaters
R-22	1,810	Existing air conditioners (R-22 is mildly ozone-depleting and is being phased out in the US)

Table 21: Low-GWP refrigerant alternatives

Refrigerant	100-year Global Warming Potential (GWP)	Common Uses
R-32	675	Most promising near-term replacement for R-410A in residential HVAC heat pumps
R-1234yf	4	One of the more promising near-term replacements for R-134A in heat pump water heaters and clothes dryers
Propane (R-290)	3	Can be used in any heat pump, but high flammability means special installation and maintenance practices are required.
CO2 (R-744)	1	Some automobile air conditioners in Europe, some heat pump water heaters in Japan.

[30] GWPs listed are the same as those used by the CARB Refrigerant Management Program, which are IPCC AR4 (2007). See https://ww2.arb.ca.gov/resources/documents/high-gwp-refrigerants

A.3 Refrigerant Leakage Emissions Methodology

Avoided refrigerant leakage emissions will be quantified using detailed leakage data compiled by the California Air Resources Board (CARB). CARB maintains a database of typical refrigerant charge, annual leakage rates, and end-of-life leakage rates for all major types of residential and non-residential equipment that uses refrigerants. The table below shows leakage data available from CARB for common residential equipment types. Additionally, this database includes typical refrigerants and leakage rates for other residential applications and most commercial applications.

Table 22: Refrigerant leakage data compiled by the California Air Resources Board. [31]

Appliance	Typical refrigerant	Refrigerant GWP	Average refrigerant charge	Average annual leakage	Average end-of-life leakage
Central A/C	R410A	2088	7.5 lbs	5%	80%
Air-source ducted heat pump	R410A	2088	8.2 lbs	5.3%	80%
Heat pump water heater	R134A	1430	2.4 lbs	1%	95%
Heat pump clothes dryer	R134A	1430	0.88 lbs	1%	100%

[31] Data obtained via correspondence with CARB staff. Similar (but not exactly the same) data is available in the latest technical support document (https://ww3.arb.ca.gov/cc/inventory/slcp/doc/hfc_inventory_tsd_20160411.pdf) for the CARB HFC Inventory.

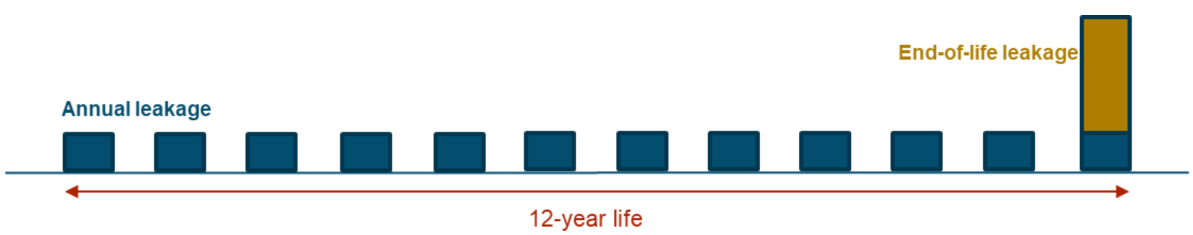
This leakage data can be converted into annualized leakage rates by adding the end-of-life leakage divided by the expected equipment lifetime, and subsequently to annualized emissions by multiplying by refrigerant charge and GWP:

$$\text{Annualized emissions} = \text{Refrigerant charge} * \text{GWP} * (\text{Annual leakage rate} + \frac{\text{End-of-life leakage rate}}{\text{lifetime}})$$

With an annualized emissions factor calculated in tCO_2-e, this can be factored into the TDV cost metric using the annual cost of economy wide emissions abatement [\$/tCO_2-e], and then taking the present value of the total. While it would technically be more accurate to value end-of-life leakage with the emissions abatement cost of the year that leakage takes place, and then levelize the total cost, this would cause an uneven treatment of end-uses with slightly different lifetimes. For example, in a 30 year timeframe considered in TDV, an appliance with a 14-yr lifetime would experience two end-of-life leakages, while an appliance with a 16-yr lifetime would only experience one end-of-life leakage, and thus appear to be a significantly lower emitter. Using an annualized average solves this problem by attributing a portion of the end-of-life leakage to each year, thus creating a smooth signal.

Lifetime refrigerant leakage emissions can then be converted to kBtu/kWh using standard TDV conversion factors and added to the final TDV score. This framework allows for the reduction in emissions from using lower-GWP refrigerants to be appropriately accounted for. In this analysis, refrigerant leakage does not have an associated source energy penalty and is not included in the source energy metric.

Figure 68: Visualization of refrigerant leakage accounting methodology.



Annualized leakage = (Annual leakage rate) + (End-of-life leakage)/lifetime

A.4 Methane Leakage Background

Another potentially significant benefit of electrifying buildings that has not yet been reflected in the TDV framework is the potential for avoided methane leakage emissions. Global Warming Potential (GWP) is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time relative to the emissions of 1 ton of CO2. The larger the GWP, the more that a given gas warms the Earth compared to CO2 over that time period. Methane, the primary component of natural gas, has a 100-year GWP of 25, and a 20-year GWP of 72[32]. A 100-year GWP of 25 means that methane has a net warming effect that is 25 times stronger than CO2 over a 100-year time horizon; any leakage of uncombusted methane has a disproportionately high impact on global warming compared to burning that same methane and emitting CO2 instead. Methane has an even higher GWP if a shorter time horizon is used, as its lifetime in the atmosphere is only about 12 years before it decomposes.

CARB tracks and reports methane leakage using both 20-year[33] and 100-year[34] GWP through the Short-Lived Climate Pollutant (SLCP) program[35]. CARB uses both 20-year and 100-year GWP values for economic impact evaluation[36]. Through coordination between CEC and CARB staff, it was determined that it is appropriate to use a 20-year GWP for methane leakage emissions in the context of studying the economic impact of California's building standards, therefore the 2022 TDV adopts the 20-year GWP value for leaked methane.

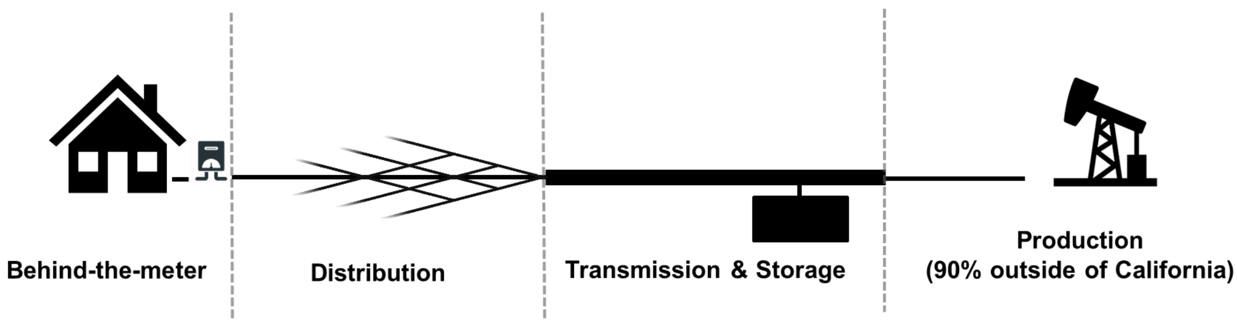
Methane leakage is inherently difficult to quantify, given that much of the leakage that occurs is due to abnormal, infrequent events, and even more difficult to quantify is the amount of methane leakage that is possible to avoid by electrifying buildings. California will continue to have a pressurized natural gas system for at least the next few decades, so any leakage associated with simply keeping this system pressurized is not likely to be avoided by decreasing throughput. However, there is certainly a nonzero quantity of methane leakage that will be avoided by electrifying buildings. At the least, behind-the-meter leakage will

[32] CARB GHG Inventory uses GWP numbers from IPCC AR4 (2017), Table 2.14 **https://www.ipcc.ch/site/assets/uploads/2018/02/ar4-wg1-chapter2-1.pdf**. See **https://ww2.arb.ca.gov/ghg-gwps**
[33] CARB SLCP Methane Emissions Inventory 20-year AR4 GWP: **https://ww3.arb.ca.gov/cc/inventory/slcp/data/slcp_ch4_20yr1.pdf**
[34] CARB SLCP Methane Emissions Inventory 100-year AR4 GWP: **https://ww3.arb.ca.gov/cc/inventory/slcp/data/slcp_ch4_100yr1.pdf**
[35] CARB SLCP Program Overview: **https://ww2.arb.ca.gov/our-work/programs/short-lived-climate-pollutants/about**
[36] For example, see: CARB Oil and Gas Regulation Staff Report: **https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasisor.pdf**

be eliminated. At the most, leakage that happens during production, storage, and transmission will also be reduced as a result of decreased throughput.

In the following paragraphs, we walk through the sources of methane leakage in the natural gas system, and their potential for being reduced due to building electrification.

Figure 69: Sources of leaks in the natural gas system.



A.4.1 PRODUCTION EMISSIONS

Leakage during production and gathering is the largest source of methane leakage in the natural gas system.[37] Under normal operation absent any malfunctioning, leakage happens during exploration, the completing of wells ("well completions"), and routine "liquids unloadings" which involve removing undesired liquids from the natural gas extraction stream. Leakage can also happen during rare, but severe, malfunction events such as a leak in a storage tank or valve. These rare events make it difficult to estimate an average leakage rate, as the distribution of emissions from production facilities is generally considered to have a long "tail," i.e. only a few emitters have very high emissions, and the majority of emitters have low

[37] Alvarez, Ramón A., et al. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." *Science*, vol. 361, no. 6398, 21 June 2018, pp. 186–188., doi:10.1126/science.aar7204.

emissions. Estimates for the methane leakage rate of natural gas production range from 1.4% to 12%.[38,39,40,41,42]

While natural gas production emissions are a significant proportion of lifecycle emissions associated with natural gas consumption, the only emissions that matter when we seek to incorporate leakage emissions into the Title 24 framework are those that could be avoided by reducing consumption. In other words, similar to when we analyze electric grid emissions, we only care about the "marginal" emissions. There are several issues that prohibit us from being able to give building electrification full "credit" for reducing production emissions (that is, including the full lifecycle emissions from production into the TDV framework):

- A large proportion of natural gas extraction is associated gas, meaning it is co-extracted with oil. Changes in natural gas consumption will not change how much associated gas is produced, nor will it change how much leakage happens due to the extraction of this associated gas.
- Leakage from rare malfunction events is not a function of consumption, and we have not seen any evidence suggesting that these events could be averted by decreasing natural gas throughput. These events are generally the result of non-compliance with EPA rules, and thus it is the jurisdiction of the EPA to avoid these emissions.
- California imports over 90% of its natural gas, so most upstream production emissions associated with CA natural gas are not covered by the CARB GHG inventory, the metric by which we measure state progress toward climate goals.

However, it is possible that some proportion of natural gas production emissions could be reduced by decreasing consumption. Roughly 30% of fossil wells must be replaced with new wells each year as old wells are depleted, so reducing natural gas consumption on a large enough scale could mean that fewer new wells are drilled. Fewer new wells drilled would mean avoided leakage from one-time events such as well completions. The magnitude of decrease in natural gas consumption required to avoid new wells is uncertain and requires further study.

[38] Alvarez et al. 2018, previously cited

[39] U.S. Environmental Protection Agency (EPA), "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015" (EPA, 2017); www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2015.

[40] Miller, S. M., et al. "Anthropogenic Emissions of Methane in the United States." Proceedings of the National Academy of Sciences, vol. 110, no. 50, 10 Dec. 2013, pp. 20018–20022., doi:10.1073/pnas.1314392110.

[41] Howarth, Robert. "Methane Emissions and Climatic Warming Risk from Hydraulic Fracturing and Shale Gas Development: Implications for Policy." Energy and Emission Control Technologies, vol. 2015, no. 3, 8 Oct. 2015, pp. 45–54., doi:10.2147/eect.s61539.

[42] Howarth, Robert W., et al. "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations." Climatic Change, vol. 106, 12 Apr. 2011, pp. 679–690., doi:10.1007/s10584-011-0061-5.

A.4.2 TRANSMISSION AND STORAGE EMISSIONS

Leakage from transmission and storage is also a significant source of methane leakage in the natural gas system. Gas transmission lines have valves and venting stations which have inevitable leaks, and gas storage tanks frequently have leaks as well.

The proportion of leakage during transmission and storage that can be considered "marginal" to consumption is unclear. As long as we have some amount of natural gas consumption, we will have to maintain a pressurized transmission and storage system, which will have some leaks associated with it. However, one recent study showed that methane leakage in the LA basin is highly correlated with consumption, which implies that leakage from natural gas transmission and storage may vary with consumption.[43] Further study is required to determine exactly how much leakage in the natural gas transmission and storage system could be avoided by decreasing consumption.

A.4.3 DISTRIBUTION AND BEHIND-THE-METER EMISSIONS

Leakage in the distribution system is similar to that in the transmission system, in that leakage will continue as long as we have a pressurized distribution system. However, the distribution system is different in that significant amounts of natural gas distribution infrastructure could be avoided or shut down due to building electrification. If a new neighborhood in California is built all-electric instead of mixed-fuel, there will be no need for a gas distribution system in this neighborhood, and therefore no methane leaks. This can happen on an individual house level as well. Leakage at the meter, which is a significant portion of distribution system leakage,[44] will be avoided if there is no natural gas meter needed for an all-electric new construction building.

The final leakage source in the natural gas system is behind-the-meter leakage. This leakage source is newly quantified in the year-2017 CARB inventory published in 2019, based on a recent CEC study.[45] Behind-the-meter leakage is certain to be zero in all-electric new construction. However, the magnitude of leakage in

[43] He, Liyin, et al. "Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles." Geophysical Research Letters, vol. 46, no. 14, 2019, pp. 8563–8571., doi:10.1029/2019gl083400.
[44] Rongere, François. "Methane Emissions from Gas Residential Meter Set." Presentation by Pacific Gas & Electric Company, January 2019
[45] Fischer, Marc L., Wanyu Chan, Seongeun Jeong, and Zhimin Zhu. Lawrence Berkeley National Laboratory. 2018. *Natural Gas Methane Emissions From California Homes*. California Energy Commission. Publication Number: CEC-500-2018-021.

mixed-fuel new construction is unclear, as the CEC study used in the ARB inventory studied mostly older homes that did not use modern construction techniques. Other studies suggest, though, that appliances present in new construction homes such as tankless water heaters are likely to still have significant leakage.[46] Thus, it is unclear exactly how much behind-the-meter leakage would be avoided by all-electric new construction; this question requires further study.

A.5 Methane Leakage Emissions Methodology

Given the uncertainty surrounding how much of the lifecycle leakage emissions associated with natural gas consumption are marginal, we propose to use the ARB inventory estimate of in-state methane leakage for calculating avoided methane leakage emissions. This estimate is not perfect since it includes some emissions from in-state production, transmission, storage, and distribution, which will all continue to some degree unless the natural gas system is shut down in its entirety. However, it is the best estimate available given research we are aware of, and studies such as the LA basin study mentioned above suggest that, on the whole, methane leakage is highly correlated with consumption. We also know that the behind-the-meter leakage included in this leakage adder will certainly be avoided due to electrifying buildings. To refine this estimate in future work, we suggest the following lines of research:

- Research on the magnitude of methane leakage in mixed-fuel new construction homes, which will allow us to accurately determine how much leakage can be directly avoided by all-electric new construction.
- Research on the degree to which upstream leakage in the natural gas production, transmission, storage, and distribution systems is a function of consumption.

For this code cycle, the leakage adders are calculated using CO2-equivalent emissions numbers from the 2017 GHG inventory published by the ARB.[47] The ARB inventory is a record of all GHG emissions occurring

[46] Merrin, Zachary, and Paul W. Francisco. "Unburned Methane Emissions from Residential Natural Gas Appliances." *Environmental Science & Technology*, vol. 53, no. 9, 25 Mar. 2019, pp. 5473–5482., doi:10.1021/acs.est.8b05323.
[47] The 2017 ARB inventory (Economic Sector categorization) can be found here: **https://ww3.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_all_00-17.xlsx** . This is the most recent version of the inventory.

within the state borders of California, plus any out-of-state GHG emissions from electric generators supplying electricity to California.

There are three categories of methane leakage that are included in the ARB inventory: 1) Oil & Gas Production and Processing, 2) Natural Gas Transmission and Distribution, and 3) Residential Behind-the-Meter (BTM). The methane leakage in categories 1) and 2) reflects the "upstream" methane leakage occurring within state boundaries and is thus assumed to apply to all natural gas consumed in California. The CO_2-equivalent methane leakage in these categories is divided by the CO_2 emissions from all natural gas consumption in California, to arrive at the upstream in-state methane leakage adder of 5.57%. Note that the methane leakage emissions from production and processing of natural gas imported to California from out-of-state (representing about 90-95% of natural gas consumption in California) are not included in this estimate, so this 5.57% is significantly lower than it would otherwise be if these out-of-state emissions were included. These out-of-state emissions are not currently in the ARB inventory, which is why they are not currently included in this upstream emissions estimate. Also note that the CO_2-equivalent methane leakage included in the ARB inventory is calculated using the 100-year GWP for methane.

Similarly, the residential behind-the-meter leakage adder of 3.78% is calculated by dividing the CO_2-equivalent methane leakage emissions in category 3) above by the CO_2 emissions from residential natural gas consumption only. This second adder applies only to natural gas consumed in residential buildings.

These methane leakage **adders** are distinct from methane leakage **rates**. Methane leakage rates reflect the percentage of unburned natural gas that is leaked across the lifecycle of natural gas consumption. Methane leakage adders reflect the impact of this leaked natural gas on the GHG intensity of natural gas, which is what is required for incorporating methane leakage into the TDV framework. A leakage adder is higher than its corresponding leakage rate due to the high GWP of methane. These two values are calculated in the following way:

- Methane leakage rate = $\frac{mass\ of\ natural\ gas\ leaked}{mass\ of\ natural\ gas\ consumed}$
  - Answers the question: "What percent of my natural gas supply was leaked?"

- Methane leakage adder = $\frac{CO2\text{-}equivalent\ emissions\ from\ leaked\ natural\ gas}{CO2\ emissions\ from\ burned\ natural\ gas}$
  - Answers the question: "How does this leaked methane increase the overall GHG emissions from natural gas consumption?"

At first glance, one might guess that the leakage adder is simply equal to the leakage rate times the GWP of methane, equal to 25 over a 100-year time horizon. However, this is not the case, because methane actually *gains mass when it is burned* due to being oxidized with oxygen-- each tonne of methane yields 2.74 tonnes of CO_2 when it is burned. Thus, the conversion from a methane leakage rate to a methane leakage adder is done in the following way:

methane leakage rate

methane leakage adder

$$\frac{mass\ of\ methane\ leaked\ (tonnes\ CH4)}{mass\ of\ methane\ consumed\ (tonnes\ CH4)} \begin{array}{c} \rightarrow * \frac{25\ tonnes\ CO2eq}{tonne\ CH4\ leaked} \rightarrow \\ = \\ \rightarrow * \frac{2.74\ tonnes\ CO2}{tonne\ CH4\ burned} \rightarrow \end{array} \frac{CO2eq\ emissions\ from\ leaked\ NG}{CO2\ emissions\ from\ burned\ NG}$$

And therefore, because 25/2.74 = 9.1:

$$methane\ leakage\ rate * 9.1 = methane\ leakage\ adder$$

Thus, for 100-year GWP, the conversion factor between a methane leakage rate and a methane leakage adder is actually 9.1, not 25[48]. For a 20-yr GWP of 72, the conversion factor is 26.3.

Another way of looking at this is that on a tonne by tonne basis, methane does have 25 times the impact of CO_2. In other words, releasing a tonne of methane to the atmosphere has 25 times the global warming impact of releasing a tonne of CO_2 to the atmosphere (over 100 years). However, we are not comparing methane to CO_2 on a tonne by tonne basis. Rather, we are comparing methane leakage to CO_2 combustion.

[48] Note that this calculation assumes, for explanation purposes, that natural gas is 100% methane. In reality natural gas is about 95% methane, so the conversion factor of 9.1 would have to be modified slightly to account for this. However, since TDV only relies on the leakage adders, which are calculated directly from the ARB inventory and do not require the conversion factor of 9.1, it is not necessary to account for this adjustment for the purposes of developing methane leakage estimates for TDV. This example using a 9.1 conversion factor is included for illustrative purposes and to tie this methodology to approaches outlined in previously public stakeholder workshops.

In other words, we are comparing tonnes of natural gas that we intended to combust but accidentally leaked instead with tonnes of natural gas that we are burning for fuel and thus producing CO_2 as a byproduct.

For example, we start out with a tonne of methane. If we leak it, then a tonne of methane will enter the atmosphere, which will have 25 times the global warming impact of a tonne of CO_2. But, if we burn it, because of the different molecular mass of CH_4 (methane) and CO_2, more than 1 tonne of CO_2 will be produced. Burning a tonne of methane produces 2.74 tonnes of CO_2. In order to determine the global warming impact of the leaked methane, we do not want to compare the effect of the leaked methane to that of one tonne of CO_2, but rather to the 2.74 tonnes of CO_2 we would have produced by burning it. So, we divide 25 by 2.74 to get 9.1. Hence, a tonne of methane leakage has 9.1 times the global warming impact if it is leaked compared to if it is burned.

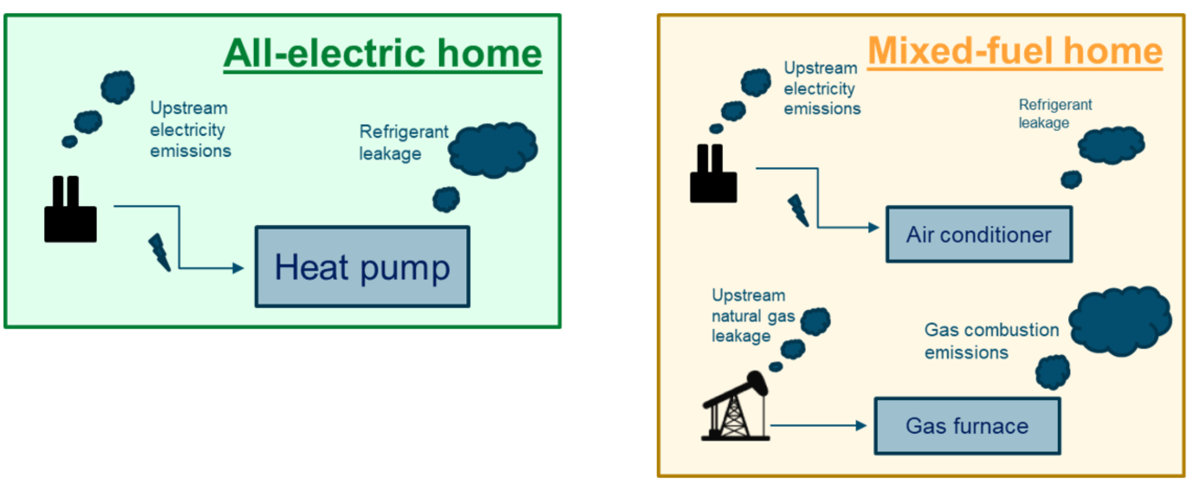
The final methane leakage adders, and their corresponding leakage rates, are included in the table below. Also included are the leakage adder values that correspond to a 20-year GWP for methane, which is calculated by multiplying the 100-year leakage adders by 2.88, the ratio between the 20-year and 100-year GWPs for methane (72 and 25, respectively). All CO_2-e emissions categories in TDV include relevant leakage adders, including end-use natural gas consumption and electricity generation.

Table 23. Leakage adders in TDV and corresponding leakage rates

Leakage type	Leakage rate (% of natural gas consumption)	Leakage adder, 100-year GWP (% of CO2e emissions)	Leakage adder, 20-year GWP Included in 2022 TDV (% of CO2e emissions)
Oil & Gas Production and Processing	0.19%	1.77%	5.09%
Natural Gas Transmission and Distribution	0.42%	3.80%	10.94%
Residential behind-the-meter methane leakage	0.415%	3.78%	10.89%

The below figure summarizes emissions sources in all-electric and mixed-fuel homes, all of which will be incorporated into the proposed TDV framework.

Figure 70: Comparison of All-Electric and Mixed-Fuel Home Leakage



Appendix B Methodology for Creating Weather-Correlated Load Shapes for Use in the TDVs

B.1 Introduction

This appendix describes the statistical methodology used for developing the weather-correlated load shapes, which are used in the production simulation dispatch model to generate hourly market price shapes for the 2022 TDVs.

B.2 Modeling considerations

Modeling a load shape which captures the relationship between historic hourly load and weather data should consider the following:[49]

+ Hour-of-day effect. Hourly MW data exhibits an intra-day pattern. The lowest loads tend to occur around 04:00 and the highest 16:00.
+ Day-of-week effect. Hourly MW data exhibits an inter-day pattern. Hourly loads tend to be low on weekend days and high on mid-weekdays.
+ Month-of-year effect. Hourly loads tend to be high in summer months and low in other months. But this may largely be driven by the monthly temperature pattern.
+ Holiday effect. Hourly loads on the day-before, day-of, and day-after a holiday tend be lower than on other days.
+ Weather effect. Hourly loads move with weather. Hot (cold) days, especially after consecutive hot (cold) days, tend to have higher hourly loads than other days.

[49] Woo, C.K., P. Hander and N. Toyama (1986) "Estimating Hourly Electric Load with Generalized Least Squares Procedures," The Energy Journal, 7:2, 153-170.

+ Peak loads. While a regression-based approach is useful for predicting hourly loads in a typical weather year, it produces a flatter shape than the one in real world. This is because regression-based predictions tend to gravitate towards the mean MW, rather than the maximum and minimum MW, which are, by definition, the two extreme ends of an hourly load distribution. We add a day index variable with continuous integers to capture socio-economic growth within our regression horizon. Additionally, a secondary regression is used to adjust values based on their ranks in a load duration curve.
+ Load growth. The typical weather year load shape's maximum MW should match the system peak MW forecast. If the load modeling is done for normalized MW (= hourly MW / annual peak MW), the resulting prediction can then be scaled to match the forecast peak MW.

B.3 Regression-based approach

We use a regression-based approach to develop equations for predicting a normalized MW shape under the TMY weather. Illustrated with an SCE example, the approach has the following steps:

- Step 1: Using hourly weather and load observations in the 2009-2013 period, we split the datasets into two groups such that all observations with dry bulb temperature greater than or equal to 65°F in one particular weather station (chosen to be Burbank for SCE) are in one group and the remaining observations are in a second group. Then we estimate a linear regression whose dependent variable is s = $log(S)$ where S = hourly MW / annual peak MW for the first dataset group (greater than or equal to 65°F. This step aims to show how hourly MW varies with its fundamental drivers. The explanatory variables are dummy variables for month-of-year, day-of-week, hour-of-day, and Federal holidays; day index variable; and weather variables for some number of relevant stations (five are used in the case of SCE: Fresno, Riverside, Burbank, Santa Maria, and Blue Canyon).
    - Each weather station has two associated sets of variables: one based on the dry bulb temperature, in order to capture effects based solely on temperature, and one based on dew point temperature, in order to capture the added demand for air conditioning on humid days.
    - The weather variables include a series of degree hour values calculated with a reference temperature of 65°F. We include cooling degree hours, heating degree hours, weighted sum of lagged cooling degree days, and weighted sum of lagged heating degree days. The lagged heating and cooling degree days cover a three-day span and are used to

represent cold and heat spells respectively.[50] We also introduce a heating-cooling weight to tackle the asymmetric energy consumption of heating and cooling. The larger this value, the more energy is assumed to be consumed by heating than cooling. We optimize this weighting value to 0.15 to minimize the mean-squared error (MSE). The following equations depict how we arrive at heating degree hours (HDH), cooling degree hours (CDH), and our combined heating-cooling degree hour variable with our weight set to 0.15:

$$HDH = \begin{cases} 0, & 65 - T < 0 \\ 65 - T, & 65 - T \geq 0 \end{cases}$$

$$CDH = \begin{cases} 0, & T - 65 < 0 \\ T - 65, & T - 65 \geq 0 \end{cases}$$

$$DH.Combine = max(HDH \times 0.15, CDH)$$

We use these basic equations to arrive at the weighted sum of lagged cooling degree days, weighted sum of lagged heating degree days, and finally the weighted sum of combined heating-cooling degree hour variable.

+ Step 2: Repeat Step 1 for the remaining hourly observations (less than 65°F). The regression resulting from Steps 1 and 2 can be written as:

$$s = \begin{cases} \beta_0 + \beta_n I + \sum_{n=1}^{11} \beta_{m,n} m_n + \sum_{n=1}^{6} \beta_{d,n} d_n + \sum_{n=1}^{23} \beta_{h,n} h_n + \sum_{n=1}^{1} \beta_{f,n} f_n \sum_{n} \sum_{i=1}^{2} \sum_{j=1}^{2} \beta_{w,i,n,j} w_{n,i,j} + \varepsilon & if\ T_k \geq 65 \\ \eta_0 + \eta_n I + \sum_{n=1}^{11} \eta_{m,n} m_n + \sum_{n=1}^{6} \eta_{d,n} d_n + \sum_{n=1}^{23} \eta_{h,n} h_n + \sum_{n=1}^{1} \eta_{f,n} f_n \sum_{n} \sum_{i=1}^{2} \sum_{j=1}^{2} \eta_{w,i,n,j} w_{n,i,j} + \varepsilon & if\ T_k < 65 \end{cases}$$

Here, β_0 and η_0 are the intercepts; I is the day index variable; m, d, and h are the month of year, day of week, and hour of day indicators; f is the federal holiday indicator; and w is the weather variable, which is summed over all weather stations (n), both dry bulb and dew point temperatures (i), and both lagged and non-lagged combined degree days (j). T_k is the dry bulb temperature at a single weather station, chosen to be the most influential in the region, and ε is the error.

[50] Weight = 1/2 for the day before, 1/3 for two days before, and 1/6 for three days before.

- Step 3: Use the regression results from Step 1 and Step 2 to make a preliminary prediction of an hourly normalized MW for a given weather condition: $S_P = \exp(s_P + v^2/2)$, where s_P = predicted value of $ln(S)$ and v^2 = variance of s_P.
- Step 4: Divide the S_P values from Step 3 into two bins, each containing 50% of the sample, based on each value's rank in a load duration curve. For example, bin "1" has S_P values below the 50-percentile, and bin "2" has values above the 50-percentile.
- Step 5: Run the actual vs. predicted regression:

$$S = \beta_0 + \sum_{n=1}^{2} \beta_{B,n} B_n + B_s s_p + \varepsilon$$

  Here, β_0 is the intercept, B_n is the bin indicator, s_p is the normalized MW, and ε is the error. This step corrects for the fact that the preliminary prediction S_P may not match actual normalized MW.
- Step 6: Compute the final prediction S_F based on the regression result from Step 5. This value is limited to a maximum of 1 so that the annual peak MW value is not exceeded in the next step.
- Step 7: Make hourly MW prediction = S_F * annual peak MW.

B.4 Scaling and Model Inputs

The purpose of this regression-based approach is to produce foundational system load profiles, reflecting the relationship between load and weather profiles. As the profiles of emerging distributed energy resource (DER) technologies such as behind-the-meter generation and electrification of buildings and vehicles fundamentally alter this relationship, it becomes necessary to model each component separately. Consequently, creating weather-matched system load profiles without DERs requires training the regression models on historical data from years where DER impacts were relatively small. To this end, 2009-2013 historical system load profiles by BAA were procured from WECC and cleaned for missing data, time zone, and daylight savings time issues.

Whitebox Technologies provided weather data for WECC BAA load centers for the historical years and the CTZ22 weather year. For each BAA, the regression models were trained with historical loads and weather to predict a year of hourly loads with the CTZ22 weather. The resulting BAA system load shapes were scaled by annual PATHWAYS and CEC IEPR load forecasts for California and non-California, respectively, less building and vehicle electrification. Finally, scaled marginal vehicle and building electrification load shapes are added to these system load shapes to produce total gross load shapes by BAA and year that will go into the PLEXOS model.

B.5 Results

The results of this regression approach show very good prediction of actual loads. In the examples below, predicted and actual loads are compared for the sample of hourly data in 2009 for the SCE region. Figure 71 shows the predicted and actual load duration curves for 2009. Figure 72 shows the actual and predicted MW for the peak week in 2009. Since the predicted curves closely match the actual ones, the regression-based approach is useful for developing a TMY load shape.

Figure 71. 2009 Load Duration Curve for SCE in MW

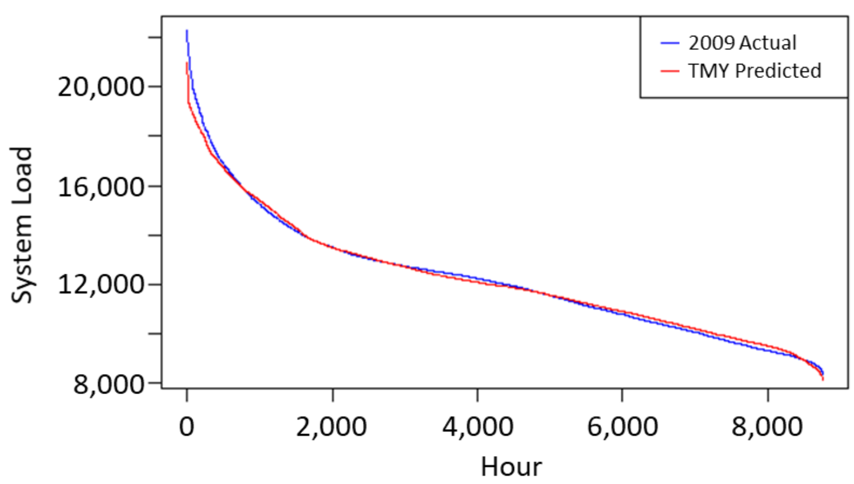
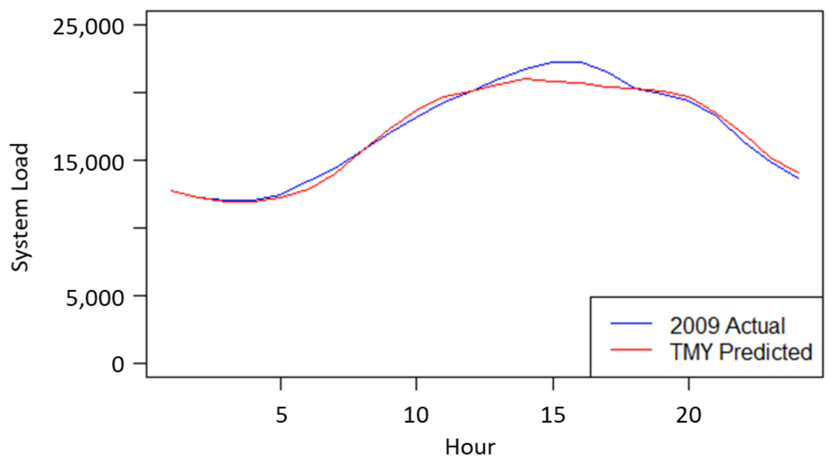


Figure 72. 2009 Peak Load Day for SCE in MW



B.6 Weather Stations used for load shape regressions

The following table shows the utility service territory regions for which revised weather correlated load shapes were developed. The weather station data used in the statistical analysis are shown in the table as well. The weather stations were chosen based on their proximity to well-populated area within each region and are shown in Table 24 below. Table 25 shows weather stations used for loads outside of California in WECC

Table 24. Weather Stations Applied to Each Load Region in California

Load Zone	Territory	Weather Stations
BANC	CA	SACRAMENTO-EXECUTIVE-AP_724830S
IID	CA	PALM-SPRINGS-IAP_722868S
LDWP	CA	BURBANK-GLNDLE-PASAD-AP_722880S TORRANCE-MUNI-AP_722955S
PG&E	CA	ARCATA-AP_725945S OAKLAND-METRO-AP_724930S SACRAMENTO-EXECUTIVE-AP_724830S SAN-JOSE-REID-HILLV_724946S SANTA-MARIA-PUBLIC-AP_723940S SANTA-ROSA(AWOS)_724957S
SCE	CA	BLUE-CANYON-AP_725845S BURBANK-GLNDLE-PASAD-AP_722880S FRESNO-YOSEMITE-IAP_723890S RIVERSIDE-MUNI_722869S SANTA-MARIA-PUBLIC-AP_723940S
SDGE	CA	PALMDALE-AP_723820S RIVERSIDE-MUNI_722869S SAN-DIEGO-LINDBERGH-FIELD_722900S
TIDC	CA	SACRAMENTO-EXECUTIVE-AP_724830S
WALC	CA	NEEDLES-AP_723805S

Table 25. Weather Stations Applied to Each Load Region in WECC, Outside of California

Load Zone	Territory	Weather Stations
AESO	Can-AB	CALGARY-IAP_718770S EDMONTON-IAP_711230S
AVA	WA	SPOKANE-IAP_727850S
AZPS	AZ	PHOENIX-SKY-HARBOR-IAP_722780S
BCHA	Can-BC	VANCOUVER-IAP_718920S VICTORIA-IAP_717990S
BPAT	OR	EUGENE-MAHLON-SWEET-AP_726930S
	WA	SPOKANE-IAP_727850S
CFE	Mex-BC	MEXICALI-G-SANCHEZ_760053S TIJUANA-G-RODRIGUE_760013S
CHPD	WA	PANGBORN-MEM_727825S
DOPD	WA	PANGBORN-MEM_727825S
EPE	TX	EL-PASO-IAP_722700S

GCPD	WA	MOSES-LAKE-GRANT-CO-AP_727827S
IPCO	ID	BOISE-AIR-TERMINAL_726810S
		BURLEY-MUNI-AP_725867S
NEVP	NV	LAS-VEGAS-MCCARRAN-IAP_723860S
NWMT	MT	GREAT-FALLS-IAP_727750S
PACE	ID	IDAHO-FALLS-FANNING-FIELD_725785S
	UT	SALT-LAKE-CITY-IAP_725720S
	WY	JACKSON-HOLE_725776S
PACW	OR	MEDFORD-ROGUE-VALLEY-IAP_725970S
		PORTLAND-IAP_726980S
PGE	OR	PORTLAND-IAP_726980S
PNM	NM	ALBUQUERQUE-IAP_723650S
		SANTA-FE-CO-MUNI-AP_723656S
PSCO	CO	COLORADO-SPRINGS-MUNI-AP_724660S
		DENVER-IAP_725650S
PSEI	WA	SEATTLE-BOEING-FIELD_727935S
SCL	WA	SEATTLE-BOEING-FIELD_727935S
SPPC	NV	RENO-TAHOE-IAP_724880S
SRP	AZ	PHOENIX-SKY-HARBOR-IAP_722780S
TEPC	AZ	TUCSON-IAP_722740S
TPWR	WA	SEATTLE-TACOMA-IAP_727930S
WACM	CO	COLORADO-SPRINGS-MUNI-AP_724660S
	SD	SPEARFISH-CLYDE-ICE_726605S
WALC	AZ	CHANDLER-WILLIAMS-AFB_722786S
WAUW	MT	GREAT-FALLS-IAP_727750S

Appendix C Building Electrification Load Profiles

To create the building electrification profiles that were used in the load forecast for the production simulation modeling, parametric runs of building simulations were performed and aggregated up to a statewide level. This approach provides a rough approximation and does not fully capture the actual diversity of building stock or behavioral patterns; however, it generates the macro-level signals that are consistent with this future. In general, there will be higher loads from heat pump space heating in the winter, and those loads will be greater on colder days, and at certain times of day. There are several large research efforts currently in progress that aim to better characterize future building electrification hourly end use load profiles[51],[52],[53]. As electrification end-use data that is reflective of diverse building stock and occupant behavior becomes available, it should be used in place of this data.

To support this analysis, parametric building simulation results from CBECC-Res and CBECC-Com were provided by Bruce Wilcox and NORESCO, respectively. Representative building types with baseline mixed fuel and all-electric equipment packages were run in all 16 Climate Zones, in the CTZ22 weather year.

C.1 Residential Building Simulations

For residential building simulations, each prototype building (2100 sqft single family, 2700 sqft, and 6960 sqft low-rise multifamily) was run with both the 2019 mixed fuel baseline and 2019 all-electric baseline for all 16 climate zones, for a total of (3 x 2 x 16) 96 simulations. To determine a building electrification profile for a given building type and climate zone, the differences in hourly electricity consumption profiles

[51] CEC Commercial End-Use Survey (CEUS). https://www.energy.ca.gov/data-reports/surveys/california-commercial-end-use-survey

[52] CEC 2019 Residential Appliance Saturation Survey. https://www.energy.ca.gov/data-reports/surveys/2019-residental-appliance-saturation-study

[53] NREL End-Use Load Profiles for the U.S. Building Stock. https://www.nrel.gov/buildings/end-use-load-profiles.html

between the mixed fuel and all-electric package were taken for space heating, water heating, and appliance/cooking end-use categories.

To aggregate these simulations up to a statewide level, building stock data by utility, building size, and climate zone was taken from the 2009 California Residential Appliance Saturation Survey[54]. Since RASS reports building size on a more granular level, it was assumed that all single-family homes under 2,000sqft and townhouses between 1,250 sqft and 2,000 sqft are represented by the CBECC-Res 2100 sqft prototype building. All single-family homes and townhouses greater than 2,000 sqft were assumed to be represented by the CBECC-Res 2700 sqft prototype building. All Apt Condos and townhouses under 1,250 sqft were assumed to be represented by one unit of the 8-unit 6,960 sqft low-rise multifamily building.

This was aggregated up to the utility level, with each prototype building from one of the 16 climate zones representing a percentage of each utility's residential building stock. The percentages by utility and climate zone were used to create a normalized, weighted-average end-use profile for the following end use categories: space heating, water heating, and appliance/cooking.

Since building simulations do not an occupancy schedule that is diversified on the same level as the state, using direct hourly results would create building electrification end use loads that are likely too volatile. To correct this, a "diversified" end use shape was created using rolling averages of the residential hourly end use profiles. For space heating, a 3-hour rolling average was taken. For water heating, a 5-hour rolling average was taken. For cooking and clothes drying month-hour averages were taken due to the high level of coincidence in the building simulations, and relative weather-neutrality of these end use loads.

These normalized end use loads were then multiplied by annual load forecasts by end use and utility from E3's pathways models and added to the load forecast in the production simulation model.

[54] 2009 California Residential Appliance Saturation Survey: **https://ww2.energy.ca.gov/appliances/rass/previous_rass.html**

C.2 Non-Residential Building Simulations

For non-residential buildings, the prototype buildings are not as readily available, so a deeper building stock analysis was performed by NROESCO. A subset of seven prototypes was chosen from the full complement of 16 prototypes. These seven prototypes represent nearly 80%[55] of the projected construction floor area in 2020 and, for the purpose of this analysis, could be considered representative of the California new construction stock. Table 26Table 26. Non-Residential prototype buildings selected for this analysis. shows the list of prototypes used in the analysis.

Table 26. Non-Residential prototype buildings selected for this analysis.

Prototype	Floor Area, sf	Number of Stories
Large Office	498,640	12
Small Office	5,500	1
Medium Office	53,630	3
Medium Retail	24,570	1
Small School	24,415	1
Warehouse	52,050	1
High-rise Residential	94,100	10

Table 27shows the standard or 'baseline' HVAC system types and the corresponding all-electric system types selected for the prototypes. In most cases, the heating source was changed from a gas furnace or a gas boiler or either a heat pump or electric resistance heat. The High-rise Apartment and Warehouse prototypes have multiple system types serving different zones in the building. For the High-rise Apartment, the WSHP system was used in the all-electric scenario and it serves all zones. For the Warehouse, the two baseline systems were replaced with all-electric counterparts serving the same zones as in the baseline.

[55] 2019 Impacts Analysis Final Report. Retrieved from https://ww2.energy.ca.gov/title24/2019standards/post_adoption/documents/2019_Impact_Analysis_Final_Report_2018-06-29.pdf

Table 27. HVAC system type selection for baseline and all-electric cases

Prototype	Baseline			All-electric		
	System Type*	Heating Source	Cooling Source	System Type	Heating Source	Cooling Source
Small Office	SZAC	Gas furnace	DX	SZHP	HP	HP
Small School	SZVAV	Gas furnace	DX	PVAV	Electric Reheat	DX
Medium Office	PVAV	Gas Boiler	DX	PVAV	Electric Reheat	DX
High-Rise Residential	FPFC	Gas Boiler	Chiller	WSHP	Electric Boiler	Cooling Tower
	VAV	Gas Boiler	Chiller			
Large Office	PVAV	Gas Boiler	DX	PVAV	Electric Reheat	Chiller
Warehouse	SZVAVAC	Gas furnace	DX	SZVAVHP	HP	HP
	HeatVent	Gas furnace	None	HeatVent	Electric Res.	None
Medium Retail	SZVAVAC	Gas furnace	DX	SZVAVHP	HP	HP

*SZ=single zone, AC=air conditioner, DX=direct expansion, HP=heat pump, PVAV=packaged variable air volume, FPFC=four pipe fan coil, WSHP=water source heat pump

New construction projected floor area was provided by the California Energy Commission for the 2019 Impacts Analysis. The projected floor area in 2020 was used to determine the weight for each of the seven prototypes in the 16 climate zones. This weight was then applied across the prototypes to calculate the aggregate climate zone hourly load profiles. Note that the projected floor area of building types not used in the analysis was discarded and the relative weights were adjusted amongst the selected prototypes so that they sum to 1.00.

Table 28. Building Stock adjusted weights (%) by climate zone for selected prototypes

Climate Zone	Small Office	Medium Retail	Warehouse	Small School	Large Office*	Hi-Rise Res.	TOTAL
1	0.04	0.07	0.03	0.06	0.05	0.02	0.27
2	0.17	0.59	0.40	0.27	0.69	0.34	2.47
3	0.57	2.62	2.37	1.00	4.60	1.82	13.00
4	0.39	1.42	0.90	0.62	1.56	0.83	5.71
5	0.08	0.28	0.17	0.12	0.30	0.16	1.11
6	0.52	2.20	1.80	0.66	2.90	0.73	8.82
7	0.70	1.36	0.76	0.71	1.46	0.85	5.84
8	0.73	3.17	2.56	0.97	4.24	1.11	12.79
9	0.71	3.35	2.74	0.98	5.73	2.24	15.76
10	0.82	2.54	2.18	1.37	1.44	0.91	9.26

11	0.23	0.54	0.53	0.36	0.27	0.16	2.09
12	1.24	2.92	2.50	1.46	2.99	1.30	12.41
13	0.50	1.19	1.02	0.79	0.52	0.30	4.32
14	0.13	0.50	0.43	0.25	0.36	0.16	1.84
15	0.18	0.44	0.48	0.25	0.18	0.10	1.63
16	0.18	0.64	0.44	0.27	0.83	0.31	2.67
TOTAL	7.21	23.83	19.32	10.15	28.13	11.36	100.00

*Large office building type weight split equally between Large and Medium Office prototypes (per Impacts Analysis 2019)

For each model, the following hourly (8760) outputs were generated: electricity and natural gas total site consumption, and heating, interior and exterior equipment, and service hot water end-use consumption by fuel type. For each output, the hourly value was weighted, then summed across prototypes in a given climate zone, and finally normalized to the total annual consumption.

Similar to residential buildings, the normalized climate zone-level, non-residential end-use profiles were mapped to specific utilities using the conversion tables between climate zone and forecast climate zone. Utility-specific normalized end-use profiles were again found to have coincident occupancy schedules that are not reflective of a diverse building stock. To correct this, for space heating a 5-hour rolling average was taken of the hourly end-use profiles. For water heating, a 5-hour rolling average was also taken.

These normalized end use loads were then multiplied by annual load forecasts by end use and utility from E3's pathways models and added to the load forecast in the production simulation model.

C.3 Building Electrification Load Profile Results

The resulting normalized and 2050 statewide aggregated building electrification profiles are displayed below.

Figure 73. Normalized Statewide Building Electrification Load Profiles by End Use

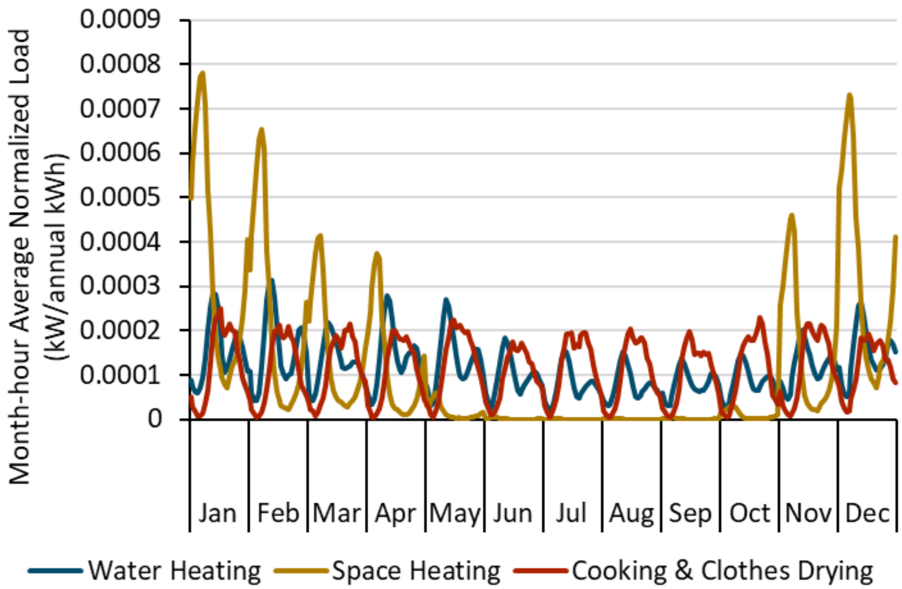
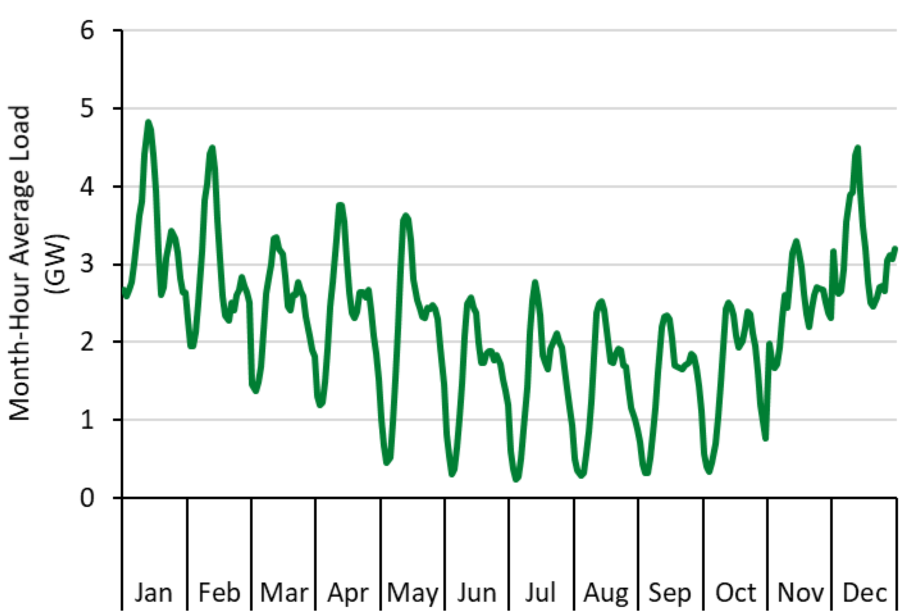


Figure 74. 2050 aggregated statewide building electrification load profile used for production simulation modeling in 2022 TDV analysis



Appendix D Electric Vehicle Load Forecast Methodology

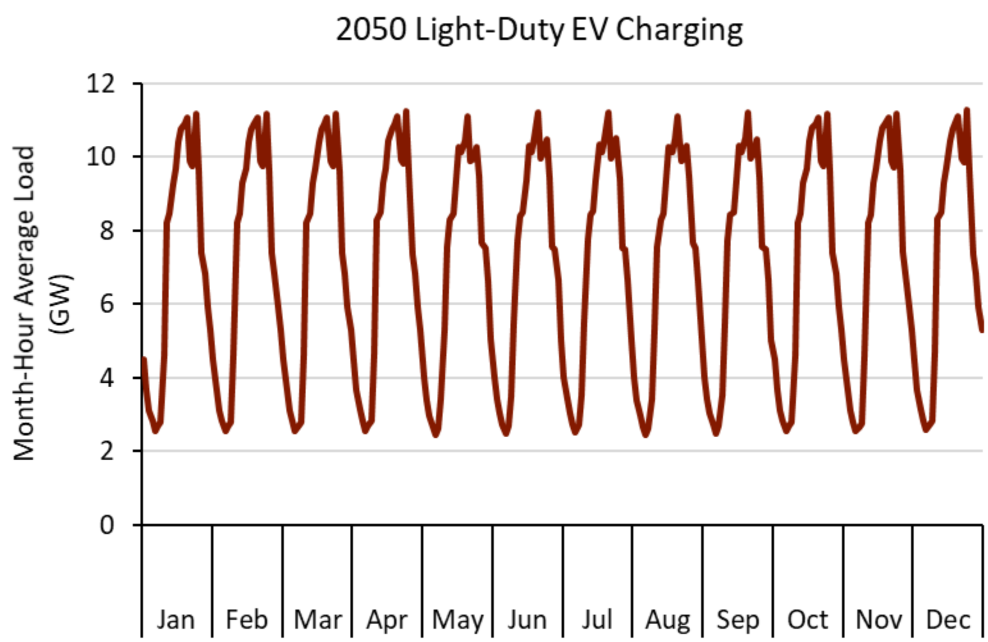
Transportation electrification is a key element for decarbonizing the transportation sector. As higher penetration of renewable generation drives down the carbon intensity of the electricity supply, transitioning from conventional fossil fuel-powered vehicles to electric vehicles can play a major role in meeting economy-wide GHG-reduction goals for California. Along with carbon mitigation, vehicle electrification represents a large and fundamentally different load shape on the grid, altering the magnitude and timing of electricity costs, thus necessitating their inclusion in the TDVs. Aggregated regionally specific load shapes for personal light-duty electric vehicles were produced in E3's stochastic electric vehicle load simulation tool and then scaled by PATHWAYS and EIA AEO EV adoption forecasts for California and other WECC BAAs, respectively. Due to the relative market maturity of personal light-duty EVs versus medium/heavy-duty, shared, and autonomous EVs, only the former was included in the load forecasting for this TDV update. These emerging vehicle classes and technologies should be revisited in the next update.

E3's stochastic electric vehicle load simulation tool generates an hourly electric load from charging electric vehicles (EVs) for a population of drivers. The model uses detailed trip data to simulate driving and charging behavior of thousands of drivers under different EV and charging access scenarios. Driving and charging simulations for personal light duty vehicles are performed for 24 customer types – four different EV types by six characterizations of charger access – to generate a normalized load shape for each customer type. These normalized load shapes are then scaled by the number of drivers in the population that fall into each customer type. The final load shape therefore captures the diversity of driving behavior, charging access, and EV type adoption across a population.

In this analysis, distinct regional electric vehicle load shapes are created using inputs specific to California, Pacific Northwest, Desert Southwest, and Mountain West to capture geographical variation in behavior. California load shapes were scaled to PATHWAYS forecast of annual EV load, maintaining consistency with other load and distributed energy resource forecasts used in the TDVs. For EV demand outside of

California, load shapes were scaled to 2019 EIA AEO annual EV load forecasts by state, which were downscaled by BAA load share to match PLEXOS zonal definitions. As the AEO forecasts only cover the US, EV shapes were not created for non-US WECC BAAs (AESO, BCHA, and CFE).

Figure 75. 2050 aggregated statewide transportation electrification loads used in production simulation modeling in 2022 TDV analysis



Appendix E Renewable Generation Profiles

E3 collected historical weather data to more accurately model hourly renewable generation profiles. Table 29 below shows the historical months that make up the CTZ weather year. Historical weather data was collected for these historical months.

Table 29: Historical Months of the CTZ Weather Year

CTZ Weather Year	
Month	**Year**
1	2004
2	2008
3	2014
4	2011
5	2017
6	2013
7	2011
8	2008
9	2006
10	2012
11	2005
12	2004

E.1 Hourly Wind Generation Profiles

In creating wind generation profiles for this update's PLEXOS production simulation modeling, E3 was able to leverage a model and WECC-wide database previously developed by E3. This database contains the location and characteristics (capacity, hub height, turbine model) of existing and potential wind turbines throughout the Western Interconnection. While previous applications of this model and database utilized the rich database of wind data in NREL's Wind Toolkit (WTK), the new CTZ22 weather year required simulating wind profiles using historical weather outside of the WTK data's available years.

For each location for each historical month-year in the CTZ22 weather year E3 simulated hourly generation profiles. Wind profile creation requires special weather data that combines observed historical weather data and climate models to model wind speeds, direction, etc. at a specific location and hub height. The following sources of these data were required to model the full historical timeframe characterized by the CTZ22 weather:

+ NREL Western Wind: four months from years 2004-2006
+ NREL Wind Toolkit: six months from years 2008-2013
+ Renewables Ninja: two months from years 2014-2017

Each source of turbine weather differs in methodology and underlying data, requiring adjustments for consistency for a given turbine across the entire CTZ22 weather year. The resulting profiles are aggregated by the renewable resource regions defined in PLEXOS and mapped to the specific generators within that region.

E.2 Hourly Utility-scale Solar PV Generation Profiles

Similarly, E3 leveraged an existing database with location and characteristics (capacity, tilt, mount type, technology) of existing utility-scale solar PV arrays. Using NREL's System Advisor Model (SAM) software, E3 simulated hourly generation profiles for each location for each historical month-year in the CTZ22. This historical weather was available for all of the CTZ22 month-years in the NREL National Solar Radiation Database (NSRDB). The resulting profiles are aggregated by the renewable resource regions defined in PLEXOS and mapped to the specific generators within that region.

E.3 Hourly Distributed Generation (DG) Solar PV Generation Profiles

Creating generation profiles for DG PV used a similar approach to producing utility-scale PV profiles with several key changes to account for differences in technology and geographic distribution. Whereas the utility-scale solar and wind processes start off with a database of large individual units, such an approach is impractical for the thousands of small DG PV systems in each zone. Instead, E3 produced CTZ22 weather-matched DG PV profiles for five azimuths for each county centroid in the Western Interconnection, setting the system tilt angle to the latitude. For each county, the five profiles with azimuths from 90 degrees (East-facing) to 270 degrees (West-facing) were weighted by the distribution in LBNL's Tracking the Sun dataset, accounting for the frequent limitations of DG PV orientation due to roof characteristics, shading, etc. The resulting county-level profiles were weighted into BAA profiles with installation data from 2017 EIA Form 861 - Net Metering PV Capacity. For California, annual DG PV projections came from PATHWAYS, and the WECC Common Case DG PV Forecast was used to scale profiles outside of California.