2024 ANNUAL REPORT OF THE INDEPENDENT EMISSIONS MARKET ADVISORY COMMITTEE

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Introduction

Meredith Fowlie and Danny Cullenward

Since its formation in 2018, the Independent Emissions Market Advisory Committee (IEMAC) has been tasked with reporting annually to the California Air Resources Board (CARB) and the Joint Legislative Committee on Climate Change Policies on the environmental and economic performance of California's carbon market. The IEMAC's members include five experts on greenhouse (GHG) emissions markets who were appointed by the Governor (three members), the Senate Rules Committee (one member), and the Speaker of the Assembly (one member), along with a non-voting representative from the Legislative Analyst's Office.

This seventh annual IEMAC report comes at a pivotal time.

First and foremost, California is grappling with the impacts of a changing climate, most visibly with the tragic wildfires in the greater Los Angeles area. Extreme heat, prolonged droughts, rising sea levels, and escalating wildfire risks are threatening the health, safety, and well-being of Californians across the state. The costs of adapting to climate change are manifesting in the form of increased insurance premiums and higher utility bills. For households with limited resources, these impacts are particularly acute.

Second, the Trump administration is making significant changes to federal climate and energy policies. These changes will almost certainly slow the flow of investment into clean energy innovation and climate change mitigation. State-level policies can provide critical support to sustain some momentum behind these investments, but these policies must be balanced against mounting affordability concerns. Energy costs are of particular concern in California, where retail gasoline and electricity prices are high and increasingly out of line with the rest of the country.

Third, the California legislature has begun deliberating the future of the cap-and-trade program. This program was initially authorized by AB 32 (Stat. 2006, Ch. 488) and extended through 2030 by AB 398 (Stat. 2017, Ch. 135). Clarifying the program's post-2030 future is particularly important now to encourage cost-effective emissions reductions and provide certainty to market participants, who are making long-term investment decisions that will be affected by the program's evolution. Re-authorization will also generate revenues from allowance auctions that can be strategically deployed to alleviate affordability concerns and finance climate initiatives.

The cap-and-trade reauthorization process presents an opportunity to review the program's design and evaluate potential improvements. This year's IEMAC report was written with this discussion in mind. Each chapter provides a foundational review of a key market design element or consideration. While the chapters focus on individual program components, it is important to recognize how these elements interact within the broader carbon market system. Changes to one aspect can have significant implications for other parts of the programs. These interactions, while important to consider, should not deter needed program reforms. Throughout the report, we highlight interactions that warrant attention.

Chapter 1. Affordability

California's cap-and-trade program has a critical role to play in providing economic incentives to invest in cost-effective GHG reductions across the economy. At the same time, higher GHG allowance prices induced by a tighter cap would put upward pressure on fossil fuel energy prices, raising concerns around the affordability of climate action. Unlike other factors driving retail energy price increases—such as rising expenditures on wildfire mitigation in the electricity sector or fluctuations in oil and natural gas prices in the transportation and building sectors—carbon pricing generates revenues for the state. These revenues can be leveraged to offset affordability impacts and assist California households in reducing their reliance on fossil fuels.

This chapter begins with an overview of energy affordability concerns in California. We assess the extent to which California's carbon price has impacted consumer energy prices and expenditures. We show that California carbon pricing has played a very small role in driving retail electricity price increases because the California electricity grid is not very carbon intensive (and getting cleaner by the year). We estimate that current carbon prices increase gasoline costs by approximately 26 cents per gallon and natural gas costs by approximately 18 cents per therm (holding other factors constant). Impacts on natural gas and gasoline prices are economically significant, though environmental programs are not the most significant driver of prices. Furthermore, both price estimates are well below EPA estimates of the climate costs per unit of gasoline and natural gas consumption, respectively.

As noted above, energy cost increases induced by carbon pricing generate revenues for the state that accrue to the Greenhouse Gas Reduction Fund and to fund a bi-annual "climate credit" paid to all utility customers. The intention of cap and trade is to deliver economically efficient emissions reductions, not to generate revenue. However, the associated revenues and how they are used can contribute to meeting the state's climate policy goals. The utility dividends could be restructured to reduce retail electricity prices and target those households most impacted by high utility bills. A growing share of GHG allowance revenues come from the transportation sector. Some of these revenues could be used to ease the burden of transportation-related costs, while at the same time accelerating the transition towards more sustainable energy alternatives.

Chapter 2. Cost containment

This chapter underscores the importance of cost containment in the design and implementation of California's climate policies. We begin by discussing the role that a well-designed GHG cap-and-trade program can play in managing the costs of reducing

GHG emissions in California. We highlight some important climate policy design trade-offs that arise when companion policies - such as clean technology mandates and subsidy programs- are used to support specific GHG abatement strategies. While these prescriptive policies can reduce GHG allowance prices, they can also drive up overall GHG abatement costs if the mandated measures are relatively expensive. Put differently, a greater reliance on the GHG cap-and-trade program will increase carbon prices, but it will also encourage more cost-effective mitigation strategies, ultimately lowering overall costs.

The second part of the chapter surveys evidence on current and proposed companion climate policies in California. This available evidence indicates that some of California's prescriptive policies, including some clean technology subsidies, deliver GHG reductions at a relatively high cost. Given mounting concerns around affordability (see Chapter 1), it will be important to ensure that prescriptive regulations are implemented in a way that aligns with cost containment objectives along with other policy goals.

Chapter 3. Allowance allocation

The purpose of this chapter is to describe how allowances are distributed in the cap-and-trade program, for what purpose, and with what approximate financial value. These details matter because allowance distribution decisions transfer billions of dollars in value to recipients, including substantial economic benefits to utility ratepayers in the current program.

Altogether, the value of allowances and carbon offsets issued each year in the program is approaching $10 billion per year. This number is substantially higher than the annual revenues collected by the Greenhouse Gas Reduction Fund because more than half of the allowances are freely allocated. About 45% of allowances are sold to quarterly auctions to generate revenue for the Greenhouse Gas Reduction Fund; about 37% are freely allocated to utilities for the purpose of ratepayer protection, with about 25% going to electric utilities and 12% to gas utilities; and about 13% are freely allocated to industrial emitters to address competitiveness concerns, mostly to the oil and gas and cement industries.

The chapter concludes with options for how the distribution of allowances could be modified in the future, along with the tradeoffs involved. Policymakers may wish to consider these choices as current program regulations establish allowance distributions only through 2030 and will need to be updated in the design of the post-2030 program.

Chapter 4. Market design

California's overall approach to climate mitigation policy features a mix of sector-specific regulations that interact with the cap-and-trade program. While the cap-and-trade program is particularly effective at producing low-cost emission reductions, much of the work in reducing emissions to date has come from sector-specific regulations.

As discussed in previous chapters, clarifying the cap-and-trade program's future and designing it to contribute more to the state's climate policy portfolio can improve overall cost-effectiveness. Because the state will continue to rely on a mix of policy instruments, however, it is important to design the cap-and-trade program in a manner that works effectively with other climate strategies. That is not always the case today. When local governments, private firms, or sector-specific regulations succeed in reducing pollution, they also reduce demand for allowances and lower carbon prices. This can reduce the effectiveness of the cap-and-trade program and reduce Greenhouse Gas Reduction Fund revenues.

To improve the interaction between the cap-and-trade program and other policy instruments, policymakers could introduce an emissions containment reserve that would automatically reduce allowance supplies when market prices are low. The IEMAC has previously recommended the development of such a program feature in earlier reports. This chapter reviews how an emissions containment reserve could be designed and how its presence would have increased Greenhouse Gas Reduction Fund revenues over the last few years.

Chapter 5. Environmental Justice

Decades of regulations targeting local air pollution directly have failed to eliminate local pollution exposure inequities in California (and across the country). The Environmental Justice Advisory Committee (EJAC) at the California Air Resources Board (CARB) has raised numerous concerns about the GHG cap-and-trade program over the years. More recently, EJAC has issued a resolution including a number of recommendations to reform the GHG cap-and-trade program.

EJAC has explicitly asked to be included in all conversations around this resolution as full partners so that EJ groups can articulate concerns and priorities as negotiations proceed. Thus, this chapter does not endeavor to make any policy design recommendations. Instead, the chapter acknowledges the important concerns of environmental justice groups around local air pollution in their communities. It offers some observations around how some of the EJAC recommendations could interact with cap-and-trade program design issues discussed elsewhere in this report. Finally, it underscores the importance of engaging directly with EJAC in discussions of EJAC resolutions.

In a public comment, Dr. Catherine Garoupa, co-chair of the EJAC, expressed frustration with this approach:

Overall, despite acknowledging that the "EJAC has asked to be included in conversations around these recommendations as full partners so that EJ groups can articulate concerns and priorities as negotiations proceed" - the IEMAC did exactly the opposite by parsing out which EJAC recommendations to consider, then proceeded to make analytical conclusions that are far outside of the IEMAC members' areas of expertise.

Dr. Garoupa goes on to request that the IEMAC *"omit the chapter in its entirety and defer all comments or questions about environmental justice concerns to the EJAC".*

IEMAC took this request into serious consideration. Revisions were made in light of this comment (and others received during the public comment period). However, we ultimately decided against omitting this chapter. An IEMAC report that aims to provide lawmakers with an overview of key GHG carbon market design elements and issues should include some discussion of concerns that EJAC has raised. With regard to our decision to focus on a subset of EJAC recommendations, IEMAC is tasked with advising on issues that directly pertain to the environmental and economic performance of California's carbon market. With some reservation, we focus our discussion on the subset of EJAC resolutions that fall within our committee expertise.

Any serious discussion of the EJAC resolution will require a serious consideration of how EJAC propositions could impact carbon market operations and outcomes. The chapter offers some IEMAC perspectives on these potential impacts which we hope will be informative when legislators consult directly with EJAC on these issues.

Chapter 6. Carbon Management

Carbon management is an issue of growing interest among California policymakers and regulators. With this chapter, IEMAC aims to situate various carbon management strategies – carbon capture and storage (CCS) and carbon dioxide removal (CDR) - within the carbon market discussion, and surface considerations for policymakers as they determine the future shape and priorities of California's cap- and-trade program.

California will eventually need to decide if it wants to incorporate carbon management within the GHG cap-and-trade program and if so, then how. IEMAC surfaces many of the considerations that would need to go into this decision including emissions accounting, monitoring, reporting and verification, treatment of reversals, financial assurances, and others.

The Legislature has engaged with many of these issues in SB 905. But until the SB 905 regulations are complete, it is difficult to assess an appropriate or preferred role of CCS or CDR within the cap-and-trade program. As such, the robust implementation of SB 905 is a priority. The current cap-and-trade rule is ambiguous with respect to captured carbon; clarification would require SB 905 to be implemented.

There is less existing guidance from the Legislature on CDR. If the Legislature provides guidance to incorporate CDR into the cap-and-trade program – a process which would also be reliant on SB 905 implementation - it should direct CARB to count removal of emissions separately from emission reductions, and ensure that the inclusion of removal credits does not increase the overall number of compliance instruments in the program.

Chapter 7. Offsets

California has a large carbon offsets program, with about 80% of offset credits going to forest projects across the United States. Carbon offsets expand the supply of compliance instruments in the program, which reduces market prices and lowers compliance costs. By allowing regulated emitters to comply with program rules by purchasing offset credits, rather than buying allowances at auction, the program also functions as a funding mechanism that transfers resources from regulated emitters to offset market participants, including Tribal parties.

Because the academic literature has identified significant concerns with the performance of the offsets program, this chapter reviews potential reforms that include modifications to the design of the offset program as well as replacement with an alternative funding mechanism that would support investment in natural and working lands. For each potential option, the chapter evaluates tradeoffs and identifies strategies for preserving investment in natural and working lands as well as the interests of Tribal parties.

Limits on offset use were established by regulation through 2020 and by statute through 2030. The Legislature has not yet specified a limit on post-2030 offset use.

Chapter 1. Assessing the Affordability Implications of California's GHG Cap and Trade Program[1]

Meredith Fowlie and Dallas Burtraw

California is grappling with the impacts of a changing climate. Extreme heat, prolonged droughts, rising sea levels, and escalating wildfire risks are threatening the health, safety, and well-being of Californians across the state. The costs of adapting to climate change are starting to manifest in the form of increased insurance premiums and higher utility bills. For households with limited resources, these impacts can be particularly acute.

Reauthorization of the GHG cap-and-trade program would affirm California's commitment to reducing statewide GHG reductions and could inscribe a tighter GHG emissions cap to provide stronger incentives to invest in GHG abatement. At the same time, a tighter cap could increase compliance costs for industrial producers which get passed through to customers. Upward pressure on consumer energy prices raises concerns around the "affordability" of climate action. It is important to note that, in contrast to other factors that can drive retail energy price increases (such as increased spending on wildfire mitigation in the electricity sector, or hard-to-predict oil and natural gas price fluctuations in the transportation and building sectors), **GHG allowance price increases are relatively predictable and generate revenues for the state of California. These revenues can be used to offset affordability impacts and help California households reduce their reliance on fossil fuels.**

This chapter begins with an overview of energy affordability concerns in California. We assess the extent to which California's carbon prices have impacted consumer energy prices and expenditures, starting with electricity. We show that **California's cap-and-trade program has not been a significant driver of retail electricity price increases.** Using data from 2023, we estimate that carbon pricing increased retail PG&E electricity rates by approximately 4%. These electricity price impacts have largely been offset by a bi-annual "climate credit" that sends carbon revenues back to utility consumers.

The consumer price impacts of carbon pricing in California have been more significant for natural gas and gasoline, in part because these fuels are more carbon-intensive. The costs of complying with the cap-and-trade program increased retail natural gas prices by an estimated 8% in 2023. This carbon price increase was largely offset by a "climate credit" on consumers' utility bills. We estimate that carbon pricing increased 2023 gasoline prices by approximately **26 cents per gallon** (this assumes complete cost pass through to consumers). Although carbon pricing does put upward pressure on consumer fuel

[1] For outstanding research assistance, we thank Thor Larson and Kaixin Wang.

prices, **retail gasoline and natural gas prices are still *lower* than estimated social marginal costs of gas and natural gas consumption, respectively.**

We survey recent carbon market modeling exercises that forecast carbon price increases under alternative market reforms. While projections of higher carbon prices would lead to higher retail natural gas and gasoline prices (all else equal), the impacts of these higher energy prices on household energy expenditures will diminish as households reduce their reliance on fossil fuels to meet their energy needs. For this future to be realized, however, we need to fix retail electricity price structures and give customers the right signals (1) for electricity consumption and (2) for fuel substitution. **Importantly, higher carbon prices generate carbon market revenues which can be used to offset energy affordability impacts on energy consumers while preserving the incentive to reduce reliance on more carbon intensive fuels**. Revenue generation is not the central purpose of carbon pricing, which is primarily designed to deliver economically efficient emissions reductions. However, carbon market revenues can be used to ease the burden of energy price increases, while at the same time accelerating the transition towards more sustainable energy alternatives.

Context: Rising Consumer Costs in California

Overall consumer prices have increased [by more than 20%](#) across the nation since 2020. Retail energy prices have increased even faster in California. The charts below show how retail gasoline, natural gas, and electricity prices in the Bay Area of California are high and increasingly out of line with the rest of the country. Retail prices for other metropolitan areas of California show similar patterns.

Figure 1: Average Bay Area Retail Energy Prices

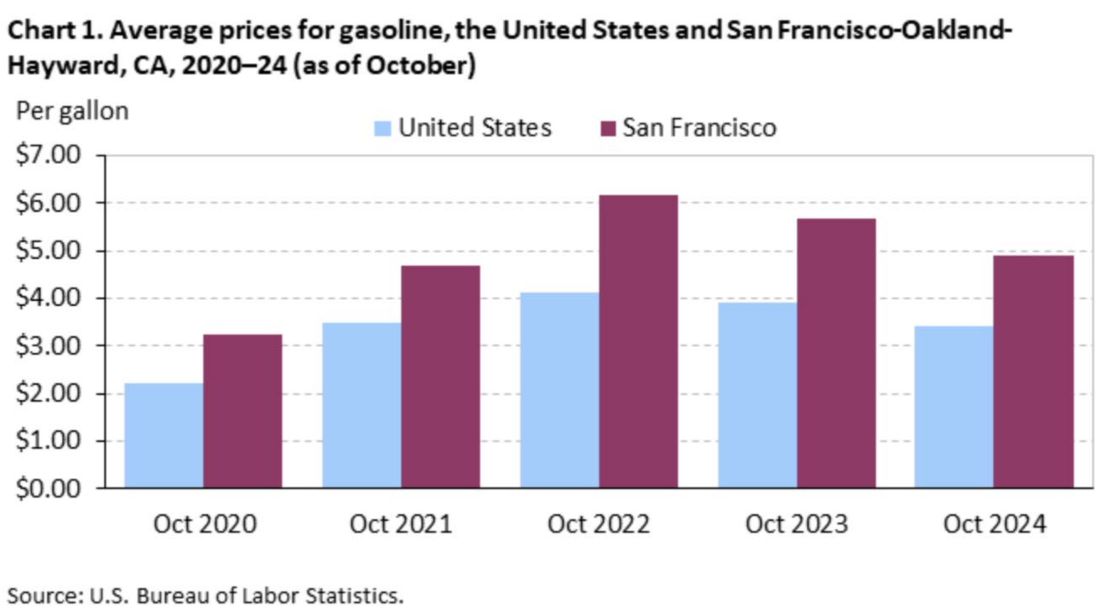
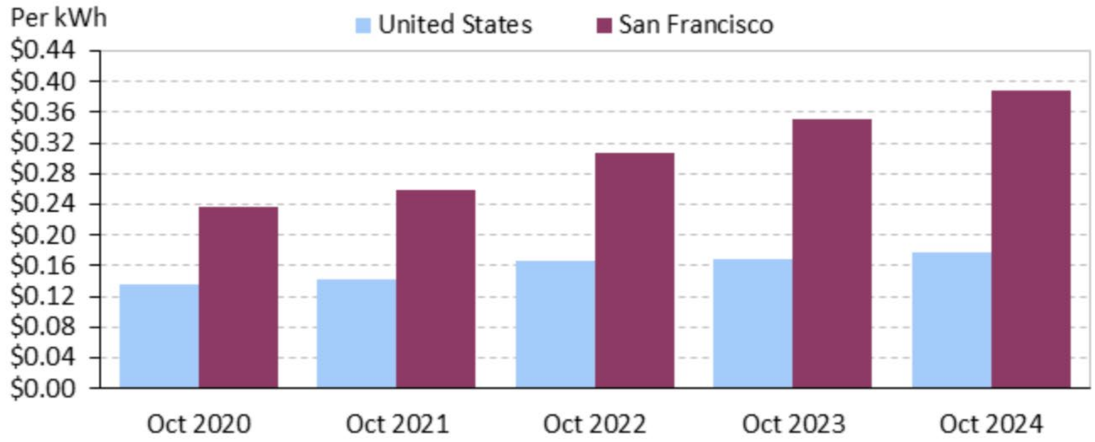
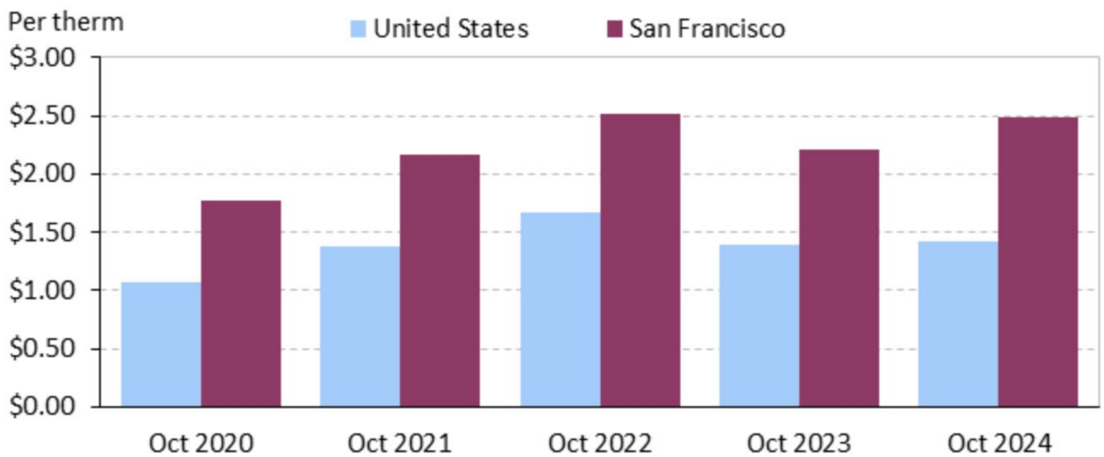


Chart 2. Average prices for electricity, the United States and San Francisco-Oakland-Hayward, CA, 2020–24 (as of October)



Source: U.S. Bureau of Labor Statistics.

Chart 3. Average prices for utility (piped) gas, the United States and San Francisco-Oakland-Hayward, CA, 2020–24 (as of October)

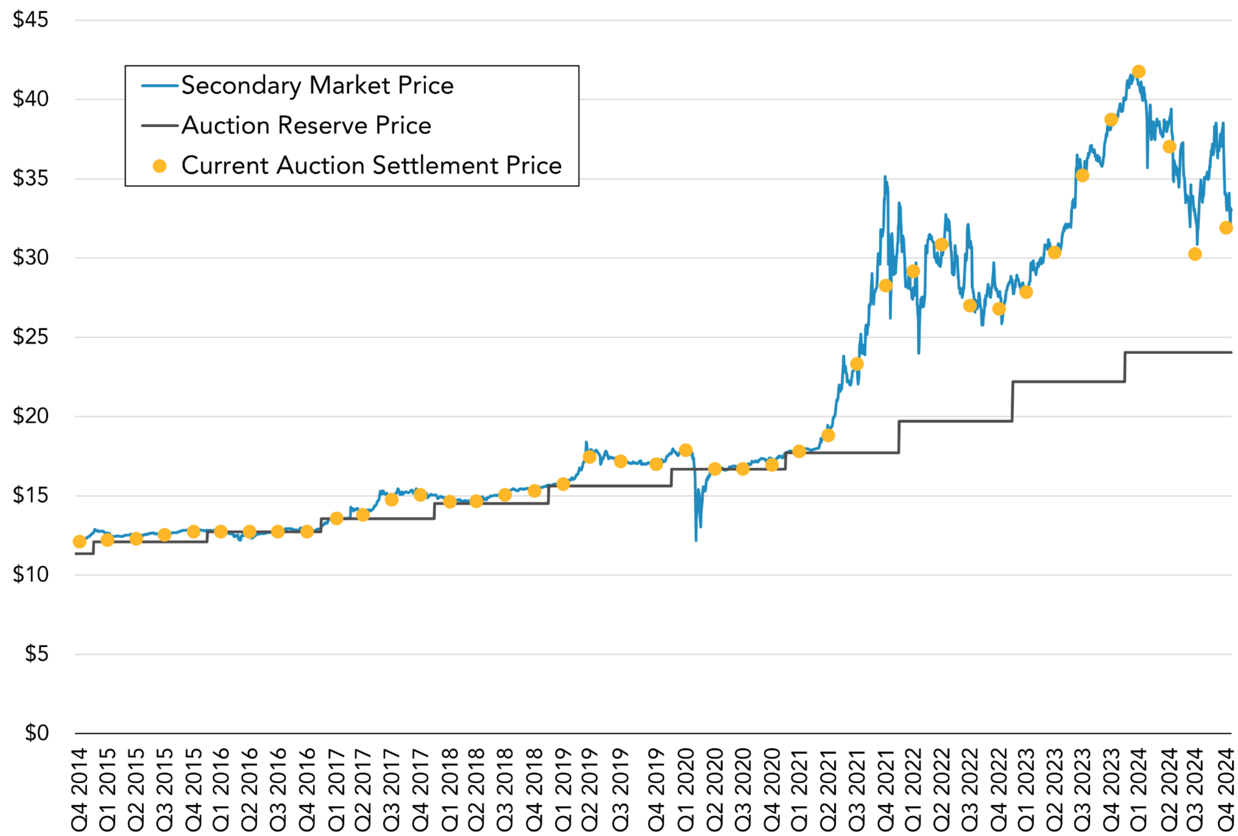


Source: U.S. Bureau of Labor Statistics.

Source: https://www.bls.gov/regions/west/news-release/averageenergyprices_sanfrancisco.htm

California GHG allowance prices have also been increasing since 2020. The graph below tracks the market price per ton of CO_2 over time. For the first ten years of the program, the carbon market clearing price was close to the floor price (the minimum price at which allowances can sell in the auction). Post-2020, the GHG allowance price has increased, presumably reflecting market expectations that future reforms to the cap-and-trade program will reduce GHG allowance supply.

Figure 2: California and Quebec Carbon Allowance Prices



Source: https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard

How have California carbon prices impacted California's retail energy prices?

If energy prices do not reflect the full social cost of energy production and consumption (including the climate change related damages), households and firms will not account for these costs in their consumption and investment choices. One important purpose of carbon pricing is to signal the climate-related damages in the price of fuels, goods, and services that are bought and sold throughout the economy so that these costs can be accounted for.

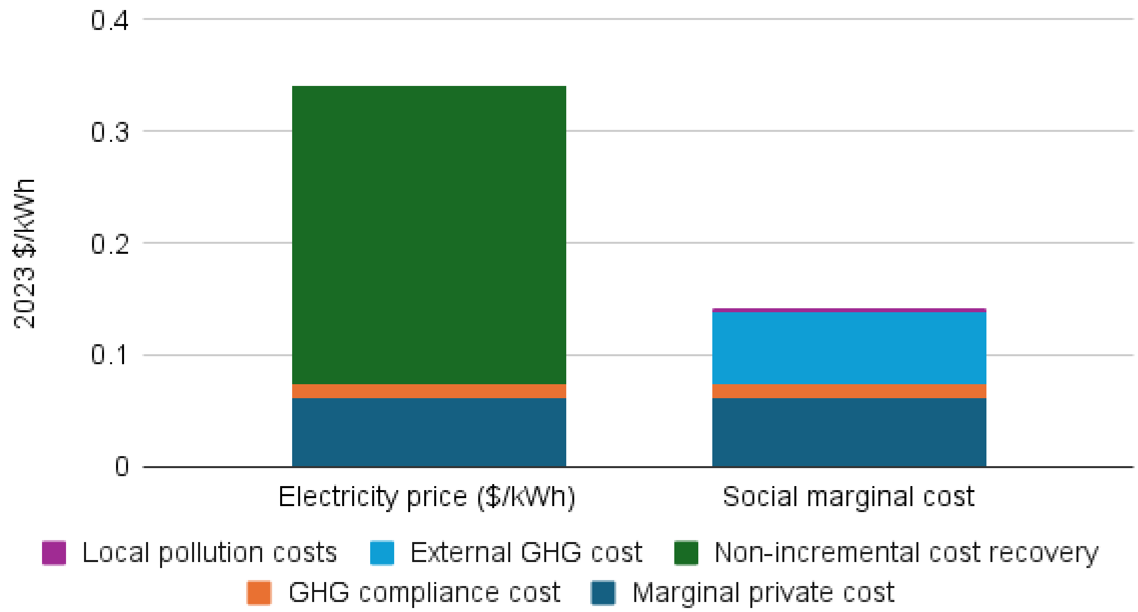
In theory, increasing consumer energy prices to better reflect the associated environmental damages will support more efficient investment decisions, consumption choices, and market outcomes. However, carbon pricing can lead to *less* efficient outcomes if retail energy prices are already set higher than the social marginal cost of energy consumption. This can happen, for example, if energy consumption is subject to other forms of taxation. It is, therefore, important to understand how carbon pricing will impact consumer energy prices, and how these retail energy prices compare against efficient energy price benchmarks.

In what follows, we use 2023 data on retail energy prices and the private marginal costs of energy consumption to coarsely assess the impacts of California's GHG allowance prices on retail residential energy prices. We then compare 2023 retail energy prices against estimates of the corresponding "social marginal cost" (SMC) of fuel consumption which serve as an efficient price benchmark. This SMC benchmark includes not only the private costs of producing an additional unit of energy (e.g. fuel costs, distribution costs, losses), but also "external" marginal costs that are not reflected in supplier costs (i.e. pollution damages). Comparing the energy prices consumers are paying for energy versus the social marginal cost helps put the California carbon price into perspective.

Carbon pricing impacts on retail electricity prices

We begin with an illustrative analysis of 2023 residential retail electricity prices, focusing on California's largest utility (PG&E). The bar to the left in the figure below decomposes the average retail electricity price paid by PG&E residential customers in 2023 into three estimated cost components:

Figure 3: 2023 Retail electricity price versus social marginal cost ($/kWh)



Marginal private (utility) costs: Utility marginal costs capture all of the variable costs incurred by the utility when electricity demand increases incrementally or "marginally". We estimate these marginal private costs using average hourly wholesale electricity prices in 2023. We adjust for distribution line losses using the same approach as Borenstein and Bushnell (2022). The navy-blue bar in the figure above corresponds to the average marginal cost across all hours in 2023.

GHG cap and trade compliance costs (orange bar) are estimated on a per kWh basis. Electricity generators in California must hold allowances to offset GHG emissions. This compliance obligation increases wholesale electricity prices when the marginal (i.e. price-setting) supplier is a fossil-fueled generator. To estimate the impact of these compliance costs on wholesale electricity prices in 2023, we multiply the average hourly marginal GHG intensity of electricity supply in 2023, adjusting for line losses, by the average California allowance price in 2023 ($33/ton CO2e). Using this approach, we estimate that complying with the GHG cap-and-trade program increased residential electricity prices by 1.3 cents per kWh (less than 5 percent of the retail rate)

Non-incremental costs (green bar) incurred in the power sector are primarily recovered via retail electricity prices. These include fixed capital investment costs in power system infrastructure, wildfire risk mitigation costs, clean technology incentives, etc. What distinguishes these utility costs from "marginal" costs is that they do not vary with marginal changes in electricity consumption. To estimate this cost component, we subtract marginal private costs (including compliance costs) from the average retail price. This fixed cost recovery component amounts to an estimated 78 percent of the retail rate.

Social marginal cost: Some of the costs caused by electricity generation are incurred by society but not borne by electricity suppliers or consumers. One important example: the climate costs associated with GHG emissions that are not reflected in the California GHG allowance price. To monetize these "external" climate damages, we use EPA's central estimate of the global climate costs per ton of CO2e emissions, $190 per metric ton. Because this significantly exceeds the 2023 California GHG allowance price, we estimate that a large share of climate damages is "external" to private cost calculations. In addition, fossil-fueled electricity generators contribute to local air quality problems that are not reflected in supplier costs. The externality costs associated with local air pollution from electricity generation depend not only on the marginal emissions intensity of electricity generation, but also on the air transport of emissions, downwind population densities, and health impacts. Incorporating both the assessed climate costs and local air pollution impacts, we estimate a 2023 social marginal cost of 14 cents/kWh.

Comparing the retail electricity price (left) against our estimated social marginal cost (right) in the graphic above implies that PG&E consumers are paying too much for their electricity (because electricity rates are used to recover revenues to cover non-incremental costs). This has broad efficiency implications for California's general climate policy portfolio which hinges on expanding electrification of transportation, buildings, and industry. Inefficiently high retail electricity prices slow progress on electrification. Because retail electricity rates already reflect a sizable effective charge for costs that are not associated with the incremental use of energy, *the carbon price might be understood to push electricity prices in the wrong direction*.

This retail electricity pricing regime also poses affordability challenges for lower income households who spend a relatively large share of income on utility bills. Currently, a portion of carbon revenues associated with electricity sector compliance with cap and trade are rebated to electricity consumers on an equal per-customer-account basis, adjusted according to the utility service territory, reflecting variations in the emissions intensity (tons CO2/MWh) of electricity consumed and the household level of electricity consumption. This is known as the "climate credit" that appears biannually on residential electricity bills. Although it helps address distributional concerns, it does not address the problems associated with too-high volumetric electricity prices.

To improve the efficiency of electricity pricing, the Air Resources Board should consider an alternative climate rebate design. GHG allowance revenues could be used to reduce *volumetric* (retail) electricity prices as this would move retail electricity prices closer to the social marginal cost, although that may require legislative action. Revenue recycling could also be restructured to address affordability concerns more directly. For example, per-household rebates could be eliminated and allowance revenues could instead be used to provide larger electricity price discounts for lower income households who are disproportionately impacted by higher electricity prices.

Carbon pricing impacts on retail natural gas prices

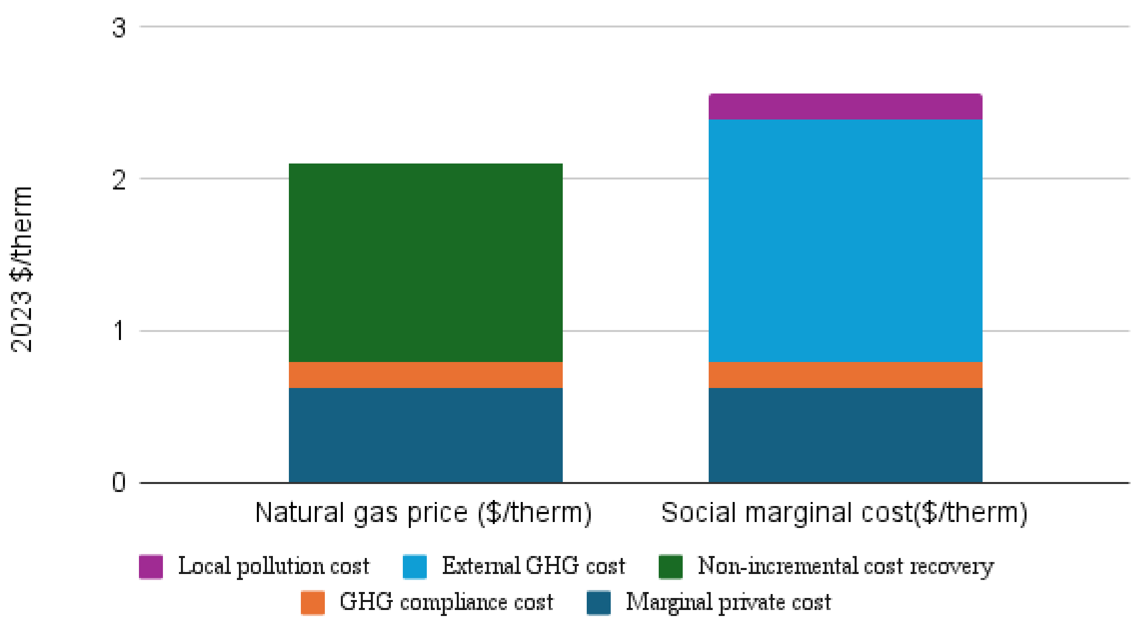
We conduct a similar analysis of California's retail natural gas prices, again focusing on 2023 PG&E rates and costs. These calculations are summarized in the graphic below.

Variable natural gas supply costs are calibrated based on 2023 citygate prices adjusted for loss (or LAUF) rates.

GHG cap and trade compliance costs: We estimate that California's carbon pricing raised retail natural gas prices in 2023 by approximately $0.18/therm, i.e. it contributed about 8% of the residential retail prices paid by households.

Non-incremental costs: Retail natural gas prices, like electricity prices, are set above the private marginal cost of supplying natural gas to recover non-incremental supply costs including the costs of building and maintaining the natural gas distribution system.

Figure 4: 2023 Natural gas price versus social marginal cost (2023$/therm



In contrast to electricity, retail natural gas rates in 2023 were significantly below the estimated social marginal cost of natural gas consumption. To calibrate our social marginal cost estimates for natural gas, we rely on standard measures of natural gas emissions intensity. We account for both combustion emissions, upstream methane leaks; we assume a 0.17% leakage rate for the distribution system. We again rely on EPA estimates of the social cost of GHGs ($190/ton CO2e) net of the allowance price to estimate unpriced climate costs. In principle, because our estimated social marginal cost exceeds the retail natural gas price, increasing the California carbon price would move natural gas prices closer to the true social cost of natural gas production and consumption.

Revenues from the sale of GHG allowances are rebated to households on an equal-per-customer account basis. Unlike electricity, this "lump-sum" approach is preferable because it preserves the high volumetric retail price signal while offering rebates to offset impacts on household finances. To better address affordability concerns, these consumer rebates could be targeted toward low-income households that spend a larger share of income on natural gas.

Carbon pricing impacts on retail gasoline prices

We follow a similar approach to decomposing retail gasoline prices in 2023, and contrasting these prices against an estimate of the social marginal costs associated with producing and consuming a gallon of gasoline in California.

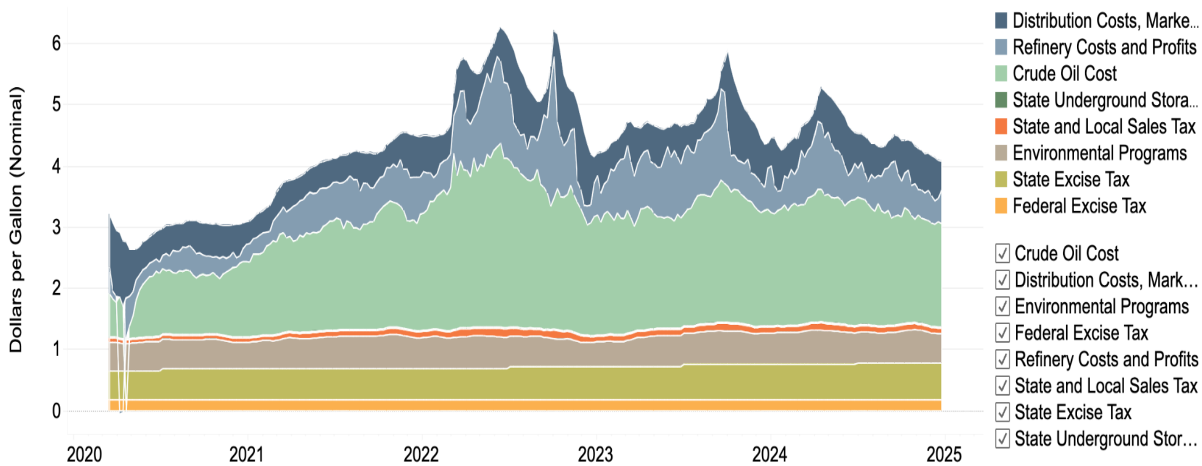
Variable gasoline supply costs: We assume full pass through of rack prices, credit card fees, and other variable costs incurred per gallon of gasoline sold in California.

GHG cap and trade compliance costs: Carbon market compliance costs reflect the costs that suppliers incur to hold GHG allowances to offset tailpipe emissions. We do not include any costs of holding GHG allowances to offset refinery GHG emissions; these should be close to zero on net due to output-based free allowance allocation. Gasoline suppliers must also comply with the low carbon fuel standard (LCFS), a companion policy which increases supplier costs in California. Estimates below reflect the costs of complying with the LCFS in 2023. Recent amendments to the LCFS will require a deeper reduction in the carbon intensity of transportation fuels by 2030.

We estimate that the California carbon price increased retail gasoline prices by approximately 26 cents (or 5%), in contrast with the $1.97/gallon in social cost associated with GHG emissions (including estimates of upstream emissions and valued at EPA social cost of carbon numbers).

To put these retail price impacts into perspective, the graphic below illustrates the impacts of environmental programs (namely the LCFS and the GHG cap-and-trade program) in addition to other cost components. The money that Californians spend on the "crude oil" component of gasoline prices is sent to global oil producers. Distribution and refinery costs and profits flow to California's refineries and fuel distributors. LCFS costs go to alternative fuel producers, many of whom are located outside California. But cap-and-trade costs are collected as carbon market revenues and can be put to work in service of our affordability objectives, while at the same time incentivizing Californians to find more socially cost-effective ways to meet their energy needs.

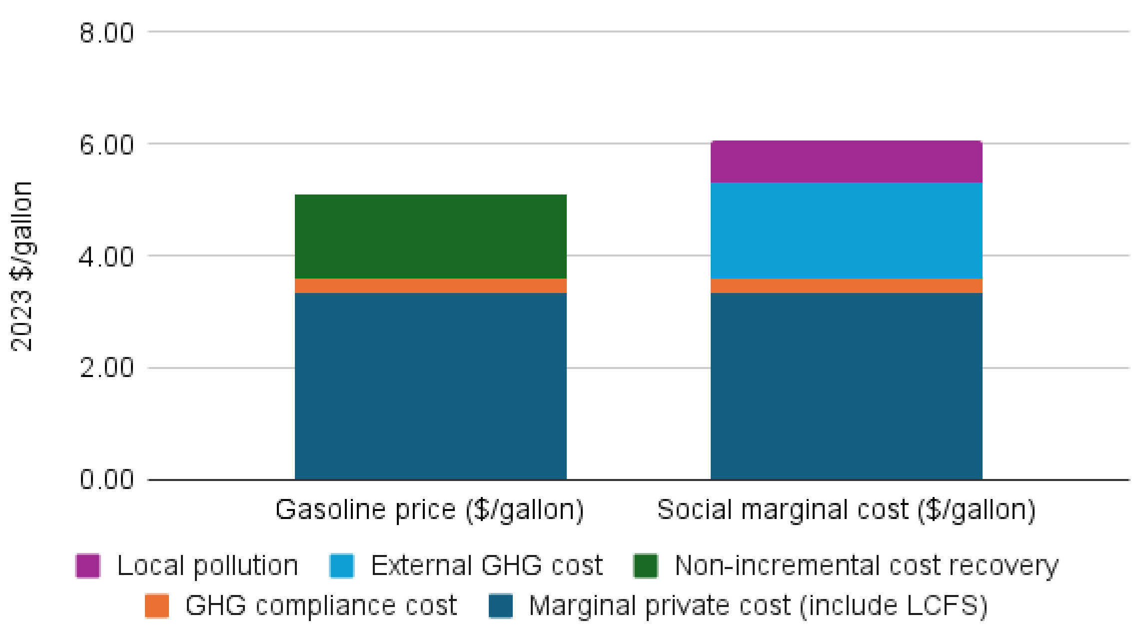
Figure 5: Estimated California Retail Gasoline Price Decomposition



Source: https://www.energy.ca.gov/estimated-gasoline-price-breakdown-and-margins

To further contextualize California's retail gasoline prices, the bar on the right in the graphic above summarizes our estimate of the social marginal cost of a gallon of gasoline. These calculations are based on the EPA social cost of GHG emissions (including upstream emissions) and local air pollution damage estimates per gallon.

Figure 6: 2023 Gasoline price versus social marginal cost (2023 $/gallon)

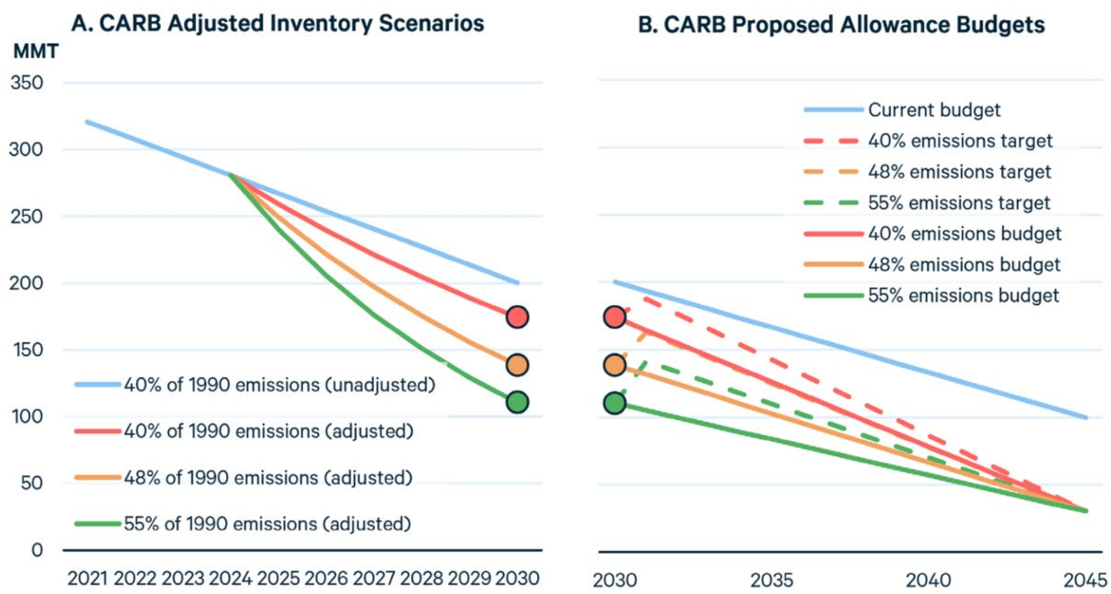


In contrast to natural gas (and electricity), carbon market compliance costs associated with retail gasoline are not rebated to consumers. There is no mechanism in place to rebate GHG allowance costs to households. However, GGRF revenues can be used to reduce the costs of less carbon intensive transportation alternatives (such as EVs and public transportation).

Forecasting future GHG allowance prices

The current cap-and-trade program budgets include more GHG allowances through 2030 than regulated entities are expected to need. The blue line in the figure below tracks the current allowance allocation schedule which does not put California on track to meet its 2030 or 2045 GHG reduction goals. This has prompted some important discussions around reducing the supply of GHG allowances in the market.

Figure 7: Proposed Allowance Supply Budgets (CARB)



Source: CARB Cap and Trade Workshop October 5, 2023

The Air Resources Board has convened a series of workshops to develop a potential update to the program regulation to reduce the cumulative supply of allowances and align it with the state's emissions reduction goals considering a variety of strategies illustrated in the figure. The percentage levels describe the budget for 2030 and the alternative pathways describe allowance budgets after 2030. Subsequently in the workshop series, CARB has analyzed several alternative ways to attain the 48% emissions target allowance supply budget. A 48% reduction would align the program with the needed ambition identified in the 2022 Scoping Plan Update to be on track to achieve statutory 2045 targets. The emissions caps in 2030 are below the associated percentage reduction target to accommodate an inventory adjustment that is implemented concurrently. Looking forward, in 2025 the California Legislature is expected to pursue a reauthorization of the cap-and-trade program.

To inform these important conversations and deliberations, economists and analysts have been exploring the likely implications of market reforms for market clearing GHG prices.

- Bushnell et al. (2023) use a statistical model to project a range of business-as-usual California emissions and emissions abatement under uncertainty about economic activity and abatement.
- In April 2024, CARB released a Standardized Regulatory Impact Assessment (SRIA) for the anticipated 2024 amendments to the carbon market, singling out the 48 percent target scenario (2030 GHG emissions reach 48% of 1990 levels).
- In May 2024, RFF released a report (Roy et al. 2004) summarizing Haiku modeling of GHG prices and distributional impacts under CARB's various considered approaches to achieving the 48 percent target scenarios.

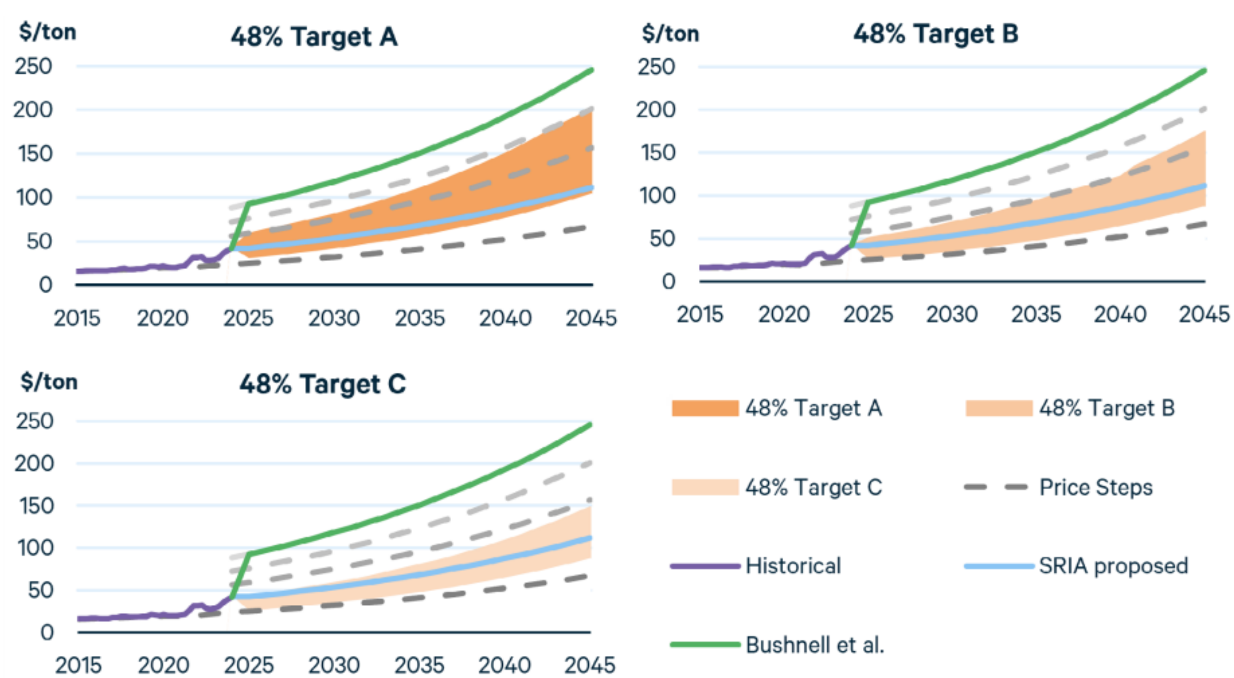
These model projections are illustrated in Figure 8 for the three approaches to achieve the 48% target considered by CARB during its recent workshop series. Scenario A would remove allowances from cumulative supply by reducing the annual budget of new allowances. Scenario B would remove half from the annual budget and half from the Allowance Price Containment Reserves, which otherwise would make these allowances available if the allowance price reaches specified levels. Scenario C removes all available allowances from the price containment reserves and only the necessary residual from the annual budget. The figure includes price steps as dashed lines illustrating the price floor, the two Allowance Price Containment Reserves, and the price ceiling, where potentially an unlimited number of (non-transferable) additional compliance instruments could be available.

It is important to note that future energy costs, energy use, and energy-related emissions trajectories are highly uncertain due to uncertainty about future technology costs, regulatory outcomes, global economic conditions, etc. Different modeling approaches and underlying assumptions lead to different price projections. The Bushnell et al. results embody uncertainty as probability distributions over these factors. The central (median) draw from a probability distribution of projected allowance prices is illustrated in the figure by the solid green line which quickly reaches the allowance price ceiling in Scenario A. The same outcome is illustrated for Scenario B although it is not explicit in the Bushnell et al. results. They also modeled a scenario similar to Scenario C that had prices just below the price ceiling. The Bushnell et al. results do not account for the impacts of the Inflation Reduction Act, nor many of the assumptions built into the 2022 Scoping Plan regarding the deployment of nascent technology, which might lower allowance prices in the future.

The SRIA projections shown as the blue solid lines reflect future allowance demand as described in the 2022 Scoping Plan, with minor adjustments. As illustrated in the figure, the SRIA assumes that the average allowance prices will fall halfway between the price floor and the first Allowance Price Containment Reserve. The SRIA did not distinguish among the different approaches to reducing allowance supply in Scenarios A, B, and C. It should be noted the SRIA is a conceptual analysis, not reflective of a specific policy proposal by CARB.

RFF's analysis presents two levels of initial allowance demand—one if all emissions reductions in the Scoping Plan occur leading to a lower price path, and another assuming that emissions reductions in the buildings and industrial sector are delayed and light-duty vehicles reduce vehicle miles travelled less than expected leading to a higher price path. These two levels of allowance demand bookend a range of price paths illustrated by the brown bands of prices. The Haiku results include investments from the Inflation Reduction Act.

Figure 8: Allowance Price Ranges Across SRIA Scenarios (2023$)



Source: Roy et al.2024.

As noted above, given the multiple sources of significant uncertainty in these modeling exercises, allowance price projections vary across studies and scenarios. Directionally, and intuitively, all studies project increases in allowance prices if allowance supply is reduced and/or the program is re-authorized.

How would projected carbon prices impact energy prices?

A detailed analysis of how projected GHG allowance prices would impact consumer energy prices in California is well beyond the scope of this report. We can, however, multiply allowance price projections by fuel-specific GHG intensities to coarsely assess how higher permit prices would impact supplier costs (and thus consumer prices under full pass-through assumptions), holding all other factors equal.

The impact of higher allowance prices on electricity rates is not only a function of the allowance price, but will also be determined by the share of fossil fuel generation in the electric generation mix. As the carbon intensity of grid electricity decreases, the impact of rising allowance prices on electricity bills will be mitigated. We therefore report two sets of electricity rate calculations: one assuming the current GHG intensity of marginal electricity generation and one that assumes a 50 percent reduction in GHG intensity.

Table 1: Calibrated Retail Energy Price Impacts of California Carbon Pricing (2023$)

	2023 Marginal Private Cost of Energy	2023 Marginal Social Cost	2023 Retail Prices	Cost Impact at 2023 GHG Price ($33/ton)	Cost Impact at SRIA GHG Price Projection ($53.72/ton)	Cost Impact at 2030 GHG Ceiling Price ($118.26/ton)
Electricity ($/kWh) Current grid	$0.07	$0.14	$0.34	$0.02	$0.02	$0.05
Electricity ($/kWh) 2040 grid (assume 50% reduction in GHG intensity)	$0.07	$0.11	$0.33	$0.01	$0.01	$0.02
Natural gas ($/therm)	$0.80	$2.57	$2.10	$0.18	$0.29	$0.63
Gasoline ($/gallon)	$3.60	$6.08	$5.08	$0.26	$0.42	$0.93

Table 1 shows the impact of higher allowance prices compared to the 2023 average carbon price ($33/ton CO2e) on fuel supplier costs and retail energy prices. These are very simple calculations that ignore any supplier and consumer responses to higher energy prices. Our aim with these "all else equal" calculations is to put the compliance cost impacts of higher GHG allowance prices into some context. Impacts on electricity costs are small, especially when we account for the declining GHG intensity of California's electricity supply system. Impacts of higher carbon prices on natural gas and gasoline supply costs are more substantial.

This table focuses on retail energy prices. But the impacts of higher retail energy prices on future household expenditures will depend on the extent to which Californians continue to rely on gasoline and natural gas for their transportation and building energy needs. If electricity use constitutes a growing share of household energy consumption relative to other fuels, while the carbon intensity of electricity generation falls, the impacts of rising allowance prices on household energy bills will be mitigated. For this future to be realized, however, GHG allowance prices and retail electricity prices need to be structured in a way that more accurately reflects the true cost of electricity, natural gas, and gasoline consumption.

Conclusion

California carbon prices are projected to increase if the cap-and-trade program is re-authorized. The extent of this price increase is uncertain. Projected allowance price paths vary depending on what is assumed about the pace of technological change, the stringency of the GHG cap, the availability of low cost GHG abatement opportunities, macroeconomic factors, the performance of overlapping prescriptive climate policies, among other factors. GHG allowance prices in California have been lower than many observers anticipated fifteen years ago when the program was being designed. Going forward, California has numerous regulatory tools to influence the price path inside and outside the carbon market, including the development of companion regulations to accelerate technical change in specific sectors.

Even at moderate price levels, California's GHG cap-and-trade program will impact retail energy prices. Targeted climate credits can ease the burden on household budgets in the short run. In the longer run, elements of program design such as strategic investments from the GGRF can accelerate the electrification of transportation and buildings. This transition, together with efforts to decarbonize California's electricity grid, will mitigate the impacts of higher GHG prices on household energy costs.

We offer the following observations and recommendations to CARB and the legislature.

1. **Over time, a reduced reliance on fossil fuels will benefit household finances and public health.** The GHG cap-and-trade program has a critical role to play in

providing incentives to reduce fossil fuel consumption, delivering cost-effective GHG reductions across the economy.

2. **Carbon prices have played a small role in driving retail electricity price increases because the California electricity grid is not very carbon intensive (and getting cleaner by the year).** We estimate that carbon prices increased retail electricity prices by less than 5% in 2023 (using PG&E data). Climate change adaptation costs, such as wildfire risk mitigation, are causing more significant increases. Importantly, the utility bill impacts of carbon pricing have been largely offset by the climate credit.

3. **Restructuring the climate credit to reduce volumetric electricity rates would make electrification a more affordable choice for investments by households and businesses.** This design would improve the efficiency of regulatory pricing in general by bringing electricity prices closer to their full social marginal cost. The state should also consider making this credit more salient to households, and targeting the credit towards lower income groups to improve economic outcomes for the most vulnerable households. See, for example, Smith et al. 2024.

4. **Carbon pricing has increased natural gas prices by an estimated 8%.** This increase notwithstanding, retail natural gas prices in California are still below estimates of social marginal cost. Thus, climate credits that transfer revenues to households in lump sum serve to mitigate financial impacts while preserving the incentive to move away from relatively carbon intensive natural gas.

5. **The climate credit for natural gas customers could be made more salient and more targeted towards low-income households.**

6. **A higher carbon price would increase retail gasoline prices in California, more accurately signaling the assessed social cost of gasoline consumption.** Transportation represents the largest source of GHG emissions in the state. Transmitting the climate costs of gasoline consumption will support more sustainable transportation choices, and retail gasoline prices in California are below the estimated marginal social cost of gasoline consumption.

7. **Auction revenues could be used to help households transition away from gasoline consumption.** A growing share of GHG allowance revenues come from the transportation sector; some of these revenues could be used to ease the burden of transportation-related costs, while at the same time accelerating the transition away from fossil fuels.

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Chapter 2. Cap-and-Trade and Cost Containment in California

Meredith Fowlie and Brian Holt

California has established a goal of reducing statewide greenhouse gas (GHG) emissions to 40% below 1990 levels by 2030. Policy design choices will play a decisive role in determining what it costs to meet this goal and how these costs will be allocated. To ensure that California's clean energy transition is affordable and equitable, cost-containment and fair cost allocation should be guiding principles.

This chapter underscores the importance of this cost-containment imperative. We begin by discussing the role that a GHG cap-and-trade program can play in keeping the costs of achieving GHG emission targets in check. We show how, **if companion policies are used to incentivize or mandate specific forms of GHG abatement, this can increase overall abatement costs while reducing GHG allowance prices if mandated abatement strategies are relatively costly.**

The second part of the chapter surveys available evidence on current and proposed companion climate policies in California. This evidence indicates that **some of California's prescriptive policies, including some clean technology subsidies, deliver GHG reductions at a relatively high cost per ton of GHG abated.** We note that these cost-per-GHG-ton-abated metrics are not comprehensive measures of a program's performance; comparisons across programs should be interpreted carefully. This important caveat notwithstanding, given rising GHG abatement costs and mounting concerns around affordability (see Chapter 1), we argue that it will be important to ensure that prescriptive regulations are implemented in a way that aligns with cost containment objectives along with other policy goals.

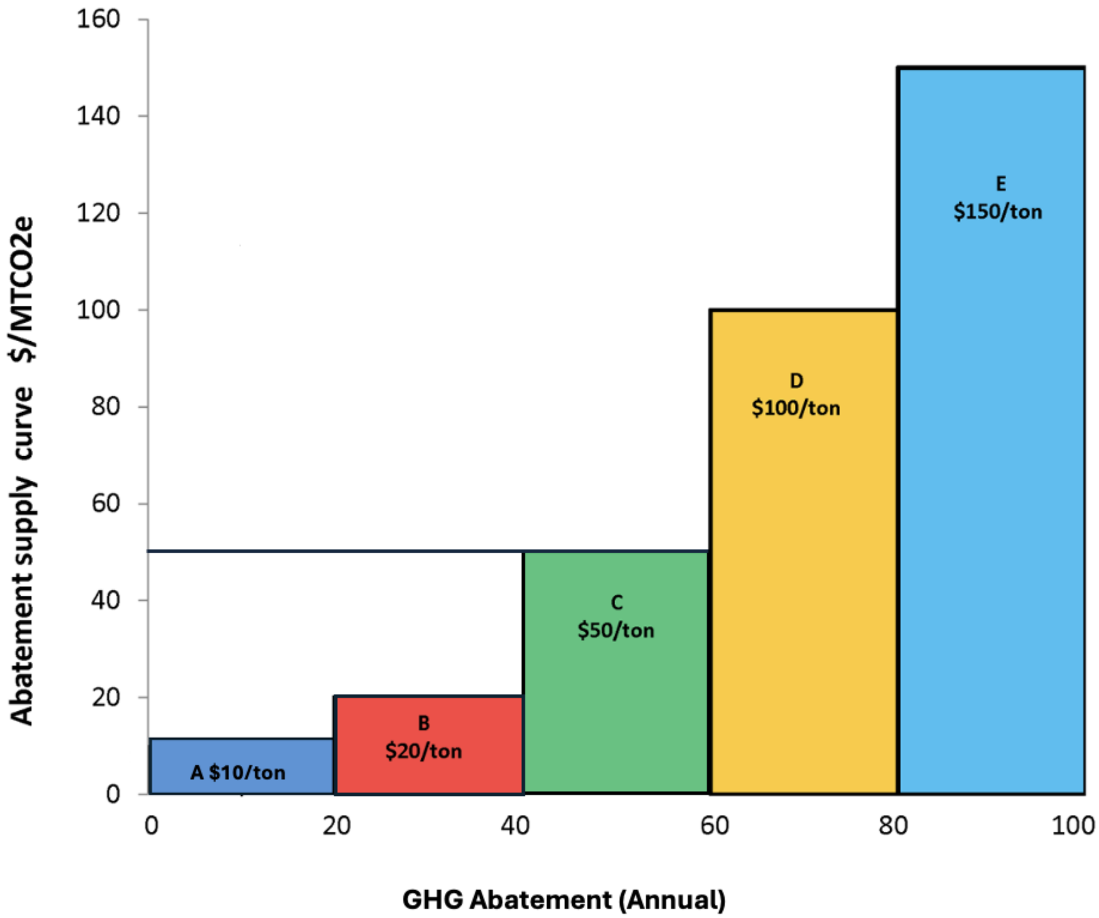
Cost-containment advantages of cap-and-trade

As California pursues deeper GHG reductions, the costs of achieving additional reductions are increasing. High costs of living in California, and mounting concerns around affordability, make it important to seek out the most promising and least costly GHG abatement options.

California's GHG cap-and-trade program has been designed to incentivize and coordinate cost-effective GHG reduction abatement. The stylized graphics below illustrate the basic intuition behind how this market-based coordination is designed to work (Figure 1) and how interactions with more prescriptive "companion" policies can impact carbon market outcomes (Figure 2).[2] The staircase graphic in each figure is meant to represent a stylized set of GHG abatement options (e.g. increased adoption of electric vehicles, accelerated deployment of renewable energy generation, industrial decarbonization)

[2] This graphical illustration is based on a 2016 blog post, "Time to Unleash the Carbon Market?", from June, 2016.

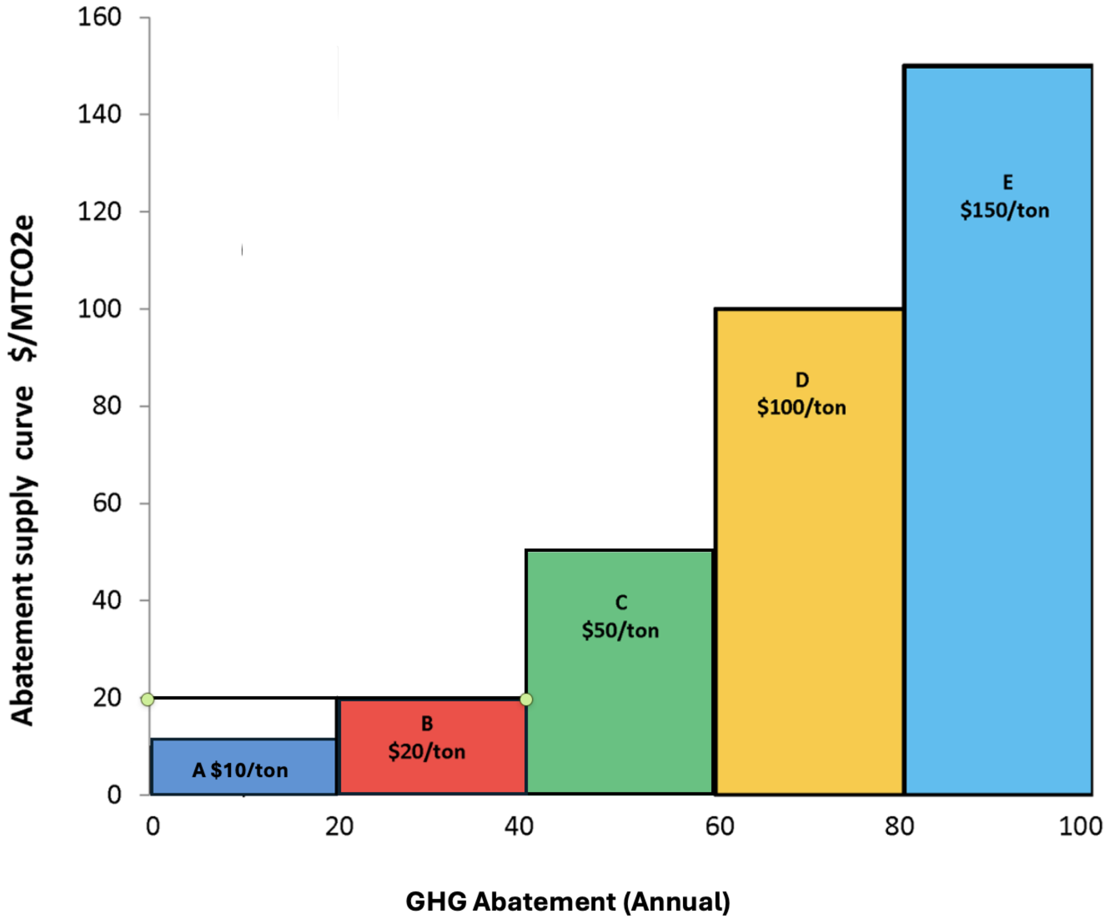
arranged in ascending order of abatement cost. The height of the blocks measures the cost per ton of CO2 emissions reduced. The width of the blocks measures achievable GHG emissions reductions.



Suppose that California policy makers have set a GHG emissions target that requires a reduction of 60 units below "business as usual" emissions. If a GHG cap-and-trade program was used to coordinate this abatement, the market price would increase until this level of GHG abatement has been supplied by market participants. In this very simple example, a price of \$50 delivers the desired GHG reductions. The total abatement cost incurred to meet the target:

A + B + C = (20 x \$10) + (20 x \$20) + (20 x \$50) = \$1200.

Thus far, we have assumed that the carbon market is the only policy instrument driving GHG emissions reductions into the economy. However, California has historically relied on a combination of carbon pricing and prescriptive policies (e.g. clean technology mandates and subsidies) to encourage GHG abatement. With this in mind, now suppose policy makers mandate the deployment of options A and E to deliver 40 units of the desired abatement. Under this scenario, the role of the carbon market is reduced to delivering only the 20 units of abatement (i.e. strategy "B") required to meet the target.



Under this policy regime which combines prescriptive policies with the carbon market mechanism, the total cost of meeting the emissions target would be:

A + B + E = (20 x $10) + (20 x $20) + (20 x $150) = $3600.

The market clearing price required to deliver 20 units of abatement is $20/ton abated. Note that this combination of prescriptive policies with the carbon market increases the overall cost of achieving the GHG reduction target.

This exposition is overly simplistic of course. It ignores tremendous amounts of uncertainty around business-as-usual emissions trajectories, technology costs, etc. But these pictures help to elucidate how interactions between carbon markets and more prescriptive climate policies impact carbon market prices and abatement costs. More specifically, **if companion policies are used to incentivize or mandate specific forms of GHG abatement, this can increase overall abatement costs while reducing GHG allowance prices if mandated abatement strategies are relatively costly.**

This simple example begs the question: *Why would policy makers mandate relatively expensive GHG abatement alternatives?* There are several possible reasons.

First, it can be very challenging for policymakers to anticipate which abatement options will hold the greatest potential in the future. Whereas the graphs above provide a clear snapshot of GHG abatement costs at one point in time, the reality is far less clear - and far more dynamic. Policy makers are working with limited and uncertain information about which abatement options will deliver GHG reductions most cost-effectively going forward. Carbon market mechanisms are designed to respond to evolving technological innovations and market conditions. In other words, a well-functioning carbon market mechanism will coordinate the least cost abatement without knowing in advance what the most promising strategies will be.

Second, policymakers might want to encourage more expensive GHG abatement alternatives that offer significant “co-benefits”. The cost per ton metric used in the figures above can be useful for drawing cost comparisons across abatement strategies, but this metric fails to capture other benefits, such as local air quality or biodiversity or technological change. These co-benefits can justify the deployment of strategies that deliver GHG reductions at higher cost per ton.

Third, mandates and regulations provide more ex-ante certainty around what types of investments a climate policy will support. More prescriptive policy commitments can be useful in the presence of network effects, and/or in sectors where decarbonization requires capital-intensive, long-lived infrastructure investments. However, this certainty can come at a cost if mandated technologies prove to be less cost-effective ex post.

Finally, policymakers may elect to pursue relatively costly prescriptive policies because the benefits generated by these policies tend to be more salient, whereas the costs are less visible (as compared to carbon pricing). Carbon pricing can be politically unpopular because the costs are highly visible, whereas the GHG abatement benefits are hard to directly observe.

How do costs of companion programs compare to allowance prices?

The graphics above illustrate how a reliance on more prescriptive approaches can increase the overall cost of meeting our GHG abatement targets if some (or all) of the prescribed GHG abatement options are relatively costly. California has relied heavily on more prescriptive policies (e.g. renewable energy mandates) and technology-specific subsidies (e.g. rooftop solar subsidies). How do the costs of these policies compare to the market price of GHG allowances?

The costs of more prescriptive policies are relatively challenging to estimate. A detailed empirical analysis of California's climate policies and programs is well beyond the scope of this report. Instead, we summarize results from other studies that have endeavored to construct cost-per-ton measures for specific policies and programs. Appendix A summarizes some of the available evidence for policy instruments that are currently being used to deliver GHG emissions reductions in California. An important caveat when comparing these estimates: input assumptions and cost accounting approaches vary significantly across studies. These comparisons should be viewed as illustrative versus definitive.

Table 3-11: Estimated cost per metric ton of reduced CO_2e relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Annual Cost, 2035 ($/ton)	Average Annual Cost, 2022–2035 ($/ton)	Annual Cost, 2045 ($/ton)	Average Annual Cost, 2022–2045 ($/ton)
Deploy ZEVs and reduce driving demand	-171	-99	-103	-122
Coordinate supply of liquid fossil fuels with declining CA fuel demand	60	109	-50	39
Generate clean electricity[a]	101	156	145	161
Decarbonize industrial energy supply	290	217	257	274
Decarbonize buildings	235	230	112	213
Reduce non-combustion emissions	93	94	106	99
Compensate for remaining emissions	745	823	236	485

[a] Note: The denominator of this calculation (2045) does not include GHG reductions occurring outside of California resulting from SB 100. If these reductions were included, this number would be lower.

Estimates of the ex post realized cost per ton of GHGs avoided varies widely across companion climate policies. In some cases, GHG abatement achieved using prescriptive policies is estimated to be significantly more costly (in terms of dollars spent per ton of CO2 avoided) as compared to the California carbon price (which was around $32/ton in 2023). In contrast, the costs of GHG reductions induced by the California Renewable Portfolio Standard (RPS) look quite low now that solar and wind technology costs have fallen (below $10/ton).

Looking ahead, the 2022 Scoping Plan includes some ex-ante cost estimates for measures considered in Scoping Plan scenarios. Here again, we see significant variation in abatement cost estimates across programs and policies, with many cost estimates significantly exceeding current and forecast GHG allowance prices.

Conclusion

California's pursuit of greenhouse gas (GHG) emission reductions will require a careful balancing of cost containment and climate ambition. The state's cap-and-trade program offers a powerful tool to minimize the costs of emission reductions by coordinating the most cost-effective abatement options. However, this cost-effectiveness is often overshadowed by the more visible costs of carbon pricing, which can be politically unpopular.

Prescriptive policies deliver more salient GHG reduction benefits. But the hidden costs of these policies can be substantial. A reliance on relatively costly mandates, standards, and subsidies could significantly increase the overall cost of GHG abatement while also putting downward pressure on the GHG allowance price (and thus reducing the incentives to reduce GHG emissions in other parts of the California economy).

We offer the following observations and recommendations to CARB and the legislature.

1. As the state moves forward with its climate change mitigation efforts, maintaining a focus on cost containment will be essential to ensuring that its clean energy transition remains both affordable and effective. In this respect, re-authorization of the cap-and-trade program has a critical role to play.
2. More prescriptive companion policies can provide important benefits. However, given the imperative to contain and manage the cost impacts of climate action in California, these benefits should be judiciously weighed against the potential costs.
3. In addition to the cost-effectiveness advantages of carbon pricing, the GHG cap-and-trade program generates state revenues. These revenues can be used to address affordability concerns among other objectives. We discuss this topic in more detail in Chapter 1.

Appendix A

The costs of more prescriptive policies are challenging to estimate. A detailed empirical analysis of California's climate policies and programs is well beyond the scope of this report. To provide a high-level comparison across programs, we summarize results from other studies that have endeavored to construct cost-per-ton measures for specific policies and programs. An important caveat when comparing these estimates: input assumptions and cost accounting approaches vary significantly across studies. These comparisons should be viewed as illustrative versus definitive.

i. Rooftop solar subsidies

In past years, California has compensated customers who install rooftop solar on their homes (or businesses) at retail rates for excess energy they generate and feed back into the electric grid. These "net energy metering" (NEM) customers also save money when they consume the electricity their panels produce (versus paying the retail rate for grid electricity). This program has been effective at accelerating the adoption of rooftop solar panels.

To (coarsely) assess the implicit costs incurred when we reduce GHG emissions via investments in rooftop solar PV, we need to estimate both the social value of the electricity generated by PV systems (including the avoided air pollution and climate damages), and we need to estimate the increase in supply costs. A detailed analysis of these benefits and costs is beyond the scope of this report. We provide rough estimates drawn from public data and basic calculations.

Abatement Costs: According to the 2024 Tracking the Sun report, the median installed solar PV system price in 2023 in California was $4.2/W DC for residential solar PV. Using a time horizon of 20 years and a discount rate of 2%, we calculate an annualized cost is $0.26/W DC. If we further assume that a 1 W DC solar panel would generate approximately 1.5 kWh per year, this implies a levelized cost of over $0.17 per kWh.

Of course, the system installation costs incurred by a homeowner can exceed the technology and infrastructure costs. Some of these homeowner costs may be offset by tax credits and subsidies. Transfers from homeowners to rooftop solar PV installers, or transfers from tax payers to rooftop solar adopters, have implications for the allocation of costs. Here, we are focused on estimating the social costs (e.g. technology costs) so that we can assess the empirical analog of the abatement costs incurred to reduce GHGs via rooftop solar adoption and generation.

To estimate the GHG emissions avoided when a rooftop solar PV system generates a kWh of electricity, we use the average marginal emissions intensity in 2023 which is approximately 0.4 tons CO2/MWh (this over-all-hours average likely over-estimates the rate of GHG emissions displacement in daylight hours when solar panels are generating electricity). The marginal cost of grid electricity production in California was around 6 cents/kWh in 2023. Dividing the additional cost per kWh generated using rooftop solar PV (i.e. $0.17/kWh-$0.06/kWh) by the tons of CO2 displaced by solar electricity production, we estimate that it cost over **$270/ton** to reduce a ton of CO2 via investments in rooftop solar.

There are reasons to think that this *under*-estimates abatement costs per ton of GHG avoided. The emissions intensity of the California grid is expected to decrease over the life of these PV systems (and the quantity of GHG emissions displaced falls). Moreover, because some of the investments in rooftop solar would have happened even absent the subsidy, $270 is a lower bound on the costs of GHG abatement due to the NEM subsidy.

On the flip side, this approach could *over*-estimate GHG abatement costs insofar as we under-estimate avoided costs. Some benefits not captured in this very simple analysis include the benefits of learning that can reduce technology costs and improve system performance going forward, and some costs of integrating utility-scale renewables that are not fully captured by the TTS cost estimates.

ii. Renewable Portfolio Standard (RPS)

California's RPS mandates that 60% of grid electricity sales should be sourced from renewables by 2030. To the extent that qualifying renewable resources are more expensive to procure than the generation resources that would otherwise be used, this policy will increase the cost of electricity generation in California. Calculations below are based on the analysis summarized in Borenstein et al. 2022.

Cost/ton CO2e avoided: The CPUC tracks RPS and non-RPS procurement expenditures in terms of $/kWh and annual RPS revenue requirements. RPS procurement costs have fallen at a rate of 13 percent per year between 2007 and 2019. In 2019, the average RPS energy contract price across all technology types was $28/MWh. As renewable energy technology costs have fallen, so has the above-market premium for renewable energy generation. The average difference in RPS versus non-RPS procurement costs reported by the large investor-owned utilities had dropped to $0.0028/kWh in 2019 (CPUC, 2020). This translates to a very low cost per ton of GHG abatement (below **$10/ton CO2e**). We note that this is lower than cost estimates constructed by the California Legislative Analyst's Office. One reason is that we are using current procurement costs which are significantly lower than technology costs incurred in the early years of RPS compliance.

Energy affordability and incidence: Borenstein et al (2021) estimate the retail rate impacts of RPS compliance. On a per kWh basis, these residential rate impacts of RPS compliance are very small. The authors estimate average residential rate impacts per kWh of $0.00, 0.006 and $0.0001 for SDG&E, PG&E and SCE, respectively.

iii. Low carbon fuel standard (LCFS)

The Low Carbon Fuel Standard is designed to decrease the carbon intensity of California's transportation fuel utilization and incentivize the use of low-carbon and renewable alternatives to support climate change mitigation and deliver air quality benefits.

Cost/ton CO2e avoided: California LCFS prices currently exceed **$75/ton CO2e**. The LCFS price has consistently exceeded the GHG allowance price, implying that we have been paying a lot more for GHG reductions under the LCFS program versus the carbon market. These LCFS prices likely under-estimate the costs per ton of CO2e abated due to concerns around additionality of RNG, EV crediting, and the lifecycle-based calculations of GHG content.

Energy affordability and incidence: Complying with the LCFS increases gasoline supply costs and consumer gas prices. In contrast to the cap-and-trade program, which raises revenues that can be rebated to households and firms, the LCFS does not generate revenues for California.

iv. EV subsidies

The Inflation Reduction Act offers California households a $7,500 federal tax credit to incentivize EV adoption. Although this is not currently a California program, Governor Newsom has indicated that California will step in to provide a California ZEV rebate if the incoming Trump Administration follows through on its threat to eliminate the federal tax credit.

A recent paper by Allcott et al. (2024) analyzes the costs and benefits associated with IRA EV tax credits (relative to a baseline with no incentives offered). These authors estimate that IRA EV tax credits have increased annual registrations of US firms' EVs by 37 percent, or 310,000 annually. Compared to pre-IRA policy, IRA EV credits generated an estimated $1.87 of US benefits per dollar spent in 2023, at taxpayer cost of $32,000 per additional EV sold. This per-vehicle cost exceeds the subsidy level because only 23 to 33 percent of credits are additional.

A "global" cost of **$135/ton of GHG** emissions avoided by these EV subsidies. Because the design of the IRA EV subsidies favors domestic vehicle manufacturers, the estimated *domestic* cost per ton is much lower (**$10/ton**). EV tax credits do not directly impact energy prices because they are funded by federal taxpayers. Accelerated adoption of EVs should reduce volumetric electricity prices in California insofar as increasing demand for electricity spreads fixed cost recovery over a broader base.

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Chapter 3. Allowance allocations and financial flows

Danny Cullenward and Katelyn Roedner Sutter

This chapter describes how the total number of allowances authorized each year are distributed to market participants via free allocation and auctioning mechanisms. It also illustrates the approximate financial value of allowance allocations, allowance auctions, and carbon offset credit issuance (Figure 1), based on existing public data from CARB.[3]

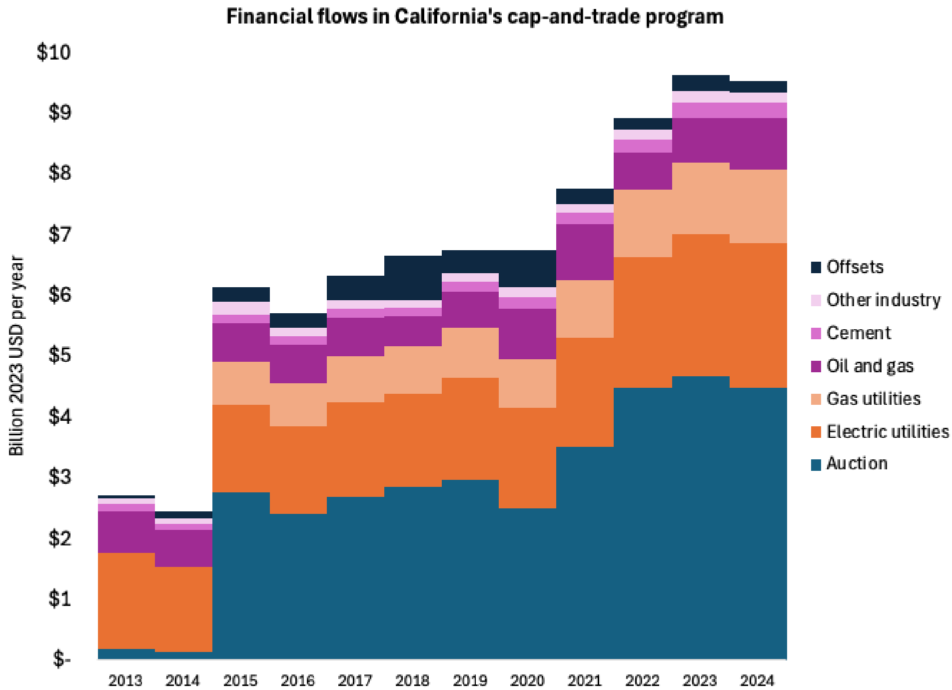
CARB's program regulations establish an allowance budget for every program year and designate the number of allowances that are freely given to industrial emitters for leakage prevention, freely given to utilities for the purpose of benefiting ratepayers, and sold at quarterly auctions to raise revenue for the Greenhouse Gas Reduction Fund (GGRF). In addition to the annual allowance budget, CARB's regulations also authorize the compliance use of carbon offset credits. As discussed in Chapter 7, because these credits are available in addition to the allowance budget, they expand the supply of compliance instruments available in the market.

As Figure 1 illustrates, the annual value of allowances entering the market and offset issuance over the last few years has been close to $10 billion per year. The total is about double the value of the money raised from allowance auctions for the Greenhouse Gas Reduction Fund (GGRF) because slightly less than half of the allowances are auctioned, as explained below.

One important caveat should be noted about Figure 1. The financial flows are based on the regulatory schedule for how allowances enter the market during periods of normal demand. When demand is low, allowances may not be purchased at auction. The market regulations provide that when demand increases, previously unsold allowances can be reintroduced and sold at auction. This occurred when demand fell in 2016 and 2017 but recovered following the passage of Assembly Bill 398 in 2017. Most of the unsold allowances were reintroduced and sold in 2017, 2018, and 2019. Figure 1 does not show these dynamics, and for simplicity assumes that allowances are sold on schedule each year. That assumption is reasonable and reliable for recent years but is not for the period 2016-2019.

3 CARB, Cap-and-Trade Program Data Dashboard; CARB, Cap-and-Trade Program Data.

Figure 1: Summary of financial flows[4]



Allowance budgets

The cap-and-trade program regulations establish annual allowance budgets and allocate those supplies across four categories (see Figure 2):

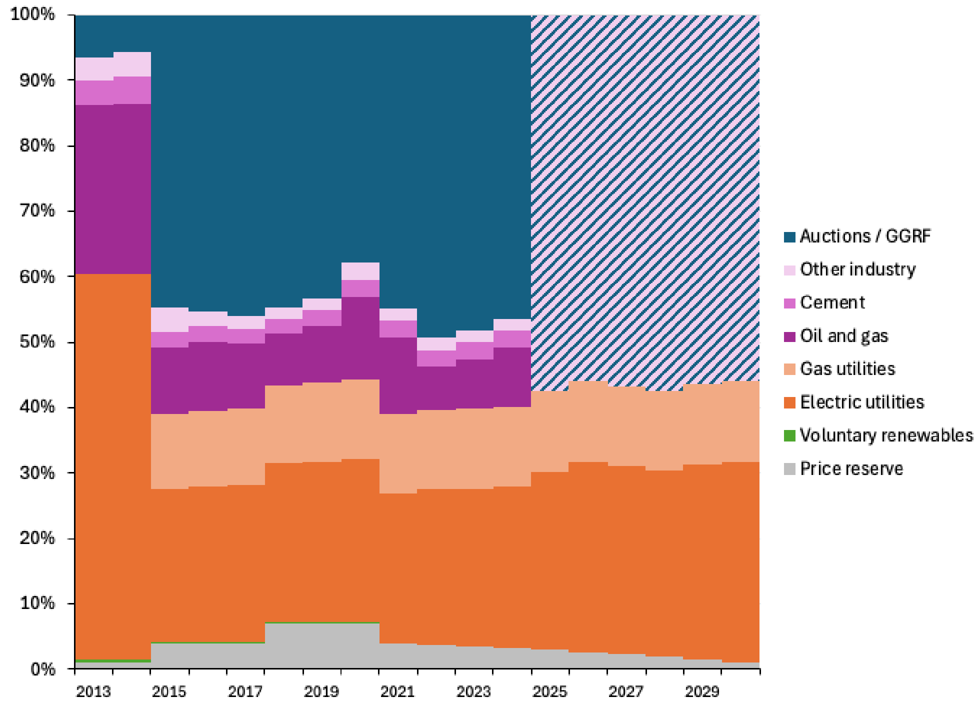
- **Auction sales that generate revenue.** About 42–49% of allowances are held by the state and offered for sale at quarterly auctions. Sales of these allowances raise revenue for the Greenhouse Gas Reduction Fund (GGRF), which has collected $4–5 billion per year over the last several years. Revenues depend both on the number of allowances sold and the auction settlement price.[5] A little more than two-thirds of the revenues that come into the Greenhouse Gas Reduction Fund are continuously appropriated, with less than a third subject to the annual legislative appropriations process.[6]

4 Key assumptions: (1) allowance supplies are based on calendar-year allocations, not the date of actual auction sales and (2) allowance and offset prices are annual averages. Because tens of millions of allowances were offered for sale but not purchased in 2016-17, with most purchased later 2017-19, actual revenues differ from what is shown. Note that the program only covered electricity and industrial emitters in 2013-14, and expanded significantly in 2015.

5 See Chapter 3 in the IEMAC's 2020 Annual Report.

6 Legislative Analyst's Office, The 2024-25 Budget: Cap-and-Trade Expenditure Plan.

Figure 2: Allowance budget shares

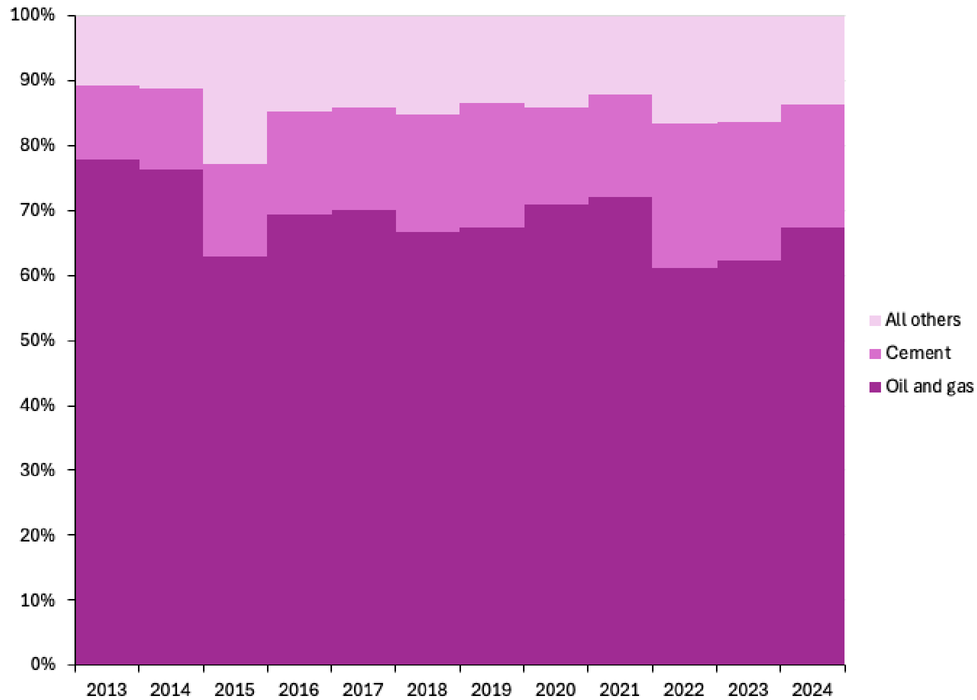


- **Free allocations to industry.** About 10–15% of allowances are freely given to regulated emitters to protect against competitiveness concerns, including the risk that carbon pricing merely "shifts" industrial activity outside of California and causes the associated greenhouse gas emissions to "leak" outside of the program's boundaries. These concerns are most pronounced for emissions-intensive, trade-exposed industries.[7] The idea behind free allowance allocations is to preserve the incentive to reduce pollution while providing a transfer of resources that reduces the cost of compliance: firms that receive free allocations need to purchase fewer allowances to comply with program regulations and can sell those allowances if they can cut pollution at a lower cost than the market price for allowances. Although more than 200 firms receive free allowance allocations across dozens of economically important industries, the allocations are highly concentrated. About 61–72% go to the oil and gas industry (principally oil refineries), another 14–22% go to cement

7 See Chapter 4 in the IEMAC's 2018 Annual Report; Chapter 2 in the IEMAC's 2020 Annual Report; and the final chapter in the IEMAC's 2021 Annual Report.

producers, and the remaining 12–17% go to all other industries combined (see Figure 3).[8]

- **Figure 3: Free allocations to industry by category**



- **Free allocations to utilities.** About 23–30% of allowances are freely given to electric utilities and 11–12% of allowances are freely given to gas utilities, in both cases for the purpose of benefiting utility ratepayers.[9] Investor-owned electric utilities (electric IOUs) are required to "consign" their allowances to quarterly auctions, purchase the number they need for compliance purposes at auction, and use any funds collected from the sale of their consignment allowances to benefit their customers, primarily through the on-bill California Climate Credit that IOU ratepayers receive twice a year. Publicly owned electric utilities (electric POUs) enjoy greater flexibility. Electric POUs are allowed to use the allowances they receive directly for compliance purposes and to sell them (including through consignment at auction), so long as funds are used to support clean energy and energy efficiency programs that benefit their customers. Private and public gas utilities are also required to use their allowances to benefit ratepayers, and must also consign a growing share of their allowances to auction. The impact of these ratepayer benefits is further described in Chapter 1 on affordability.

8 CARB, Annual Allowance Allocation Summaries.

9 See California Code of Regulations, Title 17, § 95892 (electric utilities); *id*. at § 95893 (gas utilities).

- **Reserve accounts.** Up to 7% of allowances were transferred to the program's Allowance Price Containment Reserve, where they can be purchased by market participants at specified prices that are higher than historical market prices. To date, no such sales have occurred, although extension and/or reform of the program could lead to market prices reaching levels at which market participants could seek to access these additional allowance supplies at designated reserve sales. A small number of allowances were also set aside in a Voluntary Renewable Energy Reserve and retired to avoid double-counting of climate benefits from the use of voluntary renewable energy credits.[10] All of these allowances have been retired, such that none remain in the Voluntary Renewable Energy Reserve.

The formulas for distributing the annual allowance budget to different applications vary in the current regulations. Some allowance distributions are fully specified in advance, including the number of allowances freely allocated to electric and gas utilities, the number transferred to the Allowance Price Containment Reserve, and the number transferred to the Voluntary Renewable Energy Reserve. In contrast, the formula used to calculate free allocation to industry for competitiveness considerations is based on observed industrial production levels times the (annual percentage) cap adjustment factor times a benchmark emissions intensity measure times an assistance factor that reflects emissions leakage risk. These factors are all specified by regulations or legislation except for the observed production levels; hence, the allocation to industry is not fully specified in advance (this distribution is also discussed in Chapter 5 on environmental justice).

Offset supplies

As discussed in Chapter 7 of this year's report, the supply of carbon offset credits expands the cap-and-trade allowance budgets. As a result, offsets expand the supply of compliance instruments that regulated emitters can use to comply with program rules. CARB reports average prices for offset transactions.[11] Almost 233 million compliance offset credits have been issued to date (net of buffer pool contributions), while about 209 million California-issued offsets have been surrendered for compliance purposes (along with another 1.4 million offsets issued by the Government of Québec).[12]

Undersubscribed auctions

Figure 1 reports the approximate value of allowance allocations and offsets issuance based on the allowance budget determinations made in the program rules. Actual

10 See California Code of Regulations, Title 17, §§ 95870(a), 95871(a), 95913 (allowance price containment reserve); *id*. at § 95481.1 (voluntary renewable energy reserve).

11 CARB, Summary of Market Transfers Report.

12 CARB, ARB Offset Credit Issuance Table (Dec. 24, 2024).

GGRF revenues differ when market participants elect not to purchase all of the allowances offered at auction. This occurred in 2016 and 2017, when concerns about the program's post-2020 legal authority had not yet been resolved. Most of the initially unsold allowances were reintroduced and sold by the end of 2019, while approximately 37 million were transferred to the program reserve accounts.[13] Due to the design of the auction mechanism, which sells utility-owned consignment allowances first and state-owned allowances only if demand warrants, revenue collected for the Greenhouse Gas Reduction Fund was particularly volatile from 2016-2019. The committee has previously observed that this mechanism prioritizes the stability of utility transfers (including the on-bill climate credit) at the expense of volatility in the Greenhouse Gas Reduction Fund.

Policy options

Policymakers can change the formulas for allocating allowances (covered in this chapter) as well as their approach to carbon offsets (covered in Chapter 7). The legislature has generally delegated authority to determine the allocation and auctioning of allowances to CARB. At times the legislature has also provided specific direction. For example, Assembly Bill 398 (Stat. 2017, Ch. 135) directed CARB to maintain the assistance factor that contributes to the calculation of free industry allocation levels that CARB had proposed to reduce;[14] AB 398 also set limits on the use of carbon offsets that were lower than what CARB had authorized in the past, though no statutory limits apply after 2030.[15]

In the context of re-authorization, potential policy interventions include:

- **Prioritizing GGRF revenue.** Increasing the share of allowances directed to auction would increase GGRF revenues, but would require corresponding reductions in other allowance allocations to industrial emitters, electric utilities, and/or gas utilities.

- **Prioritizing ratepayer rebates.** Increasing the share of allowances freely allocated to electric utilities would lead to larger ratepayer rebates for investor-owned utility customers, but would require corresponding reductions in other allowance allocations and/or auctions.

- **Reforming ratepayer benefits.** Policymakers could reform the way free allowances are used by electric and/or gas utilities. For example, the legislature could direct the California Public Utilities Commission to direct consumer rebates to low-income consumers (rather than today's practice of issuing rebates to all households), direct

[13] CARB, Cap-and-Trade Allowance Report (per Board Resolution 18-51).

[14] Health and Safety Code § 38562(c)(2)(G).

[15] Health and Safety Code § 38562(c)(2)(E).

consumer rebates to reduce volumetric electricity rates, or impose new conditions on the use of allowance proceeds by publicly owned electric utilities and/or gas utilities. This is further discussed in Chapter 1 on affordability.

- **Reforming the balance of utility allocations.** Policymakers could decide to allocate different shares of free allowances between electric and gas utilities to reflect the state's broader commitment to the electrification of building energy services while preserving overall levels of consumer rebates across electric and gas utilities.
- **Reforming industry allocations.** Policymakers could consider additional changes to the formulas used to award free allowances to trade-exposed industries to more closely reflect the risk of leakage on an industry-specific basis, or by prioritizing allocations for industries that are anticipated to maintain substantial activities in a decarbonized future while de-prioritizing allocations for industries that are expected to diminish or shift focus over the course of the state's energy transition.
- **Balancing outcomes for undersubscribed auctions.** When demand is lower than supply at quarterly auctions, the current rules prioritize the sale of utility consignment allowances above the sale of state-owned allowances. This ensures that utility transfers are given first priority, but it leads to instability in Greenhouse Gas Reduction Fund revenues. The legislature could balance these interests, such that each type of funding source is affected equally in undersubscribed auctions (see pages 14-16 in the 2020 IEMAC Report).

It is important to emphasize that for any given set of market design choices — issues that include at which level to set the minimum and maximum market prices, and how binding or lax to make compliance instrument supplies in relation to covered emissions — the question of how to distribute value through the allocation of allowances and issuance of offset credits remains. To date, these design questions have largely been delegated to CARB, though in the future they could be guided or even directly specified by statute. Nevertheless, the IEMAC observes that, given the complexity and interactions between policy design details, legislative intervention that directs outcomes for specific regulatory formulas or parameters risks creating unintended consequences and suboptimal outcomes.

Chapter 4. Market Design to Strengthen California's Climate Policy Portfolio

Dallas Burtraw and Danny Cullenward

Every five years the Air Resources Board's Scoping Plan process provides a blueprint for California's climate policies. The Plan assesses the emissions pathway under status quo policies, describes the state of technology, and where technology advancements are required. Traditionally, the Plan does not prescribe policy, but it does describe the contribution that regulatory actions are expected to make to the state's climate outcomes.

Although the carbon market is anticipated to play a fundamental role in achieving the state's goals, sector-specific regulatory policies have been and will continue to be critical to environmental outcomes. However, regulatory ambition may be intermittent and the outcomes from regulation are uncertain. Regulatory targets embodied in efficiency performance standards for buildings and vehicles are typically effective in improving the efficiency of energy use, but sector-specific emissions are not constrained. Secular trends in economic activity, fuel prices, and behavior are inherently uncertain and strongly influence outcomes; hence, ***uncertainty about emissions outcomes and timelines in the regulatory domain is inherent***.

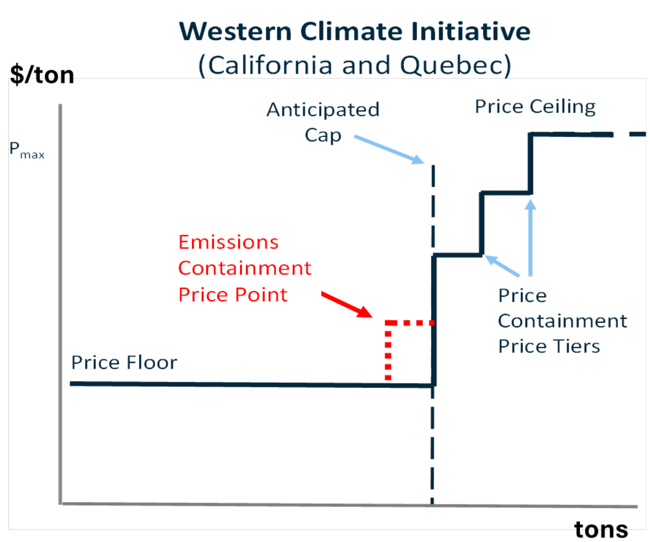
The carbon market interfaces with regulations in several important ways. The declining emissions cap boosts confidence that emissions reductions will be achieved over time at covered sources. The emissions market is generally understood to be more cost effective than prescriptive regulation (see chapter 2 on cost containment), providing benefits to the state's economy as a leading instrument to achieve the state's climate goals. The price provides information to investors and consumers and shapes expectations about the future. The market provides revenue for investments to accelerate emissions reductions and to address other social concerns. And importantly, as part of the climate policy portfolio, the price in the carbon market responds to the variable performance of regulations and economic trends.

The dilemma is that the carbon market does not efficiently amplify and may diminish the performance of sector-specific regulations. When state regulations, measures by local government, firms, or individuals are effective in mitigating emissions they reduce the demand for emissions allowances (see chapter 2 on cost containment). Unfortunately, over a broad range of outcomes, successful regulations do not affect the number of emissions allowances available in the market and hence do not affect the emissions that occur. This phenomenon is known as the "waterbed effect" because the emissions cap acts like the volume in a waterbed; that is, when regulatory policies push emissions down in one place, emissions rise at a covered entity somewhere else in the market. The price is affected by regulatory activities outside the market, but the emissions outcome is not affected, thus eroding the contribution from regulations.

The Western Climate Initiative carbon markets (California, Quebec, and Washington) and the Regional Greenhouse Gas Initiative have measures to ameliorate extreme fluctuations in allowance price through the auction price floor (minimum price in the auction) if prices reach very low levels and allowance reserves that make additional allowances available if the price reaches very high levels. In California, however, price movements over the broad range between the price floor price of $24 and the tier one reserve price threshold of $56 yield no changes in emissions.

In annual reports since 2018, this committee has described an adjustment to market design that can importantly improve the alignment of the market and regulations within a more strategic policy framework. This market feature is sometimes named an Emissions Containment Reserve. In its simplest and most practical form, ***an Emissions Containment Reserve would add a price step at about $40, midway between the price floor and reserve price threshold***. As illustrated in Figure 1, this price step would apply to a fraction (e.g., 10%) of the allowances that would otherwise enter the market, and it would constrict allowance supply by removing these allowances from sale in the auction if the auction clearing price were below the price step. Implementation of this feature would be very simple and precisely mirror the existent price floor mechanism.

Figure 1: An illustration of the allowance supply schedule with an Emissions Containment Reserve



Importantly, ***an Emissions Containment Reserve would be triggered only if and when allowance prices are low***, accelerating emissions reductions when prices are low, and magnifying the cost effectiveness of the carbon market. In this way, the Reserve would support the affordability of California's overall climate policy portfolio.[16]

A related concern is the accumulation of a large privately held allowance bank, now greater than 379 million tons[17] and greater than one year's allowance supply. Although there is little theory to describe the optimal size of the bank and that size depends on expectations about the future of the market, a very large bank conveys a sense that the allowance supply is too generous and that future emissions reductions will be hard to achieve because the bank provides an ample allowance supply that will re-enter the market. The Regional Greenhouse Gas Initiative has responded to a comparable situation with administrative adjustments to reduce the supply of newly auctioned allowances to absorb the private bank into the market. The European Union responded with the adoption of a quantity-triggered approach to automatically adjust allowance supply in response to the bank (the number of allowances in circulation). The EU's quantity-based approach is complicated and may be less efficient according to most economic appraisals than a price-based approach such as an Emissions Containment Reserve because the quantity-based adjustment is delayed and difficult to predict; nonetheless, the quantity-based approach has enabled a reduction in the size of the bank and a substantial increase in allowance prices in the EU.

In response to the challenge of implementing repeated adjustments to supply, the Regional Greenhouse Gas Initiative in 2021 implemented an automatic price-based adjustment to supply as an Emissions Containment Reserve. Washington also adopted this feature in legislation establishing its carbon market, but the feature was suspended largely in anticipation of eventual linking with California, which has not adopted this feature.

Paradoxically, ***a reduction in allowance supply to support the allowance price will likely yield an increase in auction revenue.*** The value of allowances is determined by their number multiplied by their price. Much like reduced supply in commodity markets can increase the commodity's value, if an Emissions Containment Reserve were triggered leading to reduced allowance supply it would yield an increase in allowance value. Three times in 2023 the auction price fell below the proposed price trigger level, and three times again in 2024. Based on modeling from Roy et al. (2024) and Burtraw and Roy (2025), ***the absence of the Emissions Containment Reserve has lost over $240 million in benefits for ratepayers and the Greenhouse Gas Reduction Fund***

[16] Statutory guidance to pursue cost effective implementation and to accelerate emissions reductions can be found in HSC 38560 ("... achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions …") and HSC 38562.2(c)(1) ("Achieve net zero greenhouse gas emissions as soon as possible …").

[17] CARB [Q4 2024 Compliance Instrument Report]

on average in six auctions in 2023 and 2024. That is, the lost opportunities for revenues to the Fund accumulate to almost $1.5 billion since 2023 (2023$).

For an Emissions Containment Reserve to benefit the Greenhouse Gas Reduction Fund, ***it is important that adjustments to supply accrue not just by constricting auctioned supply but also across all channels through which allowances enter the market,*** including allowances consigned by utilities and free allocation to industry. Currently, utility-consigned allowances sell before state-owned allowances, and hence sell first if the price falls to the price floor. Utility consigned allowances can be treated symmetrically with auctioned allowances by ending the priority sale of consigned allowances in the auction, which would create a symmetric treatment for these allowances and state-owned allowances. Free allowances to industry can be adjusted as part of the annual true-up that already occurs to adjust free allocation to changes in production at industrial facilities.

A different approach to realize greater emissions reductions when allowance prices are low would be to raise the auction price floor, which would shorten the vertical portion of the allowance supply curve in Figure 1 and reduce the influence of the waterbed effect. If the auction clearing price were to fall to the price floor, then allowance supply would be reduced. As with an Emissions Containment Reserve, for this reform to preserve the share of allowance value accruing to the Greenhouse Gas Reduction Fund it would be important that adjustment to supply occur for all channels through which allowances enter the market. An advantage of introducing an additional price step as an Emissions Containment Reserve is that it fills out a price-responsive allowance supply schedule which preserves and enhances the role of the market in price discovery over a wider range of outcomes (Roberts and Spence 1976; Burtraw et al. 2022). An increase in the price floor could be coupled with an Emissions Containment Reserve. We understand that a change in the price floor or the introduction of an Emissions Containment Reserve would not require legislative authorization.

A related opportunity for reform exists in the way sales from the Allowance Price Containment Reserve would be implemented if the mechanism were triggered by a high auction clearing price. Although prices have never reached a level that would trigger a sale from the Reserve, regulations imply that sale from the Reserve would occur weeks after the auction if the auction price reached the price trigger threshold. This separation in time is unnecessary and makes possible the cycling of allowance prices and potential strategic behavior. In contrast, the allowances from the Cost Containment Reserve in the Regional Greenhouse Gas Initiative are available instantaneously in the auction if the price reaches the threshold, analogous to the operation of the current price floor mechanism and the Emissions Containment Reserve in that market.

A price-triggered Emissions Containment Reserve and a parallel rule-based approach to the Allowance Price Containment Reserve would provide mechanisms like the current price floor that could be anticipated by market participants and implemented automatically. The mechanisms would not be dependent on discretionary decisions and procedures that are challenging to implement in the moment, and which can appear to observers as arbitrary. For example, recently Washington made an administrative decision about the number of allowances and price level for implementing its Allowance Price Containment Reserve, which led some market participants to unexpectedly lose substantial value and may have weakened overall market confidence. In contrast, a rule-based approach decided ex ante could be anticipated, would be perceived as fair, and would boost confidence in the performance and durability of the market.

In summary, automatic adjustments to allowance supply are necessary to better align incentives in the market with regulatory initiatives. Rule-based approaches triggered by the auction price like the current price floor, a new Emissions Containment Reserve, and a reformed Allowance Price Containment Reserve boost confidence in the market and the credibility of the state's long-term goals. It would enable the market to automatically respond to inherent uncertainty in economic conditions and the state's prominent regulatory programs. Reform of California's market design to better align the market with regulation is important to California's goals and can be a model for policy globally.

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Chapter 5. Environmental Justice Options in California's Cap-and-Trade Program

Katelyn Roedner Sutter & Meredith Fowlie

Introduction

The Environmental Justice Advisory Committee (EJAC) at the California Air Resources Board (CARB) has raised numerous concerns about the cap-and-trade program over the years.[18] Broadly, these include concerns about the program's failure to deliver tangible environmental improvements to disadvantaged communities; concerns that the use of offsets will reduce the extent to which industrial point sources invest in abatement that can improve environmental quality in disadvantaged communities; and concerns that the allocation of free allowances to industrial facilities (which tend to be located in or near communities already overburdened by environmental, socioeconomic, and health challenges) reduces the incentives to invest in pollution reductions in these communities.

More recently, EJAC has issued a resolution, including a number of recommendations to reform the GHG cap-and-trade program, articulated in the document titled "Environmental Justice Priorities for an Extension of the Cap-and-Trade Program". EJAC has explicitly asked to be included in all conversations around this resolution as full partners so that EJ groups can articulate concerns and priorities as negotiations proceed. Respecting this explicit request, we do not endeavor to make any policy recommendations with respect to this resolution. Instead, the chapter acknowledges the important concerns of environmental justice groups. It offers some observations around how some of the EJAC recommendations could interact with cap-and-trade program design issues discussed elsewhere in this report. Finally, it underscores the importance of engaging directly with EJAC in discussions of their resolution.

In what follows, we briefly review some of the recent research that investigates how emissions reductions under the GHG cap-and-trade program have impacted local air quality in California communities. We then consider a subset of EJAC recommendations that specifically pertain to GHG market design reforms. We note that EJAC has asked that their recommendations not be "taken piecemeal", but rather as a holistic set of reforms that work together. However, several of the EJAC recommendations fall well outside the scope of IEMAC expertise. With the discussion that follows, we do not make any policy recommendations. Our goal is to help inform elements of the larger

[18] https://ww2.arb.ca.gov/sites/default/files/2024-10/DRAFT%20EJAC%20cap%20and%20trade%20resolution_October%202024.pdf

conversation around how carbon market-related EJAC recommendations could interact with the cap-and-trade program design and operations.

Recent Research[19]

EJ advocates have raised important concerns about the impact of California's cap-and-trade program - or lack thereof - on local air pollutants such as sulfur dioxide and nitrogen oxides. Although the GHG cap-and-trade program was not designed to address local air pollution problems, GHG abatement can deliver air quality improvements if reductions in GHG emissions are accompanied by reductions in local criteria pollution.

There is a well-documented positive correlation between greenhouse gas emissions and local air emissions from industrial sources in California. On average, when an industrial facility reduces its GHG emissions, emissions of local criteria pollutants are also reduced. However, the figure below shows that this positive correlation is quite noisy. More specifically, this figure shows how emissions of GHGs and criteria pollutants from industrial and electricity generating sources in California have changed between 2013 (the start of the cap-and-trade program) and 2020. For 30% of these facilities, reductions in GHG emissions are associated with *increases* in SO2 emissions (top left). In the lower right quadrant, 17% of sources increased GHG emissions while decreasing criteria emissions over this period. This figure helps to illustrate the positive - but noisy - correlation between point-source GHG emissions and emissions precursors to local air pollution. Given the nature of this correlation, policies targeting GHG emissions are a relatively indirect and blunt tool for addressing local air quality concerns.

Decades of regulations targeting local air pollution more directly have failed to eliminate local pollution exposure inequities in California (and across the country). Given these persistent inequities, California policymakers should be looking for every opportunity to improve conditions in disadvantaged communities. Along these lines, EJAC has made a number of recommendations to reform the GHG cap-and-trade program.[20]

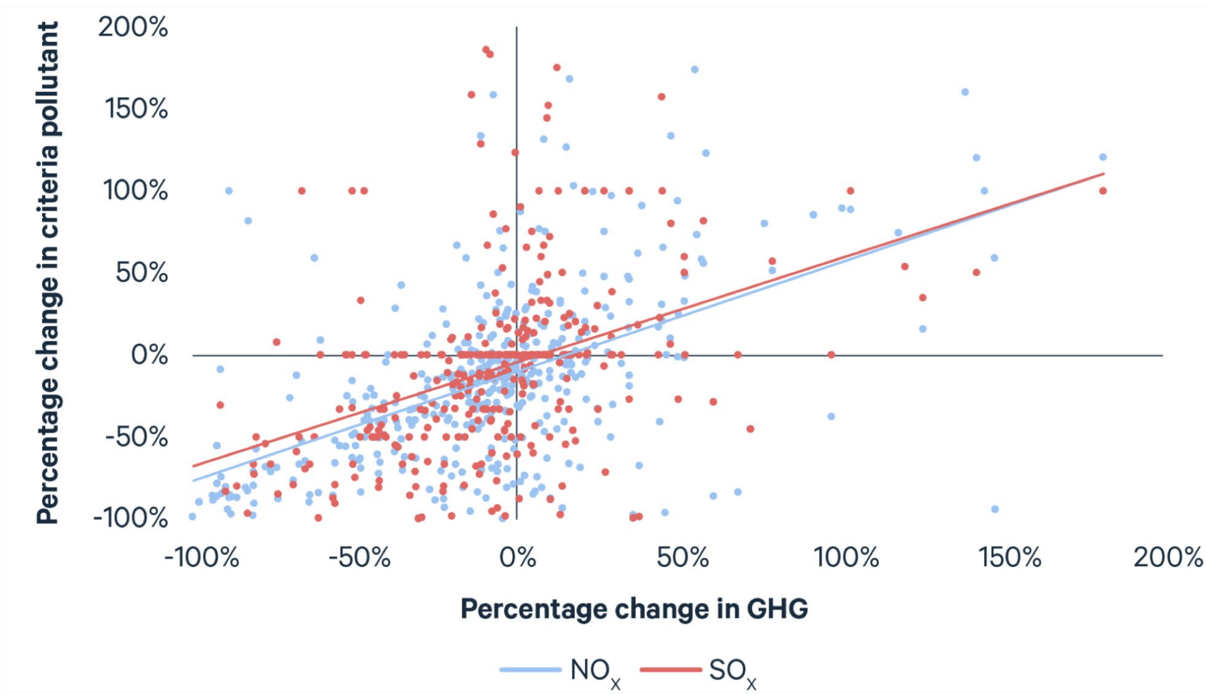
Researchers have been analyzing data from California in order to retrospectively assess how the GHG cap-and-trade program has impacted facility-level GHG emissions and downwind local air quality. Isolating the causal impacts of a cap-and-trade program on emissions outcomes requires constructing credible estimates of what pollution levels would have looked like had the program not been implemented. This is inherently challenging, particularly when multiple climate policies and programs are implemented at the same time. These challenges notwithstanding, several recent papers have endeavored to isolate and estimate the effects of California's GHG cap-and-trade

[19] This is not intended to be an exhaustive review of the research into the cap-and-trade program's impact on environmental justice communities but the latest installments in an ongoing body of work.

[20] EJAC resolution

program on air quality in environmental justice communities. Appendix B summarizes findings from recent research on this topic.

Figure 1. Percentage Change in NO_x–SO_x GHG Emissions in California, 2013–2020



Note: NO_x = nitrogen oxides; SO_x = sulfur oxides.

Notes: This figure summarizes emissions data from all California facilities that report emissions. Changes in annual GHG emissions (between 2013 and 2020) are measured on the horizontal axis. The vertical axis measures changes in nitrogen oxides and sulfur dioxide. Source: Burtraw and Roy, 2023.

Overall, researchers have found evidence that the GHG cap-and-trade program has delivered reductions in local air pollution, although they disagree on the extent to which these reductions have mitigated pre-existing inequities in exposure to harmful local pollution.

Environmental Justice Advisory Committee (EJAC)

In what follows, we consider changes to the cap-and-trade program proposed by EJAC, as well as potential trade-offs and additional design options. EJAC has requested that environmental justice groups be included in conversations regarding these recommendations as full partners. However, we view this annual report as an opportunity for IEMAC to offer a perspective on those recommendations that pertain directly to market design issues.

EJAC Proposed Program Reform #1: Elimination of Free Allowances in the Industrial Sector

While almost half of allowances in the cap-and-trade program are sold through quarterly auctions administered by CARB, 30-45% of allowances are distributed to covered entities at no cost.[21] As we explain in chapter 3, these output-based allowance allocations are designed to mitigate emissions "leakage" (i.e. the movement of economic activity and associated emissions out of state) in industrial sectors deemed to be exposed to leakage risk. About 10–15% of allowances are freely given to regulated industrial emitters in emissions intensive and trade exposed (EITE) sectors. Output-based allowance allocation acts like a production subsidy and can incentivize industrial production within California which helps to mitigate emissions leakage.

To determine how many free allowances industrial facilities receive, CARB considers four variables: (1) an assistance factor (which was initially intended to reflect the degree of leakage risk) (2) product benchmark (a sector-specific efficiency benchmark defined in terms of emissions intensity) (3) the cap decline factor (the rate at which the economy-wide cap declines), and (4) a facility's overall output or production.[22] CARB and the Legislature could reduce the number of allowances allocated to industrial sources by adjusting one or more of these variables.

Advantages of eliminating free allowances

Reducing the quantity of allowances allocated to industrial sources could increase revenues available for other uses. Taking 2025 EITE allocations as an example, if the roughly 32 million[23] freely allocated allowances were instead sold at auctions at the November 2024 settlement price of $31.91, this translates to over $1 billion in additional revenue to the GGRF. Had these revenues flowed to the Greenhouse Gas Reduction Fund, they could have enabled more investments in environmental justice and other priorities.

Disadvantages of Eliminating Free Allowances

Eliminating free allowances could have detrimental impacts on the state's ability to limit leakage. The primary justification for providing free allowances to industrial sources is to minimize the extent to which industrial activity – and associated GHG emissions - moves out of state to avoid having to comply with the cap-and-trade program. Output-based allocations effectively subsidize production at industrial facilities under the cap. This provides an incentive to keep industrial production under the cap versus moving

[21] https://ww2.arb.ca.gov/sites/default/files/2021-01/CT_Allowance_FactSheet_Jan2021.pdf

[22] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation/allowance-allocation-industrial

[23] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation

production (and associated emissions) out of the state. Eliminating this production incentive could increase emissions leakage and undermine the integrity of the cap-and-trade program.

Options for Reforming Free Allocation of Allowances

Policymakers could consider alternatives that would reduce the number of allowances to EITE sectors by updating the criteria used to determine allocations:

1. Reauthorize the California Air Resources Board (CARB) to set assistance factors based on leakage risk, rather than assuming a uniform 100% risk across all facilities with no decline over time. Under the 2017 cap-and-trade extension, legislators set leakage factors for all emissions-intensive trade-exposed (EITE) sectors at 100%, a departure from the original program where CARB had set lower assistance factors for sectors deemed to face lower levels of leakage risk. A recalibration of assistance factors to reflect actual leakage risk could support targeted leakage risk mitigation where it is most needed.
2. Implement a steeper cap adjustment factor rather than having all facilities' allocation follow the economy-wide cap decline.
3. Direct CARB to update product efficiency benchmarks to accurately reflect the latest technology. The standards for efficiency are several years out of date. Updating the benchmarks would help ensure that facilities are incentivized to adopt best practices.

EJAC Proposed Program Reform #2: Elimination of Offsets

Offsets allow covered entities to meet a portion of their emissions reduction requirements by investing in projects that reduce or remove greenhouse gases in sectors not directly regulated by the program. Currently, offset usage is capped at 4% of an entity's compliance obligation, but actual utilization remains well below this limit. In the 2021-2023 compliance period, offsets accounted for 3.1% of overall compliance obligations, with a few entities relying heavily on offsets while most use none at all.[24] The offset usage limit increases to 6% of an entity's compliance obligation in 2026.

Advantages of Eliminating Offsets

Eliminating offsets could result in increased carbon market revenues assuming facilities that currently purchase offsets start purchasing allowances instead. This could also incentivize more direct reductions in greenhouse gas emissions at compliance entities. It is not clear where these additional reductions would occur, as the facilities that would

[24] https://ww2.arb.ca.gov/sites/default/files/2024-12/nc-CP4compliancereport.xlsx

have used offsets for compliance purposes could alternatively purchase GHG allowances to satisfy their compliance obligations, unless their ability to use allowances for compliance purposes has also been eliminated (we return to this below). Eliminating offsets would also increase emission reductions in California that count toward statewide greenhouse gas emissions limits, rather than support climate mitigation in sectors or states that do not currently count.

Disadvantages of Eliminating Offsets

Offsets provide significant funding for Tribes in California which sell offset credits into the market, such as the Yurok Tribe. Eliminating offsets as a compliance option would reduce financial support for these projects, and the flow of resources to Tribes, absent alternative funding mechanisms, as discussed in Chapter 7.

More broadly, the offset market is one of the key ways in which California finances investments in nature-based climate solutions, which are vital for mitigating the worst impacts of climate change and helping landscapes and communities adapt. The 2022 Scoping Plan and the 2024 Nature-Based Climate Solutions Targets published by the California Natural Resources Agency both include the use of markets, among other strategies, to achieve necessary climate outcomes.[25] Eliminating offsets could weaken the financial incentives for these projects, undermining their potential to deliver climate and societal benefits.

These cons would arise if offsets were eliminated without a simultaneous commitment to replace offsets with an alternative funding mechanism. However, if the use of offsets is further limited or eliminated as part of a broader set of reforms that also provides dedicated funding to Tribes and Nature-Based Climate Solutions, then these disadvantages could be reduced or avoided — contingent on the stability of new funding resources.

Options for Offset Reform

To maintain the benefits of offsets while addressing equity concerns, policymakers could explore alternatives to refine and enhance their use. Options for reform or replacement of the offset program are explained at greater length in Chapter 7.

1. Further reduce the percentage of a compliance obligation that a covered entity can meet through offsets. The offset usage limit increases to 6% of an annual compliance obligation in 2026, with half of those offsets required to provide DEBs

[25] https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/Californias-NBS-Climate-Targets-2024.pdf

to California. A post-2030 program could revisit these limits or reconsider the split between DEBs and non-DEBs offsets.

2. Relatedly, California could establish a Tribal-specific offset compliance option. Washington State provides an example, where the offset usage limit is 5% annually, with an additional 3% allowed if they are Tribal offsets.
3. California could retire allowances from the program (permanently removing them), equal to the number of offsets turned in for compliance each year. This is sometimes referred to as counting offsets "under the cap" because the emissions cap is effectively lowered to compensate for offset usage.
4. Offsets could be replaced with dedicated funding from the Greenhouse Gas Reduction Fund (see Chapter 7), which would resolve concerns related to the efficacy of offset use and could help address local air quality disparities, though could also require significant resources from GGRF to support Tribes and Nature-Based Climate Solutions.
5. CARB could update regularly the compliance offset protocols to ensure they reflect the best available science.

EJAC Proposed Program Reform #3: No Trade Zones or Facility-Level Emission Caps

The 2023 IEMAC report discussed no trade zones and facility-level emission caps at length.[26] The stated goal of these proposed reforms, both of which would limit the compliance flexibility for a subset of regulated entities, is to ensure that facilities in disadvantaged communities reduce GHG emissions. There are a variety of ways that this objective could be met, but all would reduce the compliance flexibility of sources in targeted areas.

Advantages of Reduced Compliance Flexibility

Facility-specific caps could provide important benefits. Specifically, reducing the extent to which facilities in certain local communities where GHG emissions reductions have not kept pace with the state's average rate can achieve compliance via the purchase of GHG allowances, could result in local air pollution reductions in those locations if the imposed compliance limits are binding. As noted above, there is a positive correlation (on average) between global greenhouse gas pollutants and localized air pollution on average. As such, reductions in GHG emissions at targeted facilities could result in direct local air quality benefits for the most polluted communities.

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[26] https://calepa.ca.gov/wp-content/uploads/sites/6/2023/02/2022-ANNUAL-REPORT-OF-THE-INDEPENDENT-EMISSIONS-MARKET-ADVISORY-COMMITTEE-2.pdf see pages 14-17

Disadvantages of Reduced Compliance Flexibility

The inherent compliance flexibility of a market-based approach facilitates coordination of cost-effective GHG emissions reductions. Allowing a facility to determine their own compliance strategy - reducing emissions on-site, buying and selling allowances, or purchasing offsets - based on their facility-specific abatement costs means that every covered entity can find the lowest-cost pathway to complying with an economy-wide goal. If restrictions on compliance flexibility are binding, the costs incurred to comply with the program will increase. By how much would depend on the design of the trading limits and the relative costs of the impacted facilities. Increases in program compliance costs- and thus allowance prices- would be passed on to California consumers.

Research from Resources for the Future (RFF) investigates how the allocation of permitted GHGs might have been different had a form of facility-specific caps been implemented in the past. Because the rate of GHG emissions reductions achieved within disadvantaged communities has, on average, outpaced the state average rate of GHG reductions, these authors estimate that facility-specific caps would have a limited effect on aggregate outcomes. However, within communities where emissions reductions have not kept pace with the state's average rate, facility-specific caps could provide important benefits.

It is important to keep in mind that this RFF analysis is retrospective. Looking ahead, we will need a more stringent cap to meet our future GHG emissions reduction targets. In a tighter carbon market, source-specific trading limits could have more significant effects on emissions, emissions leakage, and abatement costs.

Another important consideration is that any changes made to limit compliance flexibility of specific market participants could interact in significant ways with other important features of the program, including the price floor and ceiling discussed in Chapter 4. Interactions between facility-specific compliance limits and cost containment mechanisms and other market design features (e.g. leakage mitigation) need to be weighed carefully to avoid unintended consequences.

Alternatively, policymakers could more directly address local air pollution problems in disadvantaged communities by implementing other EJAC recommendations including:

1. Strengthen the Community Air Protection Program established by AB 617
2. Conducting statewide audits of facilities operating within environmental justice communities

Conclusion

EJAC has asked to be included in conversations around these recommendations as full partners so that EJ groups can articulate concerns and priorities as negotiations proceed. With this in mind, this chapter does not make policy recommendations. Our goal with this chapter was three-fold. First, we acknowledge the important concerns of environmental justice groups around local air pollution in their communities. Second, we aim to elevate the consideration of EJAC recommendations. Third, we hope the perspectives offered in this chapter can inform future discussions around EJAC priorities that pertain to carbon market design.

Appendix B

"*Do environmental markets cause environmental injustice? Evidence from California's carbon market*" by Danae Hernandez-Cortes and Kyle Meng (2023). This research focuses on a subset of compliance entities covered by California's cap-and-trade program and compares emissions at these facilities with emissions trajectories at observationally similar facilities that are not covered by the program. The authors detect a significant difference in emissions between these "control" and "treatment" groups. They then model how that difference maps onto local air emissions using a pollution dispersion model from the National Oceanic and Atmospheric Administration to map estimates of the emissions impacts of cap-and-trade to downwind air quality impacts. The authors estimate that "during 2012-2017, the cap-and-trade program reduced emissions annually at a rate of 9%, 5%, 4%, and 3% for GHG, PM 2.5, PM10, and NOx, respectively, for the average sample regulated facility."[27]

In "*Cap and trade: Understanding the research and remedies*" Michael Ash, Manuel Pastor et al (2024) critically review the Hernandez-Cortes and Meng paper. These authors assert that they misidentified control and treatment groups by failing to reflect changes in the status of whether individual polluters were covered by the California cap-and-trade program. Ash and Pastor run several alternative regressions with control and treatment groups they deem more appropriate. In a recent presentation, Dr. Manuel Pastor explained that with these alternative regressions "the estimated changes are smaller and close to what we might have expected". Specifically, Dr. Pastor showed that in their analysis the C&T program reduced emissions annually at a rate of 3.2%, 2.3%, 0.7%, and 0.0% for GHG, PM 2.5, PM 10, and NOx. These values indeed show smaller reductions than presented by Hernandez-Cortes and Meng.[28]

Glenn Sheriff in "*California's GHG Cap-and-Trade Program and the Equity of Air Toxic Releases*" (2024) uses several empirical strategies, including a "difference-in-difference"

[27] https://www.sciencedirect.com/science/article/pii/S0047272722001888

[28] https://ww2.arb.ca.gov/sites/default/files/2024-07/CARB_EJAC_2024_07_18_v_03%20RMF%20%28ADA%20Checked%20and%20updated%29.pdf

approach as employed by Hernandez-Cortes and Meng, in combination with a pollution dispersal to estimate the impact of California's cap-and-trade program on air toxic releases as reported through EPA's Toxic Release Inventory. The author finds that "minority communities experience a relative reduction in cumulative exposure from [air toxic releases]" caused by the California cap-and-trade program.[29]

[29] https://www.journals.uchicago.edu/doi/10.1086/725699

Chapter 6. Carbon Management in California's Cap-and-Trade Program

Katelyn Roedner Sutter & Brian Holt

Introduction

Carbon management is an issue of growing interest among California policymakers and regulators. While many of the policy issues around carbon management are beyond the traditional domain of the carbon market, some issues could soon interact with the carbon market in important ways. Looking forward, carbon management will likely become a more central focus of carbon market design and implementation. The 2023 Independent Emissions Market Advisory Committee report dealt with point-source carbon capture and subsurface carbon storage in detail and remains an important narrative of the opportunities and challenges related to carbon capture and storage.[30] **In this chapter, IEMAC aims to situate various carbon management strategies within the carbon market discussion, and surface considerations for policymakers as they determine the future shape and priorities of California's cap-and-trade program.**

It is important to understand the various carbon management strategies and which problem they aim to solve. Point source carbon capture (sometimes referred to as CCS or CCUS) is used to *reduce* the carbon dioxide emissions coming out of a facility.[31] This is emission reduction technology that is designed to directly reduce pollution going into the atmosphere. Carbon dioxide removal (CDR) is used to *remove* legacy carbon dioxide pollution from the atmosphere. Direct air capture (DAC) is a common example, but removal strategies include a wide range of technology- and nature-based climate

[30] https://calepa.ca.gov/wp-content/uploads/sites/6/2024/02/2023-ANNUAL-REPORT-OF-THE-IEMAC-final.pdf see pg 24-28.

[31] https://www.edf.org/sites/default/files/documents/carbon%20removal%20vs.%20carbon%20capture%20fact%20sheet_FINAL.pdf. A more comprehensive discussion of the wide range of approaches is available at https://www.google.com/url?q=https://nap.nationalacademies.org/read/25259/chapter/1&sa=D&source=docs&ust=1736438226719114&usg=AOvVaw3iwbs0GeAKRTLAE3mz2CpL.

solutions as well.[32] CDR is not an emission *reduction* strategy, but rather removes pollution that is already impacting the climate. Both are considered carbon mitigation strategies. The carbon dioxide captured from facilities and removed from the atmosphere through DAC is most commonly stored underground, which is discussed in further detail in the 2023 IEMAC report.

The 2022 Scoping Plan developed by the California Air Resources Board assumes that CCS will be deployed to achieve 85% reductions below the 1990 emission level by 2045 and that CDR will be deployed to reach net zero emissions by 2045. The 2022 Scoping Plan shows that point source carbon capture at industrial and electricity generating facilities is anticipated to capture 13 million metric tons carbon-dioxide-equivalent ($MMTCO_2e$) by 2030 and 25 $MMTCO_2e$ by 2045, with industrial capture declining across the 2030s and an additional 17 $MMTCO_2e$ deployed in a single year (2045) in the power sector. The Scoping Plan assumes CDR deployment will total 7 $MMTCO_2e$ in 2030 and 75 $MMTCO_2e$ by 2045.[33] The Scoping Plan further assumes that technological CDR does not have any net energy consumption and that it is fully paid for by an unspecified mechanism, despite necessary funding reaching more than about $30 billion per year by the late 2030s.[34]

Governor Newsom has also endorsed CCS and CDR, directing CARB to accelerate development of projects with a target of 20 $MMTCO_2$ for 2030 and 100 $MMTCO_2$ for 2045.[35] California policy also supports nature-based climate interventions across landscape types, but anticipates that even with these strategies, carbon stocks on California's natural and working lands will decrease in the coming decades and constitute an approximately 7 $MMTCO_2$ per year source, on average, through 2045.[36] Beyond California, the Intergovernmental Panel on Climate Change (IPCC) recognizes that CDR is required to stay below 1.5 degrees of warming, though also emphasizes that CDR is not a substitute for significant emission reductions.[37]

We must recognize that as California gets closer to the 2045 goal of 85% emission reductions below the 1990 level and net-zero emissions, that the cap-and-trade program will become less about coordinating cost-effective emissions reductions and

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[32] Ibid.

[33] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf .

[34] https://ww2.arb.ca.gov/sites/default/files/2022-11/SP22-MODELING-RESULTS-E3-PPT.pdf Slide 23

[35] https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf

[36] https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/Californias-NBS-Climate-Targets-2024.pdf

[37] https://www.ipcc.ch/report/ar6/wg3/downloads/outreach/IPCC_AR6_WGIII_Factsheet_CDR.pdf

more about coordinating cost-effective carbon management. That is, there is likely to be a certain amount of residual emissions that must be captured or removed and stored permanently. As such, there will need to be regulatory direction and certainty. However, the current cost per ton of both captured and removed carbon dioxide ($180/ton to over $1000/ton, though this is likely to fall) is notably higher than the current carbon price (in the low-to-mid-$30s), and there remains uncertainty over technological readiness and efficacy. Taken together, in the near-term carbon management would be unlikely to play a significant role in the cap-and-trade program, even if other regulatory barriers were removed. Nonetheless, rules established in the near term will frame and constrain long-term regulatory design as well as investment in innovation, so understanding the role of various carbon management strategies, as well as potential options for action, is important.

It is also important to be realistic about the scale of the funding needs associated with the CDR deployments assumed in the 2022 Scoping Plan. CARB projects that the cost of deploying the level of CDR it selected will reach tens of billions of dollars per year, peaking at nearly $30 billion by 2040, but did not identify a funding source for this money.[38] Whatever the policy instrument or instruments used to support the early deployment of CDR in California, the scale of what was assumed in the 2022 Scoping Plan is significant and will require substantially more financial support than is available in any one policy instrument in California today.

While the focus of this chapter is the potential nexus between the cap-and-trade program and carbon management, the compliance market is not the only avenue Legislators may wish to consider to develop high-integrity carbon management strategies. Options include:

- Direct public funding of CDR projects, either through the Greenhouse Gas Reduction Fund or another funding source. State investment could help ensure greater accountability and oversight of nascent technologies, environmental integrity and community impacts. However, it could also be hard to appropriately scale with public money given budget limitations to achieve net-zero emissions no later than 2045 and maintain net negative emissions thereafter.
- An incentive-based approach such as state tax credits for developing or investing in supported CDR projects. This could be similar to the approach the federal government has taken under the Inflation Reduction Act (IRA). The IRA and related Bipartisan Infrastructure Law (BIL) have billions of dollars allocated to credits for both natural and engineered carbon removal strategies.[39] This option

[38] E3 Inc., CARB Scoping Plan: AB32 Source Emissions Final Modeling Results (Oct. 28, 2022) at slide 23, https://ww2.arb.ca.gov/sites/default/files/2022-11/SP22-MODELING-RESULTS-E3-PPT.pdf.

[39] https://www.wri.org/update/carbon-removal-BIL-IRA

would rely on public finance, similar to the direct public funding option above; but it would delegate the selection of projects to market forces, similar to the stand-alone program described in the next bullet point.

- Establish a stand-alone program whereby identified emitters or sectors are required to procure CDR in addition to existing emission reduction requirements. This would require regulatory agencies to determine standards for which types of engineered and nature-based carbon removal strategies are approved, under what conditions, and how to calculate CDR outcomes net of the emissions involved in CDR projects' construction and operation. While this moves the cost burden onto emitters rather than directly on the state budget, it does potentially mean less direct control and oversight over specific projects.
- No further action beyond full implementation of SB 905 (Caballero, Skinner, 2022). Policymakers could decide this is sufficient regulation of point source carbon capture and underground storage. Even if the cap-and-trade regulations clarified whether or not CCS projects' captured emissions constitute a compliance obligation, the incentive produced by the cap-and-trade program's allowance prices may be too low to justify investment in CCS or CDR projects given their current and expected future costs.

There are numerous variations of each of these options, but broadly speaking, California will eventually need to decide if it wants to incorporate carbon management within the carbon market and if so, then how. The answer need not be the same for point source carbon capture and carbon removal, and it is likely more than one strategy will be needed to support the necessary scale of carbon management. If managed outside of the carbon market, California will also eventually need to determine another mechanism to ensure that there are sufficient removals by mid-century to meet the 2045 net-zero goal and maintain net negative thereafter.

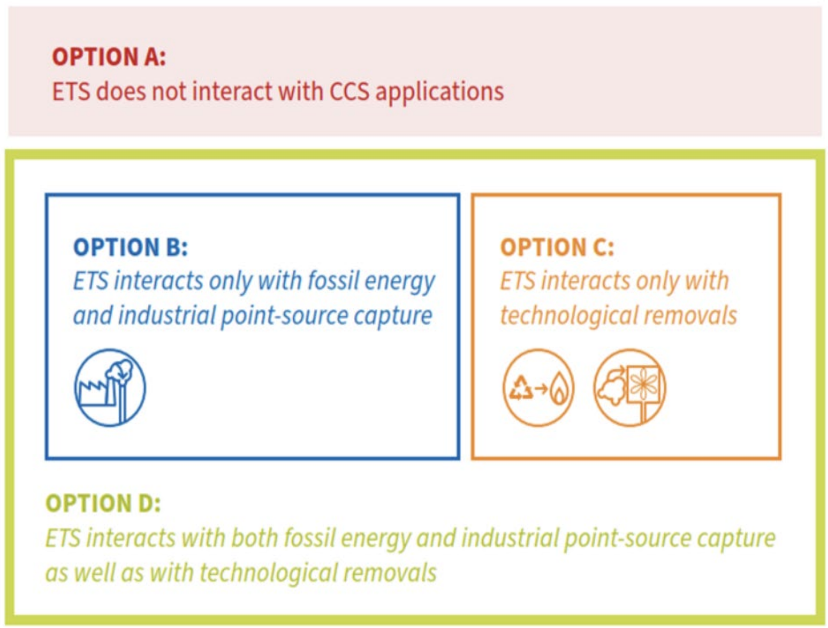
The figure below, taken from a 2023 report, provides a conceptual framework for thinking about alternative ways to define the relationship between carbon management and carbon markets. Option A is no interaction between carbon management and the carbon market, Option B is point-source carbon capture is incorporated into the carbon market, Option C is technological CDR is incorporated, and Option D is both CCS and technological CDR are incorporated into the market.

By way of example, the European Union Emissions Trading System (EU ETS) and the United Kingdom Emissions Trading System (UK ETS) both currently allow for captured and stored emissions to be subtracted from a covered entities' compliance obligation, though as of January 2023 no facilities were using these provisions of the ETS.[40] These are examples of Option B. No system currently allows for mechanical carbon dioxide

[40] Ibid. 10

removal such as DAC, Option C. California's program would currently be classified under Option A.

Figure ES. 4 – Four options for interaction between ETSs and CCS



Source: S. La Hoz Theuer and A. Olarte. (2023). Emissions Trading Systems and Carbon Capture and Storage: Mapping possible interactions, technical considerations, and existing provisions. Berlin: International Carbon Action Partnership. Pg 7.

Point source carbon capture

The California Legislature has already laid out significant guidance and direction to CARB with respect to point source carbon capture or CCS in the passage of SB 905. Duplication of those efforts is perhaps unnecessary in the current discussion of cap-and-trade reauthorization. However, direction could be given to CARB to establish criteria for captured and stored carbon regarding permanence, liability, monitoring, etc. pursuant but not limited to SB 905, which if met, would ensure that properly captured and stored carbon dioxide does not constitute an emission subject to a compliance obligation. At minimum, these criteria should include: (1) guardrails regarding permanent storage, monitoring, and verification; (2) how to account for a potential storage "reversal" and liability for reversals when a storage reservoir leaks; (3) how emissions from transportation of captured carbon dioxide and other support equipment should be accounted for in a compliance obligation; (4) how to account for emissions from any increased demand in electricity; (5) whether and how to reduce the direct allocation of allowances to facilities employing CCS; (6) what kind of new regulatory oversight is required; and (7) provisions to avoid double-counting of climate benefits.[41]

The current cap-and-trade program regulations are ambiguous as to whether captured CO_2 emissions constitute a compliance obligation. Clarifying that captured emissions that are stored pursuant to SB 905 do not create compliance obligations for the party whose emissions are captured would provide an incentive to capture those emissions. The appropriateness of that determination would depend on the robustness of the SB 905 regulations, including whether the SB 905 regulations manage the possible reversal of stored emissions. This liability could be assigned to the party storing CO_2 pursuant to SB 905 regulations; however, policymakers may need to consider alternative environmental safeguard mechanisms if a storage project goes bankrupt, such as an adjustment to cap-and-trade program allowance supplies (as is done for emissions leakage in the CAISO Energy Imbalance Market and was done to address the consequences of Ontario's departure from the linked cap-and-trade program).

Summary Recommendation: The robust implementation of SB 905 is a priority and is necessary to inform the interaction of CCS and CDR with the cap-and-trade program. CARB may also consider other policies that need to be updated to reflect final SB 905 rules, potentially including but not limited to the cap-and-trade regulation.

Carbon dioxide removal

Unlike with point source carbon capture, the California legislature has yet to give clear direction on rules and strategy regarding carbon dioxide removal, other than to recognize its necessity in meeting the 2045 net-zero goal and maintaining net negative emissions thereafter pursuant to AB 1279 (Muratsuchi, 2022). The net-zero and net-negative goals are importantly coupled with the 85% reduction below the 1990 baseline, which helps to ensure that CDR cannot "crowd out" the emission reductions that are also essential to mitigating climate change, assuming regulations account separately for reductions and removals. In order to meet the net-zero and net-negative goals, as well as the nature-based climate solutions targets required under AB 1757 (C. Garcia, 2022),[42] California must support increased investment in and ensure environmental integrity of both engineered carbon removal strategies like DAC and nature-based climate solutions such as enhancing natural carbon sinks.

[41] For a discussion regulatory options both within and separate from a carbon market see: https://icapcarbonaction.com/system/files/document/La%20Hoz%20Theuer%20%26%20Olarte%20%282023%29.%20ETSs%20and%20CCS_ICAP.pdf

[42] https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/Californias-NBS-Climate-Targets-2024.pdf

To the extent the Legislature decides to address carbon removal within the cap-and-trade program, there are numerous considerations. Fundamentally, the cap-and-trade program should treat removals separately from emission reductions. Removal strategies should be considered a separate category of compliance instruments, similar to how offsets are a separate category of compliance instruments from allowances. CDR removes carbon dioxide from the atmosphere, regardless of where it came from; it does not reduce the emissions coming directly from a specified source.[43] Establishing a class of CDR credits separate from allowances would clearly differentiate carbon management strategies and help ensure appropriate and separate accounting of reductions and removals, as well as to draw relevant distinctions between the durability of different carbon storage reservoirs.

Legislators could consider giving direction to CARB as to which general types (direct air capture, wetland restoration, enhanced mineralization, etc.) of CDR projects they want considered for inclusion in the cap-and-trade program or other regulatory approaches identified above, if any. Among other factors, this direction should consider market readiness, scalability, and the ability to accurately quantify net carbon removal outcomes using robust and well-tested methodologies, along with environmental and community safeguards such as ongoing monitoring, financial assurances, public engagement, and provisions for reversals. If the Legislature wants to integrate CDR crediting into the cap-and-trade program, it may also want to direct CARB to establish a removal credit usage limit, similar to how offset credits currently have a usage limit. Accounting for removal credits “under” the cap would avoid any unintentional inflation of the emissions cap. An example of this mechanism exists in Washington State’s cap-and-invest program. When offsets are turned in for compliance an equal number of allowances from under the cap are retired from the program. There is further discussion of this approach in Chapter 7 of this report, but generally CARB should take an approach to any removal-based credits that does not *increase* the overall number of compliance instruments in the program above the annual budget required to meet the 2045 emission reduction goal.

Summary Recommendation: The Legislature could consider giving guidance to CARB or other regulatory agencies to develop rules and financial mechanisms to support the development of carbon removal projects, which are estimated in the 2022 Scoping Plan to cost tens of billions of dollars per year. IEMAC members were divided as to whether

[43] There are different perspectives on which strategies should be considered “removals.” For instance, bioenergy with carbon capture and storage (BECCS) converts biomass to bioenergy and captures the associated CO2. Because biomass is a carbon sink, burning it can be a carbon neutral process, so capturing the associated emissions qualifies as CO2 removal. Others would consider this process avoided (or reduced) emissions because the biomass is doing the removal, and the CCS creates a durability enhancement in the carbon storage from short (fast carbon cycle for plant carbon) to long (geologic storage).

the initial phase of CDR deployment should include formal crediting in the cap-and-trade program. If the Legislature provides guidance to incorporate CDR crediting into the cap-and-trade program, it should direct CARB to count removal of emissions separately from emission reductions and ensure that the inclusion of removal credits does not increase the overall number of compliance instruments in the program.

Conclusion

Numerous carbon management strategies will be necessary for California to achieve its 2045 climate goals, as well as its nature-based climate solution goals. Both the Scoping Plan developed by CARB and California's Nature-Based Climate Solutions established by CNRA assume a wide array of carbon reduction and/or removal strategies. But until the SB 905 regulations are complete, it is difficult to assess an appropriate or preferred role of CCS or CDR within the cap-and-trade program.

This brief summary is intended to build upon the 2023 IEMAC report chapter on CCS and subsurface carbon storage, and to provide options for lawmakers interested in carbon management as they consider reauthorization of the cap-and-trade program, as well as potential uses for the Greenhouse Gas Reduction Fund. Lawmakers have an opportunity, if they desire, to provide high-level direction to CARB and CNRA regarding the development of a carbon removal strategy, as well as the separate accounting of greenhouse gas removals and reductions.

Chapter 7. Carbon offsets

Danny Cullenward and Dallas Burtraw

California has a large carbon offsets program. As the end of December 2024, the California Air Resources Board (CARB) has issued more than 267 million offset credits across four protocols that credit activities involving forests across the continental United States and parts of Alaska (81%), the destruction of ozone-depleting substances (10%), coal and trona mine methane capture (6%), and livestock manure digesters (3%).[44] Of the 267 million credits issued, almost 35 million were set aside in the forest protocol buffer pool, leaving almost 233 million available for compliance use. As of the end of the fourth compliance period, compliance entities in the Western Climate Initiative surrendered about 209 million California-issued offsets for compliance purposes (and another 1.4 million offsets issued by the Government of Québec). The expanded number of compliance instruments resulting from offset availability has enabled growth of the allowance bank that totals approximately 379 million allowances.[45]

Under the original provisions of Assembly Bill 32 (Stat. 2006, Chap. 488), the offsets program is subject to several statutory requirements. Carbon offsets must be "real, permanent, quantifiable, verifiable, and enforceable" by CARB;[46] and the outcomes CARB credits must also be "in addition to" any outcomes "required by law or regulation" or "that would otherwise occur," which is collectively known as an additionality requirement.[47] CARB's cap-and trade regulations define the word "permanent" to mean at least 100 years; define "additional" as outcomes that "exceed any greenhouse gas reductions or removals that would otherwise occur in a conservative, business-as-usual scenario"; and define "conservative" to mean using assumptions and methodologies "that are more likely than not to underestimate" credited climate benefits.[48]

AB 32 authorized the original cap-and-trade program but did not specify or prohibit any role for carbon offsets. When CARB developed the original cap-and-trade program, it decided to include a carbon offsets program that expands the supply of compliance instruments in the cap-and-trade program. By regulation CARB limited the use of offsets

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44 CARB also approved two additional protocols that have not been used and allows California compliance entities to use offsets issued by its counterpart agency in Québec, which has issued an additional 1.7 million offset credits.

45 CARB, Q4 2024 Compliance Instrument Report. The number of offsets used for compliance purposes is taken from the "Retirement" account (column J), while the bank of allowances is calculated by adding the number of allowances held in private entities' "General" and "Compliance" accounts (columns B and C) for vintages 2013 through 2023 (rows 13 through 23).

46 Health and Safety Code § 38562(d)(1).

47 Health and Safety Code § 38562(d)(2).

48 California Code of Regulations, Title 17, § 95802 (see "permanent" "additional" and "conservative").

to no more than 8% of a covered entity's compliance obligations. While this limit might seem small numerically, it is similar in size to the reductions CARB initially anticipated from the cap-and-trade program through 2020.[49] Offsets can be banked indefinitely without limits on the total number of offsets an entity can hold at any given time; however, eligibility to use offsets for compliance cannot be transferred or banked.

When the legislature re-authorized the cap-and-trade program in Assembly Bill 398 (Stat. 2017, Chap. 135), it enacted new limits on the use of carbon offsets. AB 398 lowered the limit from 8% to 4% for emissions in calendar years 2021 through 2025, rising back up to 6% in calendar years 2026 through 2030. AB 398 also required that covered entities use no more than half of the 4% or 6% limit from projects that do not deliver "direct environmental benefits" to state air or water quality.[50] There are no regulatory or statutory limits on offset use after 2030.

Actual offset usage was reported as follows:[51]

Reporting period	Offsets as % of compliance	Offsets limit
2013-2014	4.39%	8%
2015-2017	6.36%	8%
2018-2020	6.94%	8%
2021-2023	3.10%	4%

Offset issuance and price data are as follows:[52]

49 See this explanation from UC Berkeley researcher Dr. Barbara Haya.

50 Health and Safety Code § 38562(c)(2)(E).

51 Data sources: 2013-2020 (IEMAC 2021: 30) and 2021-2023 (CARB's compliance report).

52 Issuance is based on CARB's ARBOC issuance table and prices are weighted average prices for U.S. forest ARBOCs and allowances from CARB's annual summary of market transfers report. Issuance data are reported net of buffer pool contributions.

		Price (nominal USD per credit)			Value of issuance (million nominal USD)	
Year	**Issuance (millions)**	**Generic Credit**	**Forest DEB**	**Allowance**	**100% generic credits**	**50% generic, 50% DEB**
2013	3.92	—	—	—	—	—
2014	9.82	$9.65	—	$11.95	$94.8	—
2015	17.21	$10.20	—	$12.66	$175.5	—
2016	17.34	$10.86	—	$12.76	$188.3	—
2017	28.28	$11.89	—	$14.40	$336.2	—
2018	46.64	$13.16	—	$15.13	$613.8	—
2019	22.76	$14.13	—	$17.07	$321.6	—
2020	39.36	$13.71	—	$16.86	$539.6	—
2021	15.18	$14.91	$16.14	$25.39	$226.3	$235.7
2022	10.41	$17.74	$19.91	$28.50	$184.7	$196.0
2023	12.21	$20.88	$26.65	$33.97	$254.9	$290.2

Beyond their role as a compliance option for regulated emitters and associated effects on compliance costs, offsets also play an important role in directing resources to sectors and stakeholders that are not directly regulated in the cap-and-trade program. Some of the most important stakeholder groups that benefit from the current program are Tribes and Alaskan Native communities. Of the more than 267 million offset credits issued by CARB through 2024, we estimate that about 61 million were issued to projects involving Tribes and Alaskan Native communities across the United States. The income from selling these credits to covered emitters can be significant in both financial and nonfinancial terms. For example, the Yurok Tribe, which is the largest federally recognized tribe in California, has earned more than 3 million credits, the sale of which helped the Yurok Tribe purchase tracts of ancestral land.

Policy design purposes

Carbon offsets have three primary effects:

- **Offsets that expand the supply of compliance instruments reduce carbon prices.** Carbon offsets currently expand the supply of compliance instruments because they are issued in excess of the program's allowance budgets. Because carbon offset prices have historically been below the auction price of allowances, offset availability lowers the compliance cost for regulated entities. Further, offsets substitute for the most expensive (marginal) mitigation options that determine the market price of allowances, so increasing the market-wide supply of compliance instruments reduces the resulting carbon price, which also lowers compliance costs for covered emitters and reduces revenues collected for the Greenhouse Gas Reduction Fund and California Climate Credits. For example, a recent issue brief from Resources for the Future (Burtraw and Roy 2025) estimates that limiting the eligibility to use offsets to 4% in 2026 would increase the allowance price in that year by $1.28 (2023$).
- **Offsets direct resources to target sectors and stakeholders.** The sale of carbon credits raises funds that support project activities in the sectors and geographies where projects are eligible to earn carbon credits. These sectors are not covered by the emissions cap and often involve activities that are not subject to direct climate regulations, such as activities involving carbon storage in natural and working lands. A significant fraction of the activities credited in these sectors involve Tribes and Alaskan Native communities. While reporting data do not indicate how much of that total value is transferred to project intermediaries, such as credit brokers and project developers, covered entities transfer significant funds to target sectors and participating stakeholders when they purchase offset credits. These are private transfers from greenhouse gas emitters directly to offsets projects, bypassing rather than involving the state's Greenhouse Gas Reduction Fund.
- **Offsets shift where emissions and reductions occur.** Offsets allow for higher emissions from fossil fuel use at regulated sources covered by the cap-and-trade program in exchange for lower emissions or greater carbon storage outside the cap-and-trade program. This can lead to environmental justice harms inside the state (discussed further in Chapter 5) as well as corresponding environmental and equity benefits in project locations, including on Tribal lands. The IEMAC has previously observed that offsets can make it harder to achieve statewide greenhouse gas

emissions limits, as they allow higher emissions from covered entities in exchange for climate benefits claimed outside of the cap-and-trade program (IEMAC 2021: 27-35). Because many projects are outside the state and most projects inside the state are not included in the state's AB 32 greenhouse gas inventory, offsets have the practical effect of increasing statewide emissions as those emissions are recorded in the AB 32 inventory. (In-state projects generate benefits that are recorded in a separate natural and working lands inventory, which CARB does not use to track compliance with state emission reduction laws.)

Evidence about the program's performance

A growing number of academic studies have questioned whether California's carbon offsets program is achieving its intended climate mitigation objectives (Haya et al. 2020), particularly when it comes to the forest carbon protocols that generate 81% of offset credits. Major concerns include:

- **Non-additionality.** Some studies compare carbon storage and timber harvest rates across forests that enrolled in the carbon offsets program and similarly situated lands that did not, finding that credited carbon outcomes have "generally not been additional to what might otherwise have occurred" (Coffield et al. 2022) and that the researchers' analysis "failed to demonstrate additionality" due to relatively similar disturbance rates between enrolled and control group forests (Stapp et al. 2023).

- **Project baselines.** Other studies critique the statistical methods by which CARB's forest offset protocols credit avoided timber harvests in projects' baseline scenarios, finding that "nearly a third" of offset credits analyzed "do not reflect real climate benefits and are, instead, the consequence of methodological shortcomings" (Badgley et al. 2022a) and that several projects "did not preserve or increase carbon stocks above what was typical, suggesting that no carbon offsets should have been issued" (Randazzo et al. 2023).

- **Non-permanence.** CARB defined the statutory requirement to credit "permanent" outcomes as being satisfied if carbon dioxide is stored outside the atmosphere for at least 100 years and developed a "buffer pool" insurance program to cover forest carbon lost to wildfires, drought, disease, and other impacts over this timeline. There are two related concerns. First is that 100 years is not truly "permanent" or comparable to the atmospheric lifetime of fossil fuel emissions, which lasts for tens of thousands of years (Archer et al. 2009, Badgley et al. 2022b, Joos et al. 2013). Second is that the risk of reversal on a 100-year timeframe is underestimated. Several studies have criticized the buffer pool for assuming that these risks are constant across the United States and will not get worse with climate change (Anderegg et al. 2020); for being too small, as the number of offsets set aside to compensate for wildfire-related losses was consumed in less than 10 years (Badgley et al. 2022b) and total wildfire losses through 2024 are projected to consume 39% of the total buffer pool (Badgley 2024); and for failing to account for growing climate-related forest carbon storage reversal risks (Wu et al. 2023). Offset reversals are ultimately backed by liability of the project owner, providing some additional assurance that the issued credits, if invalidated, will be replaced with additional offsets or compliance instruments. However, courts have found that entities' obligations under the cap-and-trade regulation are dischargeable under bankruptcy.[53]

- **Leakage.** CARB's protocol assumes that avoiding timber harvests in project lands leads to only 20% of that activity to be displaced and "leak" to other timber-producing areas, but the academic literature suggests that substantially higher leakage rates may occur in practice (Haya et al. 2023). CARB's forest offset protocol also provides substantial upfront crediting for avoiding timber harvests over 100 years (Badgley et al. 2022a) but does not deduct leakage emissions in a synchronous and consistent manner (Haya et al. 2023).

CARB's October 2024 market notice indicates that CARB is considering changes to the mine methane and ozone depleting substances protocols. CARB is not planning to consider any changes to the forest offsets program in its upcoming rulemaking process, though CARB has indicated that it intends to revisit the protocol's buffer pool design for non-permanence after completion of a study with the U.S. Forest Service.

The IEMAC also observes that the offsets program has been the subject of litigation.[54] In 2012, a group of plaintiffs challenged CARB's approach to determining additionality in the offsets program. Then, as now, CARB used both financial analysis and a "standardized" approach to assess additionality at the level of entire offset protocols (rather than for every individual offset project credited under a given protocol).[55] The Court of Appeals of California rejected the plaintiffs' challenge and upheld CARB's approach in 2015.[56] While this decision confirms CARB's authority to use financial analysis and/or a "standardized" approach to determine additionality in the offsets program, its broader legal meaning is nuanced. Because the case involved a facial

53 California Air Resources Board v. La Paloma Generating Company LLC, Case No. 1:17-CV-1698 (D. Del., July 31, 2018).

54 *Our Children's Earth Foundation v. State Air Resources Board* (2015) 234 Cal.App.4th 870.

55 *Id*. at 882-883.

56 *Id.* at 887-892. The California Supreme Court declined to hear any further appeal. *Id*. at 893.

challenge to the type of approach CARB adopted, rather than an “as applied” challenge, it does not speak to or resolve questions about the program’s performance in practice.

Alternative policy options and considerations

Policymakers may wish to consider two alternative approaches to carbon offsets:

- **Use offsets in place of allowances.** One reform would be to reduce allowance supplies based on the number of offset credits issued, which would hold the number of compliance instruments constant. This approach was adopted by Washington state in its cap-and-trade program. If adopted in California, it would have two effects. An offset credit would be used by a firm for compliance if it cost less than an allowance (which would lower compliance costs); however, the reduction in total compliance instruments would also raise the market-wide allowance price (which would increase compliance costs and Greenhouse Gas Reduction Fund revenues). An advantage of this approach is that it would help address concerns that offset credits do not reflect real, additional, or permanent climate benefits by reducing allowance supplies in parallel to credit issuance. To the extent that offsets do not achieve their stated goals, then the reduction in allowance supplies can help ensure that the overall effect is to reduce net greenhouse gas emissions. This approach would also continue to channel investments to sectors not regulated directly under the cap-and-trade program. On the other hand, this approach would decrease allowance supplies. This would increase the cost of compliance across the program and therefore increase allowance prices. It would also result in a smaller increase in Greenhouse Gas Reduction Fund revenues relative to replacing offsets with a procurement fund because both reforms would increase allowance prices by a similar amount, but the procurement fund would not reduce allowance supplies. Similarly, using offsets to replace allowances could potentially produce fewer climate benefits than a procurement fund model, though only if an alternative procurement program supports climate mitigation outcomes that are more effective than current offset practices.

- **Replace offsets with projects or credits procured with dedicated cap-and-trade funding.** Policymakers could phase out all or some portion of the current offsets program and replace it with dedicated funding from the Greenhouse Gas Reduction Fund. Potential advantages of this approach include increased revenues for the Greenhouse Gas Reduction Fund, the ability to select target sectors and support state policies like the Natural and Working Lands strategy (rather than let the market choose project outcomes), and the ability to choose projects and programs based on any mix of climate, biodiversity, equity, and geographic preferences policymakers like, including Tribal priorities (rather than letting the market choose project outcomes). Potential disadvantages of this approach include uncertainty about the availability of future Greenhouse Gas Reduction Fund revenues, competition with other priorities for limited program revenues (including environmental justice priorities), challenges related to sunsetting the existing offsets program (such as how existing projects, credit owners, and compliance emitters would be affected during a transition), and the increase in allowance prices that would be expected to follow from a reduction in compliance instrument supplies (which should be similar to the increase in prices expected from using offsets to replace allowances).

If policymakers wish to retain a carbon offsets program, they might consider three additional matters:

- **Change offset compliance use limits.** The original 8% limit on offset use through 2020 was set by regulation. AB 398 specified lower limits of 4% from 2021 through 2025 and 6% from 2026 through 2030, with no more than half of total offsets coming from projects that do not deliver direct environmental benefits to state air or water quality. No limits have yet been set by the Legislature or CARB for post-2030 offset use. The legislature could revise existing limits and/or set different limits after 2030. While the IEMAC agreed that it would be useful for the legislature to provide statutory instruction on the post-2030 use of offsets, if any, committee members were divided as to whether the legislature should consider changes to the existing limits through 2030. One advantage of considering changes to the current limits is that changes could help establish the viability of alternative funding models. For example, the legislature could keep the 4% limit in effect through 2025 in place through 2030, which would reduce the eligibility of offset use beginning in 2026. This change would be expected to produce higher costs of compliance and higher allowance prices relative to the status quo. It would also yield greater Greenhouse Gas Reduction Fund revenues, which could be directed to investments in natural and working lands (or other applications) to replace the funding that would have otherwise been channeled through the higher 6% limit on offsets. On the other hand, changing offset limits previously set by statute could disrupt current market expectations and unfairly prejudice market actors, such as offset project developers including Tribes, who made decisions based on the provisions of the previous extension bill. The committee observes that because AB 398 did not address the post-2030 operation of the cap-and-trade program, it would not be reasonable to assert reliance on the continuity or reform of current program design features after 2030.
- **Establish a tribal-specific offset compliance option.** Washington state’s cap-and-trade program provides an example that could inform California’s approach to offsets. Washington allows compliance entities to surrender offsets equal to up to 8% of their compliance obligations but provides that no more than 5% can come from projects not involving federally recognized tribes while allowing for an additional

3% from projects that do involve federally recognized tribes.[57] This is similar to California's approach to direct environmental benefits to state air or water quality under AB 398. For example, from 2026 through 2030, compliance entities in California can surrender offsets equal to up to 6% of their compliance obligations, with up to 3% from projects that do not generate direct environmental benefits and an additional 3% from projects that do deliver environmental benefits. The IEMAC notes that if this approach were adapted to provide a tribal-specific offset compliance option in California, it would prioritize the participation of tribal parties in the offsets program but would not address any concerns related to the effectiveness of offset projects.

- **Implement regular and consistent updates to offset protocols.** Several studies cited above have raised concerns about additionality, baseline, and over-crediting of offset credits, especially in the forestry offset program. Unfortunately, the forestry protocol adopted by CARB has not been updated since 2015 to reflect research findings and recommended improvements to crediting methodology. Researchers who identify shortcomings in the current protocols also recommend regular methodological updates to respond to critical findings (Anderson-Teixeira & Belair 2022). The legislature could direct CARB to immediately update the offset protocols, specifically the Improved Forest Management protocol, and could further direct the agency to update protocols on a prescribed regular basis (i.e., every 3 or 5 years). While this would not alleviate environmental justice concerns about the displacement of direct emission reductions, it could increase other climate, social, and biodiversity benefits of the program relative to the status quo.

Whether policymakers retain the current system or consider structural reforms, it would be important to address several considerations:

- **Cost containment.** The availability of carbon offsets leads to lower allowance market prices. If the use of offsets reduced the supply of allowances or were replaced with a procurement-based alternative funded by the Greenhouse Gas Reduction Fund, then offsets would stop contributing to lower market prices.

- **Effect on the Greenhouse Gas Reduction Fund.** Reducing offset availability or reducing the supply of allowances as a condition of offset use would reduce the number of compliance instruments and increase the allowance price. An issue brief from Resources for the Future (Burtraw and Roy 2025) estimates that limiting offset supply to 4% beginning in 2031 compared to the anticipated 6% would increase the allowance price by just under one dollar. Because the market responds to cumulative allowance supply a price effect would be felt immediately, and this reform

[57] The IEMAC notes that many tribal communities in California are not federally recognized.

would increase cumulative GGRF revenues by $225 million (2024$) over the five-year period (2026-2030).

- **Effect on statewide emissions.** Because offsets allow for higher emissions in the AB 32 statewide greenhouse gas inventory in exchange for emission reductions that are not currently included in the AB 32 inventory (such as forests) or that manifest outside the state, their use results in higher emissions in the AB 32 inventory. While this accounting convention does not recognize climate benefits that can be achieved in other sectors or outside of California, statutory emission limits for 2020, 2030, and 2045 are defined in terms of "statewide" emissions and CARB has consistently used the AB 32 inventory as the basis for compliance with these requirements.

- **Tribal considerations.** Many of the projects supported by California's existing forest carbon offset program are operated or owned by Tribes. If the offsets program were replaced with dedicated cap-and-trade funding, it would be important to ensure that there is a transition plan that addresses the commitments made to existing parties, including Tribal parties. Policymakers may wish to consider whether additional program design considerations could support Tribal cooperation in an expenditure-based program, such as requirements to direct a minimum percentage of funds to projects or programs involving Tribal partners to ensure that the overall level of financial investment in Tribal activities is maintained or increased relative to the status quo. (The IEMAC has not consulted with any Tribes and does not purport to speak on their behalf.)

- **Environmental justice considerations.** Policymakers may also wish to consider how the presence or absence of carbon offsets affects the distribution of pollution and environmental co-benefits. Because offsets do not reduce emissions directly from sources, they may be contributing to higher environmental harms than would be the case in the absence of carbon offsets, particularly in communities that are already over-burdened with air pollution. At the same time, carbon offset projects can create environmental co-benefits in the places where they are located. Eliminating or phasing out offsets would affect both the harms and benefits associated with the use of offsets today.

- **Market disruptions.** If policymakers decide to replace or significantly reduce offset use, they may wish to consider how to implement their preferred direction in a manner that minimizes potential disruptions to the offset market going forward. For example, market actors might have made investments or other commitments on the basis of the statutory eligibility criteria in AB 398 that extend through 2030. Making changes to program operations before 2030 would be more disruptive than making changes to post-2030 program operations, which have not yet been established. An incremental approach that revisited the anticipated step-up in offset eligibility from

4% to 6% in 2026 could provide an opportunity to develop new procedures to ensure continued investments in natural working lands while leaving intact the existing program and leave unaffected existing contracts, but such an approach could impact program stakeholders who made decisions on the basis of the existing statutory limits.

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