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Allowance Allocation in a CO_2 Emissions Cap-and-Trade Program for the Electricity Sector in California

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RESOURCES FOR THE FUTURE

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Abstract

The regulation of greenhouse gas emissions from the electricity sector within a cap-and-trade system poses significant policy questions about how to allocate tradable emission allowances. Allocation conveys tremendous value and can have efficiency consequences. This research uses simulation modeling for the electricity sector to examine different approaches to allocation under a cap-and-trade program in California. The decision affects prices and other aspects of the electricity sector, as well as implications for the overall cost of climate policy. An important issue is the opportunity for emission reductions in California to be offset by emission increases in neighboring regions that supply electricity to the state. The amount of emission leakage (i.e. an increase in CO_2 emissions outside of California as a result of the program) varies with the regulatory design of the program.

Key Words: cap-and-trade, electricity generation, electricity sector, emissions, regulation, governance, allocation, California

JEL Classification Numbers: Q2, Q25, Q4, L94

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Allowance Allocation in a CO_2 Emissions Cap-and-Trade Program for the Electricity Sector in California

Karen Palmer, Dallas Burtraw, and Anthony Paul *

Executive Summary

In 2006, California adopted the California Global Warming Solutions Act (Assembly Bill 32), which requires the state to reduce aggregate greenhouse gas (GHG) emissions to 1990 levels by 2020. In December 2008, the California Air Resources Board released a proposed framework for its plan that outlines important roles for a collection of regulations, voluntary measures, and other policies to reduce carbon dioxide (CO_2) emissions. The plan also proposes a role for cap and trade, which refers to the introduction of a limit (cap) on aggregate GHG emissions, coupled with the opportunity for emitters to buy, sell, or bank the opportunity to emit up to the level of the cap. The details of the cap-and-trade program and exactly how it will relate to the other measures and policies is a decision that will be made in the next couple of years.

In California, a cap and trade program implemented economywide would be likely to cover roughly 83 percent of emissions. Other applications of cap and trade for CO_2 have covered only some sectors. For example, only the electricity sector is covered in the case of the northeast Regional Greenhouse Gas Initiative (RGGI), which launched a cap-and-trade program in January 2009 that affects 10 states. This research addresses the options for regulation of California's electricity sector *within* the context of an economywide cap-and-trade program in the state, and potentially the western region or the nation. A simulation model of the national electricity markets is used to look at how different approaches to allocating CO_2 allowances within the electricity sector affect the performance of the regional electricity markets and of the cap-and-trade program.

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One issue the study examines is emissions leakage (i.e., an increase in emissions from sources outside of California that offset some of the reductions from sources in the state). One approach to account for emissions associated with generation out-of-state is called the “first deliverer approach,” which imposes an obligation to comply within the cap-and-trade program upon the financial entity that brings power into the California electricity grid. The research also considers how expanding the geographic scope of a cap-and-trade program in the region to address leakage affects the cost of controlling CO_2 emissions and the impact of a cap-and-trade program on electricity consumers both in California and beyond. In addition, the paper addresses the crucial question of the initial distribution, or allocation, of emissions allowances. Two approaches are considered: an auction (we do not address how revenues from an auction might be spent), and free allocation to local distribution companies, which are the companies that provide retail services to customers. The latter approach is termed “load-based allocation.”

The most important findings of this study are listed below:

- An allowance auction coupled with regulations that cover emissions from out of state that are imposed of the first deliverer of power into the state could cap CO_2 emissions from electricity consumption in California at 30 percent below business-as-usual levels in 2020 with roughly an 11 percent increase in electricity price in California.
- About half of that price increase would be mitigated if allowances are allocated to local distribution companies (i.e., investor-owned and municipal utilities involved in the delivery of electricity to consumers within a specific geographic area) in California on the basis of population (load-based allocation). The lower electricity price effect with load-based allocation comes at a cost. This allocation approach would yield a CO_2 allowance price in 2020 that is more than 100 percent higher than the allowance price resulting under an auction. With a smaller increase in electricity price, electricity consumers would have a weaker incentive to conserve electricity, which means that there will be more demand for the fixed quantity of emission allowances, thus driving up their price.
- Under an economywide CO_2 cap-and-trade program with load-based allocation in the electricity sector, the higher allowance price effect that results compared to an auction has implications for other parts of the California economy. The relatively lower electricity price and associated higher electricity demand imply that fewer emission reductions would be achieved within the electricity sector than would occur with an allowance auction, and consistent with the higher overall allowance price, more would be required from other sectors of the California economy.

- With an allowance auction, roughly one-quarter of the emission reductions targeted for 2020 in a CO_2 cap-and-trade policy in the California electricity market would be lost through emissions leakage. Under a load-based approach to allocation, the percentage of emissions reductions lost through emissions leakage would rise to 45 percent. If the state were to ignore emissions associated with imported power (an approach that would not comply with AB32), emissions leakage would approach 100 percent.
- Imposing a western regional CO_2 emissions cap on the electricity sector that delivers similarly ambitious percentage reductions in emissions throughout the region as modeled in the California-only policy would address the emissions leakage problem. It would do so at lower cost to California electricity consumers and at a substantially lower marginal cost of CO_2 emissions reduction than a cap-and-trade policy limited to California. Allocating allowances to local distribution companies in the broader western region will reduce the size of the increase in electricity price, but will increase allowance price by nearly 30 percent compared to an auction.

In summary, this analysis suggests that the most cost-effective approach to implementing a cap-and-trade program in the electricity sector would be to use a first deliverer for the point of compliance and to use an auction for the allocation of emission allowances. The effectiveness of the program will be greatly enhanced if it involves states throughout the western region. Finally, we note that California’s decision about the architecture of AB 32 could play an important role in helping to shape climate policy in other states and regions, and at the federal level.

1. Introduction

In 2006, California adopted the California Global Warming Solutions Act (Assembly Bill 32), which requires the state to reduce aggregate greenhouse gas emissions to 1990 levels by 2020. The act charges the California Air Resources Board (ARB) to develop a comprehensive plan for implementation by January 1, 2009. In December 2008, the ARB proposed a framework for its plan that outlines important roles for both a cap-and-trade approach and a collection of regulations, voluntary measures and other policies to reduce CO_2 emissions. The details of the cap-and-trade program and exactly how it will relate to the other measures and policies is a decision that will be made in the next couple of years.

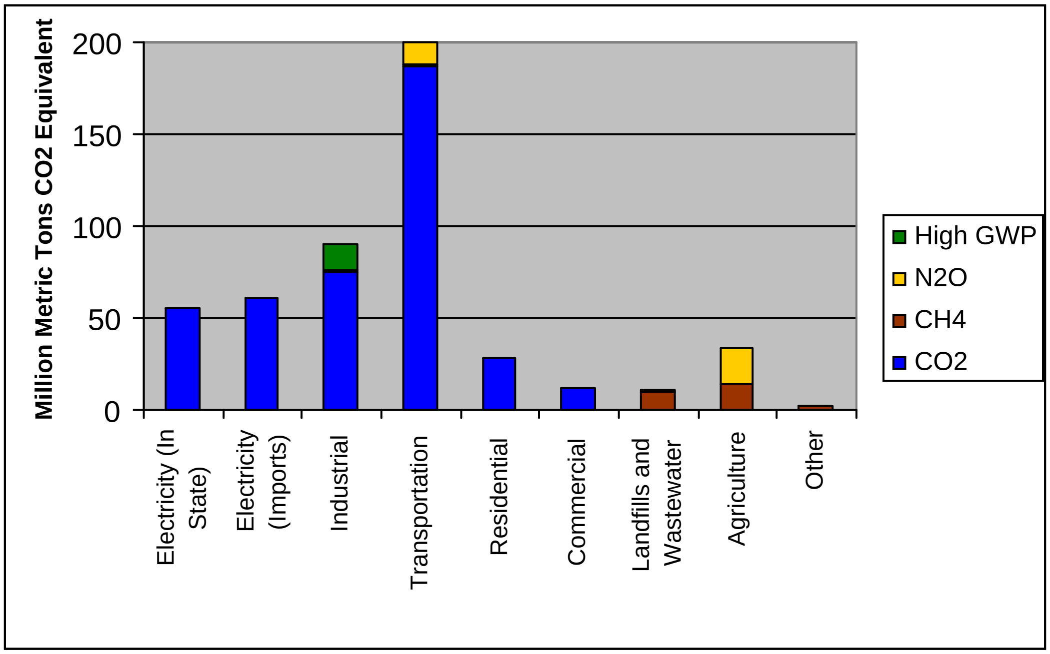
One of the challenges California faces is how to regulate the electricity sector. Electricity consumption (including emissions associated with imported power) is estimated to account for 23.5 percent of the greenhouse gases in the state, including about 27.7 percent of the carbon dioxide (CO_2) emissions (California Market Advisory Committee 2007). This is a low percentage compared with the rest of the country, where electricity consumption accounts for about 33 percent of greenhouse gases and about 40 percent of CO_2 emissions.[1] The largest category of greenhouse gas emissions in California is transportation, which accounts for about 40.4 percent. Nonetheless, the electricity sector remains very important to the design of the California trading program.

First, the electricity sector is typically identified as the source of most potential greenhouse gas reductions in the near term, at least at the national level, where modeling indicates that the electricity sector will account for between two-thirds and three-quarters of emissions reductions in the next two decades under national policy (U.S.EIA 2007b; Pizer et al. 2006). In California, however, there may be fewer low-cost opportunities for emission reductions in the electricity sector because little electricity is generated using coal, limiting the potential emissions reductions from fuel switching away from coal. Second, experience with cap-and-trade programs elsewhere has been largely in the electricity sector. Previous programs, including

[1] U.S. electricity emissions are about 9 percent of total CO2 emissions worldwide. The Market Advisory Committee (2007, p. 41) reports that the carbon intensity of electricity generation in California in 2004 was 700 pounds of CO2 per MWh. Accounting for imported power brings the average emissions intensity of electricity consumed in the state to 930 pounds per MWh. Across the nation, the average emission intensity of electricity generation is 1,176 pounds per MWh.

the sulfur dioxide (SO_2) and nitrogen oxide (NO_x) trading programs in the United States have focused primarily on electricity generators and the Emission Trading Scheme for CO_2 in the European Union focuses exclusively on point sources, the majority of which are also electricity generators. The electricity sector has been successful as a testing ground for this type of regulation.

Figure 1. California Emissions of Greenhouse Gases, 2004



Source: California Market Advisory Committee 2007.

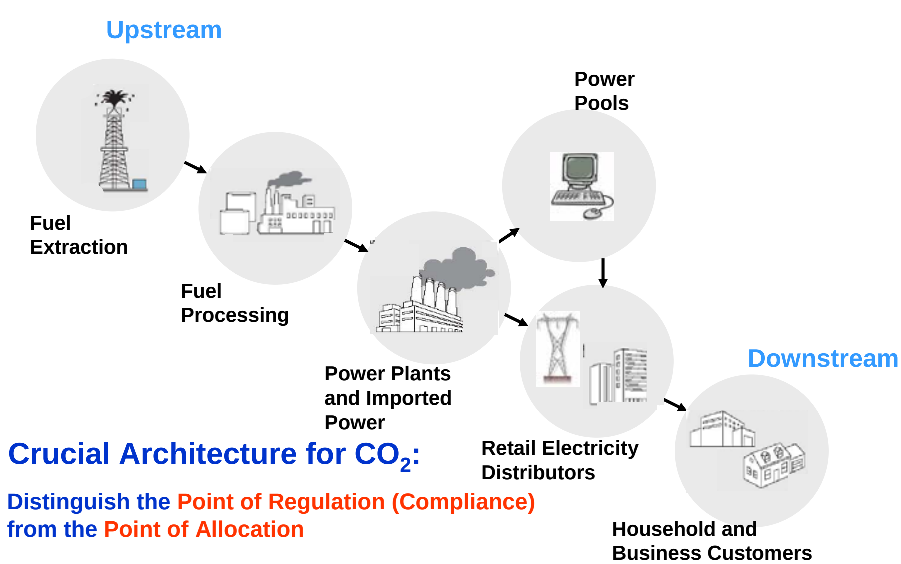
California's own generation resources are low emitting, while its imported power is relatively high emitting. About 80 percent of the electricity consumed in the state is generated in the state, but as illustrated in Figure 1, about 52 percent of the greenhouse gas emissions associated with electricity consumption comes from outside the state (CEC 2006).[2] Attempts to regulate only in-state sources would be expensive per ton of emissions reduction compared with the opportunities to reduce emissions on a broader scale. Given the open transmission system, attempts to regulate only in-state sources also would lead to more imported power, with an

[2] This measure is somewhat ambiguous because it is based on financial contracts with out-of-state generators. To some degree, if those facilities did not serve California, they would serve other customers in the west.

associated increase in out-of-state emissions. The act anticipated this issue by requiring that the state's greenhouse gas reduction target include the out-of-state emissions associated with California electricity consumption.

This research addresses options for the regulation of California's electricity sector within the context of an economywide cap-and-trade program in the state, and potentially for the nation. A simulation model of the national electricity markets is used to look at how different approaches to allocating CO_2 allowances[3] within the electricity sector affect the performance of the regional electricity markets and of the cap-and-trade program. The main options for allocation that are addressed include an auction and free allocation to local distribution companies (LDCs) that are responsible for the distribution of power to retail customers.[4] For most customers the LDC and the load serving entity (LSE) are one in the same, but they need not be if a customer is purchasing electricity from an entity other than its local utility in which case that other entity is the LSE and the LDC is still the one that ships electricity to your door.

Figure 2. Potential Points of Compliance in the Electricity Sector



[3] An allowance is an intangible property right that enables the emissions of one unit of a regulated air pollutant. A regulated entity must surrender allowances to cover all of its emissions during a compliance period.

[4] Other options for allocation that are available include free allocation to generators or to first deliverers on the basis of historic sales (known as historic allocation or on the basis of sales in a more recent year with the basis of allocation being updated over time (known as updating allocation).

As Figure 2 illustrates, the point of allocation and the point of compliance need not be the same. The term allocation implies free initial distribution of emission allowances, but in fact there may be no free allocation at all. A substantial literature has advocated for the use of an auction rather than free allocation for distributing allowances.[5] This is the approach being used for nearly 90 percent of the allowances being distributed by the 10-state northeast Regional Greenhouse Gas Initiative that took effect in January 2009.[6] An auction approach also was the approach highlighted as preferable, perhaps after a transition period, by the California Market Advisory Committee. Discussions of allowance allocation in California also have included the possibility of allocating allowances for free to local distribution companies, which would transfer a substantial amount of the allowance value created by the program to electricity consumers.

In this study, the modeling analysis of a California-only cap-and-trade program for CO_2 applied to first-deliverers in the California electricity market suggests that such a program would result in leakage (i.e., an increase in CO_2 emissions outside of California in response to the program) of 26 percent of the emissions reductions achieved under the program if allowances were distributed through an auction, and 45 percent if allowances were allocated for free to local distribution companies. Compared to an auction, allocating allowances to local distribution companies on the basis of population in the service territory would reduce the effect of a cap-and-trade policy on average electricity price in California by roughly half. However, the smaller price effect would come at a cost of a 100 percent increase in allowance prices in 2020. In an economywide program, this would translate into the need to achieve greater reductions outside the electricity sector, at higher cost.

Expanding the geographic scope of the program to encompass all the western states substantially addresses the leakage concern and lowers both the marginal cost of CO_2 emission reductions, as reflected in the allowance price, and the effect of the policy on electricity price in California. Allocating allowances to local distribution companies in the broader western region

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[5] See, for example, Parry (1997) and Goulder et al. (1999), who demonstrate that an auction with revenue recycling aimed at the reduction of other taxes dramatically lowers the social cost of the policy. Burtraw et al. (2001) demonstrate that an auction also has the property of providing more efficient pricing in regulated regions of the country. Ruth et al. (2008) demonstrate that an auction can provide revenues that reinforce program goals by funding investments in energy efficiency and thereby lower the cost of the program for consumers.

[6] The Initiative's Memorandum of Understanding specified that all states should allocate at least 25 percent of the emissions allowances created by a cap-and-trade program to consumer benefit and strategic energy initiatives. An auction of allowances is the most likely way to implement this policy.

will reduce the size of the increase in electricity price, but will increase allowance price by nearly 30 percent compared to an auction.

The next section provides background for regulation of CO_2 in the California electricity sector. Section 3 introduces the modeling scenarios and Section 4 presents analysis. Section 5 provides concluding observations.

2. Regulating CO_2 in California's Electricity Sector

One month after the passage of the California Global Warming Solutions Act, Governor Schwarzenegger issued an executive order creating the Market Advisory Committee to advise the California Air Resources Board (ARB) on developing a plan for a cap-and-trade program. One alternative identified by the committee was an upstream approach that would regulate emissions at the point where fossil fuels enter the economy. Implementation at this point could achieve coverage of 83 percent of the greenhouse gas emissions in the state by regulating 150 facilities, plus regulation of entities that bring electric power into the state.[7]

However, the approach that received the most attention, partly based on precedent in other trading programs, was midstream regulation. As illustrated by Figure 2, this approach would regulate midway in the fuel cycle between the introduction of fossil fuels into the economy and their end use. This approach could achieve a comparable coverage of 83 percent of the state's emissions by regulating 490 facilities, assuming that transportation fuels would be regulated at the refinery.

An important question that has been addressed by the CPUC and CEC is how the regulation would be implemented in the electricity sector. In the winter of 2008, these agencies recommended that ARB should pursue the *first-deliverer approach*, originally proposed as the so-called *first-seller approach* by the Market Advisory Committee (2007). It would place a legal obligation for reporting and compliance on the first deliverer of power, which is the owner, operator, or power marketer for a generation facility located in the state, or the party bringing power onto the electricity grid for power generated out of state. Compliance would be required for power placed into the transmission system from that facility. For in-state sources, a first-deliverer approach would look the same as the source-based system that characterizes previous

[7] This approach would require monitoring and reporting for all fossil fuels produced in or imported into California, as well as fuel exports. This includes about 100 business entities that take delivery of gas via a pipeline.

trading programs, such as the SO_2 trading program, in which compliance is required at the point of combustion—that is, where emissions are released into the atmosphere.

The first deliverer approach is an imperfect tool for dealing with imported power. It is worth emphasizing that if California's program is integrated into the efforts of the seven states and three Canadian provinces participating in the Western Climate Initiative and if a cap-and-trade program is implemented in this broader geographic region, the issue of electricity imports will be much reduced.

Nonetheless, even with a first deliverer approach there is the possibility for contract shuffling, which is the opportunity for wholesalers of out-of-state power to shift the assignment of existing sources with relatively low emissions rates to serve California while assigning higher-emitting sources to serve other load centers outside California. According to Bushnell (2007) and Fowlie (2007), contract shuffling could result in no real change in the resource mix and therefore no real change in CO_2 emissions throughout the western electricity grid under AB32 even under nominal compliance with AB32 and "reductions" from baseline emissions levels.

There is reason to believe that the opportunities for contract shuffling may be more limited than identified by Bushnell and Fowlie. First, emissions trading would occur in a regulatory context that already has introduced significant regulations and initiatives aimed at reducing CO_2 emissions associated with electricity consumption. These include the CPUC's loading order rule adopted in May 2003 that establishes the priorities for energy procurement for IOUs. [8] The PUC's procurement rule and SB 1368 prohibit long-term contracts with facilities that do not meet a GHG emissions standard, which is set equal to an efficient natural gas combined cycle facility. In addition, they do not model the first deliverer approach. The approach would rely on the California Climate Action Registry's (CCAR) Power/Utility Reporting Protocol, which assigns emissions intensity to imported power. According to a recent study by the California Energy Commission (Alvarado and Griffin 2007), relying on the CCAR protocol allows for a precise identification of the power plant and associated emissions for about

[8] In December 2004, the CPUC adopted a CO2 cost adder of $8 to $25 per ton to be added into system dispatch, and in October 2005, it issued a policy statement on a greenhouse gas performance standard.

56 percent of imported power.[9] The remainder would have to be assigned an emission intensity based on other information, such as the average emission intensity for the control region from which the power is delivered into California based on information from the electronic North American Electric Reliability Council E-tag documents.[10] This is the information that regulators would use to make an assignment of out-of-state emissions to the use of electricity in California. This information would be used to assess the compliance responsibility of the party listed on the E-tag document—that is, the party that is the first deliverer of imported power to the electricity grid.

3. Simulation Analysis of CO_2 Emissions Cap and Trade for Electricity in California

The way in which emissions allowances are allocated and the geographic region that is regulated are expected to yield differences in allowance and electricity prices, new investments in California generators, and the mix of generation used to supply power in California. These decisions could also affect the amount of electricity imported into California and the mix of generation used in the remaining western states. In addition, policy design will affect the level of CO_2 emissions leakage into surrounding states. A simulation exercise is used to look at the effects of different approaches to a CO_2 cap-and-trade program for electricity in California on allowance markets and state and regional electricity markets.

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[9] Confidence in the estimate may be undermined by the evolution of contracting relationships over time. If a financial penalty is placed on high-emission import contracts, over time as contracts expire and are renewed, they will be replaced with new contracts with cleaner sources. This turnover of contracts could erode the effectiveness of the program because the new contracts do not necessarily imply there will be any different investment or operation of the electricity system than would occur in the absence of the program. Instead, the same generation capability could be assigned differently. On the other hand, California's regulatory efforts under AB 32 and the procurement rule precluding new long-term contracts with high-emitting facilities affect the investment climate in the power sector and raise the cost of capital for high-emitting projects, thereby affecting generation options over time, and these policies are expected to have a real effect on the nature of future investment. As California's efforts to facilitate an agreement with the multi-state Western Climate Initiative proceed, this effect should be more pronounced.

[10] E-tags are electronic documents used to track the transmission of electricity, so that sources of grid congestion can be more easily identified and mitigated. In addition to identifying the parties with financial ownership of the power, the E-tag identifies the source and destination control region. Parties identified on the E-tags are licensed to schedule power into the transmission grid.

3.1 Description of RFF's Haiku Model

The electricity supply and market analysis relies on a detailed simulation model of the electricity sector known as the Haiku Electricity Market Model (Haiku), which is maintained by Resources for the Future (Paul et al. 2009). Haiku is a deterministic, highly parameterized model that calculates information similar to the National Energy Modeling System used by the Energy Information Administration (U.S. EIA 2003)., and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (U.S. EPA 2006). As a deterministic model, Haiku does not include explicit treatment of uncertainty. It includes parameters representing costs, capacity, emissions characteristics and other features of electricity supply and demand. The data sources for the different categories of Haiku parameters are listed in Table 1. Figure 3 shows the inputs to and outputs from the Haiku model.

The Haiku model simulates equilibrium in regional electricity markets and interregional electricity trade. The model also identifies emission control technology choices for SO_2, NOx, and mercury at different types of generators. The composition of electricity supply is calculated using a fully integrated algorithm for capacity investment and retirement, coupled with system operation in temporally and geographically linked electricity markets. The model solves for electricity price levels and production levels that equate demand and supply in 21 Haiku market regions (HMRs) for the continental United States. Each of the 21 HMRs is classified by its electricity pricing regime as having either market-based electricity pricing (i.e., electricity prices determined by the cost of producing a kilowatt hour for the marginal generator) or regulated pricing (i.e. the average cost of supplying electricity for all generators supplying the market), as shown in Figure 4.

Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to market-based pricing of generation continue that practice, and those that have not made that move remain regulated. The price of electricity to consumers does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season[11]. Electricity demand is sensitive

[11] The structure of electricity prices in the future is the subject of a great deal of uncertainty. Research (Borenstein 2005) suggests that allowing prices to vary by time of day, even for a small subset of electricity consumers, could substantially lower the costs of supplying electricity, particularly during peak periods, by reducing demand for at least some customers. Ruth et al. (2008) find similar outcomes with respect to improvements in the efficiency in the end use of electricity. Even if these improvements occur in a subset of households and establishments, all customers benefit through a reduction in the retail electricity price.

to changes in electricity price and the nature of that responsiveness, or price-elasticity, varies by customer class and over time with less sensitivity in the short run and more sensitivity in the long-run as consumers have time to change their electricity using equipment in response to changes in electricity price. Simplified demand elasticities are used in this study, as reported in Table 2.

Table 1. Inputs to the Haiku Model and Data Sources

Variables	Source
Existing Generators	
Capacity	EIA
Heat Rate	EIA
Fixed and Variable O&M Cost	FERC\EIA\EPA
Existing Pollution Controls	EPA\EIA\RFF
Planned Pollution Controls	RFF
Baseline Emission Rates	EPA (CEMS/NEEDS)
Scheduled and Unscheduled Outage Rates	NERC GADS data
New Generators	
Capacity	EIA\EPA\Proprietary
Heat Rate	EIA\EPA\Proprietary
Fixed and Variable Operating Cost	EIA\EPA\Proprietary
Capital Cost	EIA\EPA\Proprietary
Outage Rates	EIA\EPA\Proprietary
Fuel Supply	
Wellhead Supply Curve for Natural Gas	Interpolated based on EIA
Delivery Cost for Natural Gas	EIA (AEO 2007)
Minemouth Supply Curve for Coal	EIA (AEO 2007)
Delivery Cost for Coal	EIA (AEO 2007)
Delivered Oil Price	EIA (AEO 2007)
Pollution Controls	
SO_2 – cost and performance	EPA
NO_x – cost and performance	EPA
Hg – cost and performance	EPA
Transmission	
Interregional Transmission Capacity	NERC
Inter and Intraregional Transmission Costs	EMF
Inter and Intraregional Transmission Losses	EMF
Demand	
Demand Level (by season and customer class)	EIA
Load Duration Curve	RFF
Demand Growth (by customer class and region)	EIA (AEO 2007)
Demand Elasticity (by customer class)	Estimated by RFF

Figure 3. The Haiku Electricity Market Model: Inputs and Output

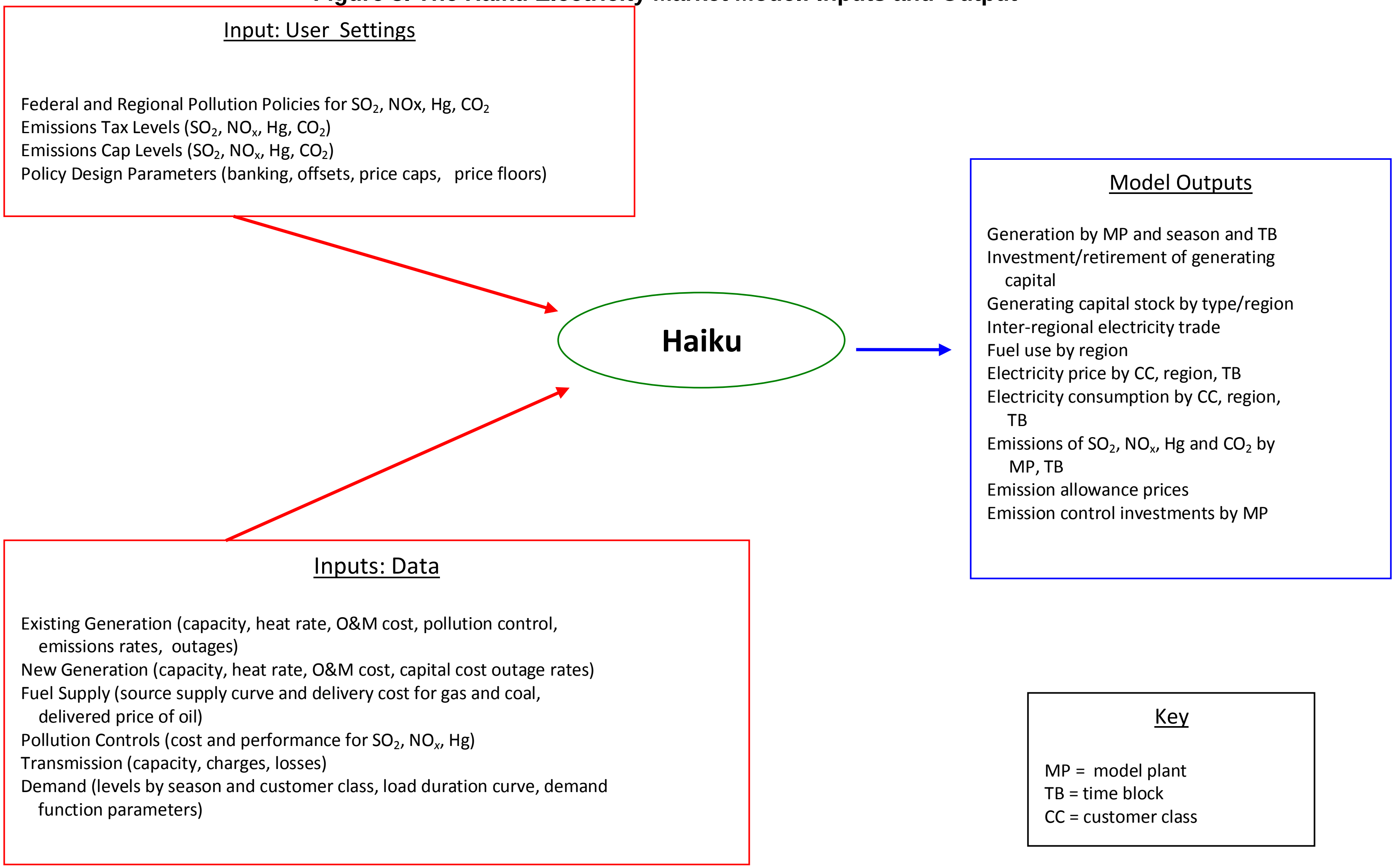


Figure 4. Haiku Market Regions and Electricity Pricing

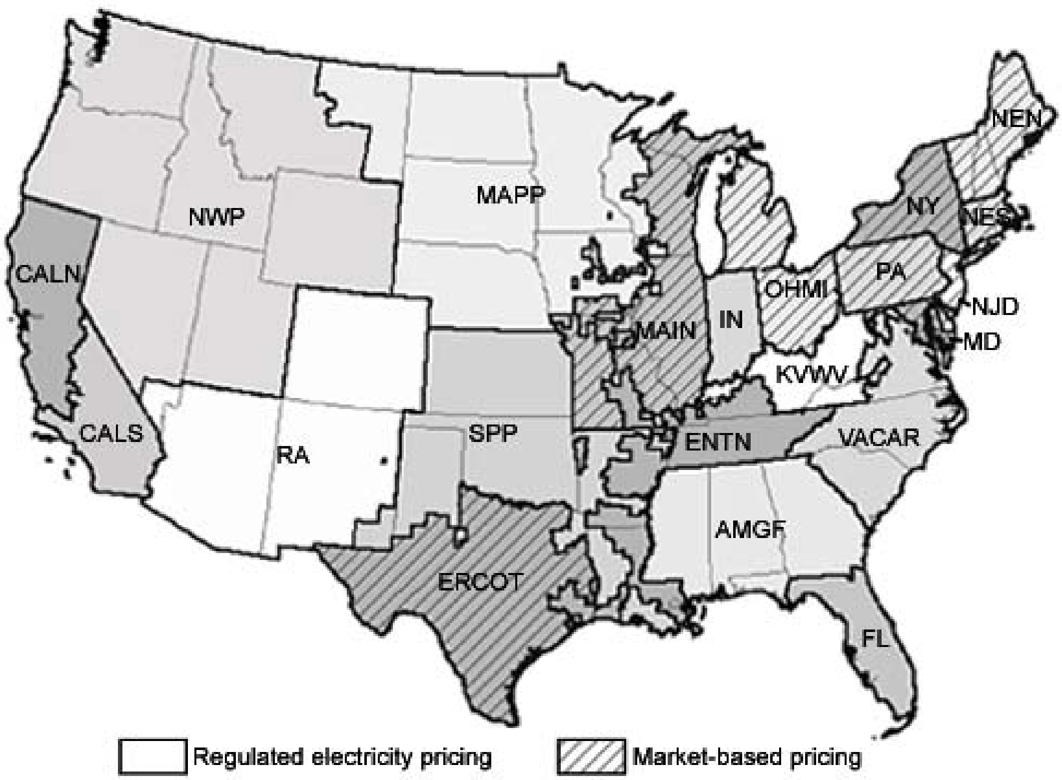


Table 2. Demand Elasticities in the Haiku Model

	Residential	Commercial	Industrial
Short-Run	-0.167	-0.118	-0.110
Long-Run	-0.649	-0.651	-0.605

Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial). Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity generation plants in the country. Investment in new generation capacity and the retirement of existing facilities is determined by the model in a framework that takes into account capacity-related costs of providing service in the future ("going forward costs") and future electricity prices that are assumed to be known today. Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation, including fuel costs, variable operating and maintenances cost and the costs of operating pollution control equipment plus the opportunity costs of using emissions allowances for those emissions subject to a cap-and-trade program.

Equilibrium in interregional power trading is identified as the level of trading of electricity between regions necessary to make marginal generation costs within each region net of transmission costs and power losses equal across neighboring regions. These interregional transactions are constrained by the level of the available interregional transmission capability as reported by the North American Electric Reliability Council (2003a, 2003b).[12] Factor prices, such as the cost of capital and labor, are held constant across different simulations of the model. Fuel prices for coal and natural gas vary according to the level of demand, and are benchmarked to the forecasts of the Annual Energy Outlook 2007 for both level and elasticity of supply (U.S. EIA 2007a). Coal is differentiated along several dimensions, including fuel quality and content and location of supply; and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. Other fuel prices are specified exogenously (i.e. they do not change within the model).

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions initiated under the 1990 Clean Air Act amendments, EPA's Clean Air Interstate Rule (CAIR) caps on emissions of SO_2 and NO_x (70 Fed. Reg. at 25,165), the Clean Air Mercury Rule (CAMR) (70 Fed. Reg. at 28,606) and the Regional Greenhouse Gas Initiative (RGGI) cap on CO_2 emissions (RGGI 2005), are imposed as constraints on the sum of emissions across all covered generation sources in the relevant region.[13] Emissions of CO_2 from individual sources

[12] Some of the HMRs are not coterminous with North American Electric Reliability Council (NERC) regions and, therefore, NERC data cannot be used to parameterize transmission constraints. Haiku assumes no transmission constraints among OHMI, KVWV, and IN. NER and NEO are also assumed to trade power without constraints. The transmission constraints among the regions ENTN, VACAR, and AMGF, as well as those among MAACR, MD, and PA, are derived from version 2.1.9 of the Integrated Planning Model (U.S. EPA 2005). Additionally, starting in 2014, the incremental transfer capability associated with two new 500-KV transmission lines into and, in one case, through Maryland, which are modeled after a line proposed by Allegheny Electric Power and one proposed by PEPCO Holdings are included (Ruth et al. 2008). The transmission capability between Long Island and PJM made possible by the Neptune line that began operation in 2007 is also included.

[13] CAIR was vacated by a three-judge panel of the U.S. Court of Appeals for the D.C. Circuit on July 11, 2008 in State of North Carolina, et al. v. EPA, and its status is uncertain. Legislative proposals have surfaced in the U.S. Congress that would introduce CAIR in statute.

depend on emission rates, which vary by type of fuel and technology, and total fuel use at the facility.

The sum of these emissions across all sources must be no greater than the total number of allowances available, including those issued for the current year and any unused allowances from previous years when banking, or holding of unused allowances from one year for use in future years, is permitted. To determine the rate at which the size of the allowance bank (i.e. the amount of cumulated unused emission allowances from past years) changes, the model imposes a Hotelling-type constraint that requires the rate of increase in the price of a durable asset such as emissions allowances from year to year to be no greater than the interest rate (Hotelling 1931). This constraint means that investments in emission allowances are assumed to compete with investment in other financial assets that grow in value over time at the rate of interest.

For this project California is disaggregated into two separate HMRs, CALN and CALS (N and S stand for north and south) to allows for a more accurate representation of power transmission congestion for cross-state trades – see Figure 4. The state is split by matching individual plants to local distribution companies (LDCs) using the EPA's National Electric Energy Data System (NEEDS) (U.S. EPA 2006) and to service areas using EIA forms 860 A and B. Plants are then assigned to a region based on the location of the LDC or service area. The amount of transmission capacity between the two regions is constrained to 3700 MW, which is the transfer capability reported for the EPA Base Case 2006 Integrated Planning Model.

3.2 Baseline Scenario and the AB32 CO_2 Cap

The analysis of the AB32 policy using the Haiku model is performed with reference to a baseline scenario. The baseline is designed to simulate the electricity sector in California (and beyond) in the absence of AB32 implementation. For this project, a baseline scenario is constructed that incorporates all major federal legislation governing airborne emissions from the electricity sector including the Title IV cap on national SO_2 emissions and CAIR for SO_2 emissions, the annual and ozone seasons caps on emissions of NOx under CAIR, and CAMR for mercury emissions. Also included are some state level legislation, including RGGI, and other policies that are specific to individual states. For nuclear capacity additions, Haiku uses the regional output of the U.S. Department of Energy's (DOE) National Energy Modeling System (NEMS) model Annual Energy Outlook for 2007 (U.S. EIA 2007a) as capacity limits on new construction of nuclear plants. All of these potential capacity additions are east of the Mississippi River.

The baseline scenario assumptions that are most important for California relate to the Federal Renewable Energy Production Tax Credit (REPTC) and state level Renewable Portfolio Standards (RPS) in several western states, including California. The REPTC provides a production tax credit of $19/MWh to new wind, geothermal, and dedicated biomass generators, and a credit of $9.50/MWh is available to new landfill gas and non-dedicated biomass generators.

Since the federal REPTC has repeatedly been renewed just prior to lapsing and has actually lapsed three times before being reinstituted, it is modeled in perpetuity in Haiku as a tax credit that is received with 90 percent probability, to reflect roughly the amount of time that it has been in effect since initiated in the early 1990s. The state level RPS mandates within the Western Electricity Coordinating Council (WECC) region, including a 20 percent standard that is modeled for California, require substantial increases in renewables generation in the coming years. The resulting capacity additions are not modeled endogenously within Haiku. Instead, new renewable capacity was added in the in order to meet these standards in the western states according to forecasts provided by Energy and Environmental Economics, Inc (E3, 2008).14 These forecasts of renewable resource additions that E3 forecasts would be needed to meet RPS standards are built by assumption in our analysis.

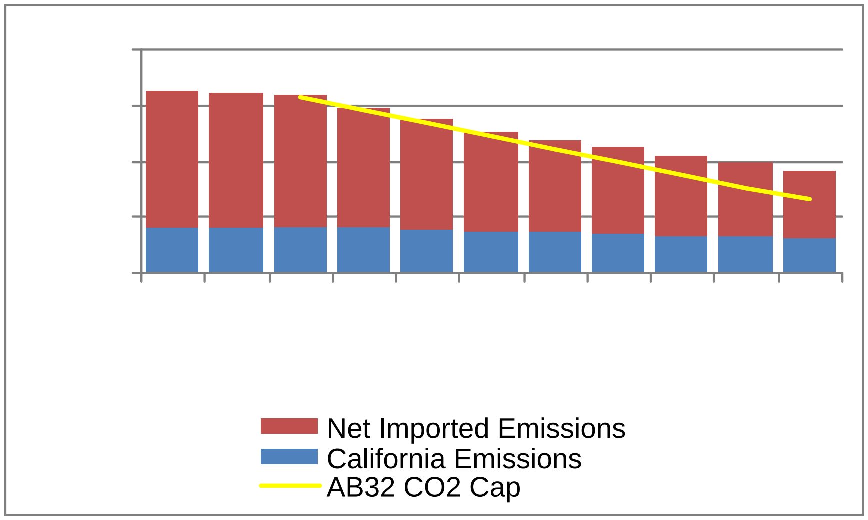
In order to model the effects of the AB32 policy, this study specifies the level of the cap on CO_2 emissions from electricity generators in California that will be stipulated under the AB32 policy, or, in the case of a broader-based cap-and-trade policy, an emissions level that reflects the level of reductions expected from the electricity sector. The exact parameters for the cap-and-trade policy have not been decided yet, but the economywide CO_2 reduction target for 2020 is about 25 percent below the anticipated 2020 business-as-usual level. Preliminary modeling and reading of research at the California agencies indicates that reductions required from the electricity sector in 2020 will be closer at least 30 percent under a cost-effective implementation of the policy, compared to the baseline level.

In the ARB Scoping Plan, the assumption is that the emissions reductions under a host of measures complimentary to AB32 (including efficiency and enhanced renewables standards) will be roughly 1/3 of expected baseline emissions and that the cap and trade program will yield even

[14] The western states where new renewables capacity was forced include California, Arizona, Montana, Colorado, New Mexico, Utah, Nevada and Wyoming.

greater reductions than that, bring emissions in the sector down to something between 59 and 94 million metric tons in 2020 (CARB 2008). In this analysis the assumed emissions reductions of 30 percent below the baseline, which includes a continued production tax credit for renewables generation and thus lower CO_2 emissions than the CEC baseline, will yield total annual emissions from the electricity sector of roughly 64 million tons in 2020.

Figure 5. Baseline Emissions and the AB32 Cap



The cap on California electricity sector CO_2 emissions that is used in the simulation modeling is phased in over the forecast horizon based on a straight line decline from 1 percent below the 2012 baseline level of emissions to 30 percent below the 2020 baseline level in 2020. The cap is held constant starting in 2020 until the end of the modeling horizon in 2025. The cap encompasses all CO_2 emissions associated with California electricity consumption, i.e. emissions from CA generators as well as those from out-of-state generators that are derived from CA electricity demand are included under the AB32 cap. Figure 4.2-1 shows CA emissions and emissions from CA net imports in the baseline scenario. The yellow line indicates the AB32 cap levels: 156.4 million tons of CO_2 emissions in 2012 and 64.1 million tons in 2020.

Note that strictly imposing this declining emissions path from 2012 through 2020 (and then flat thereafter) precludes the banking of allowances not used in early years of the program for use in the future, in order to avoid ambiguities about the compliance target; AB 32 provides that the emissions in 2020 will strictly conform to the cap. However, if the program does allow for banking of emissions allowances, then the allowance prices that result will tend to be higher than what is predicted in the early years of the program as a bank is built up, and prices will be lower in the later years as the bank is drawn down. This price differential occurs because banking increases demand for allowances of early vintages that can be used for compliance in future years and the existence of the bank reduces allowance scarcity in later years, thus lowering the value of allowances with later vintages relative to the “no-banking” case that is modeled.

Table 3. Baseline CO_2 Emissions and Emissions Cap, 2020

Baseline CO_2 Emissions (million tons)	
Total	91.4
CA South	17.2
CA North	13.9
Net Imports	60.2
Emissions Cap	
CO_2 (million tons)	65.1
Annual Averages of Assumed Import Emissions Rates (tons/MWh)	
RA	0.57
NWP	0.25

The model does not include the possibility of purchasing or financing greenhouse gas emissions reductions outside of the capped sector to offset emissions within this sector. Some use of offsets from other sectors likely to be allowed under the AB 32 program (CARB 2008). By not allowing for offsets this analysis is likely overstating the cost of meeting the AB 32 cap.

The CO_2 emissions imported to California are those emissions that are generated outside of California to meet electricity demand inside of California. These are projected using an incremental emissions rates approach intended to reflect the emissions associated with the incremental MWh produced in neighboring states that are generated to serve customers in California. The first step in calculating an emission rate for imported power is to perform a closed-border subbaseline simulation, which is identical to the baseline except that power trading between California and its neighbors is constrained to zero. This subbaseline scenario precludes any of California’s power needs from being met by imports to the state. The difference between the regular baseline and the closed-border subbaseline provides a measure of the incremental CO_2 emissions and incremental electricity generation in the NWP and RA regions that result from power trading with California.[15] The emission rates associated with imports are calculated

[15] The NWP region includes the states of Oregon, Washington, Nevada, Utah, Idaho, most of Montana and Wyoming. The RA region includes Arizona, Colorado and most of New Mexico.

using seasonal and time-block specific changes in emissions and generation in the two neighboring regions and these time-block specific rates are used to find emissions values related to imports in subsequent policy simulations. Table 3 shows the average annual values of the import emissions rate for NWP and RA, the two regions that trade power directly with California.

An alternative methodology is contained in the California Energy Commission (CEC) report "Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports" (Alvarado and Griffin, 2007). The report presents a method described as a marginal analysis and sales assessment to assign a generation mix to imported power, and applies the method to the year 2005. When a California LSE owns an out-of-state generator or a generator is a party to a specific contract with a California LSE, the MWh of generation and its generation type are directly assigned to LSEs. The remaining portion of imported power is designated as coming from an unspecified source.

Where similar commitments exist in neighboring regions, or where there are constraints on generation in order to serve local load outside of California, the authors assign power from specific out-of-state generators to out-of-state LSEs. This approach identifies the resources in the neighboring regions that are available to generate power for export from those regions to California, and they use information about what facilities are likely to be on the margin at various times of day in the Southeast to assign a resource type to the unspecified portion of imports.

In 2005, under this approach, 12 percent of imports were unspecified (suggesting that the majority could be assigned to particular generating units) and that 96 percent of that small unspecified fraction came from natural gas and 4 percent from coal. In total, over 57 percent of the total imports from the Southwest to California come from coal, 28 percent from natural gas and 11 percent from nuclear. In the Northwest, a slightly different approach is used, where a generation type is attributed to unspecified imports using a sales assessment that identifies the overall resource mix of the entity selling power to California or, in some cases, the specific source identified by the entity selling power to a purchaser in California. In 2005, 88 percent of imports from the Northwest were unspecified (not assigned to a particular generating source) with 66 percent of that unspecified total coming from hydropower, 22.1 percent from natural gas, 8.8 percent from coal, 1.7 percent from nuclear, and 1.4 percent from renewables.

The results of this study's methodology are compared for calculating the CO_2 emissions intensity of imports with the findings from the CEC methodology. To do so, the aggregate CO_2

emissions rates for imported power that are calculated by Alvarado and Griffin for 2005 to the four years prior to 2005 are used, assuming the estimated 2005 resource mix holds for all the years. Table 4 shows the historical net power imports into California and the associated emissions of CO_2 estimated using this methodology. These estimates are compared with Haiku forecasts for future years developed using this study's incremental emission rate approach described above. The anticipated growth of net imports in the Haiku model estimation is roughly consistent with the historic trend. Imports grew about 36 percent between 2001 and 2005, or 5.5 billion KWh (BkWh) per year, according to CEC. The Haiku model projects a growth rate of 35 percent between 2010 and 2020, or 4 BkWh per year.

Table 4. Emissions and Generation Comparison for Electricity Imports

Estimated from CEC "Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports"			
Year	Net Imports (BkWh)	Net Imported CO2 Emissions (Mtons CO2)	Average Emissions Rate (ton/MWh)
2001	60	41	0.68
2002	83	47	0.56
2003	81	48	0.59
2004	87	53	0.61
2005	82	50	0.61
Haiku Model Results			
Year	Net Imports (BkWh)	Net Imported CO2 Emissions (Mtons CO2)	Average Emissions Rate (Mton/BkWh)
2010	113	121	1.07
2011	114	120	1.05
2012	116	118	1.02
2013	120	108	0.90
2014	124	98	0.79
2015	128	88	0.69
2016	133	83	0.62
2017	138	77	0.56
2018	143	72	0.50
2019	148	66	0.45
2020	153	60	0.39

The estimates for total emissions are not as consistent across the two sources and time frames. In 2010, the Haiku estimated emissions rate for power imports is 1.07 tons CO_2/ MWh, about 75 percent higher than the CEC estimated emissions rate for 2005. The difference is attributable to the differences in the techniques used to estimate emissions. CEC estimates that 26 percent of imports are generated by natural gas, a relatively low carbon emitting fuel compared to coal and 28 percent by nuclear, hydro or other renewables, which emit no carbon. The CEC's analysis assumes these suppliers would not be running if the region was not exporting power to California but in fact it is unclear which generation resources would be utilized less in the absence of demand for power from California.

Because some of the resources identified by the CEC have low variable cost, such as nuclear, hydro and other renewables, it is likely that these facilities would be run to serve demand outside California and other facilities with higher fuel costs would be utilized less if California were not part of the transmission grid. The Haiku model, on the other hand, calculates equilibrium generation capacity, prices, generation, and emissions for the entire region (and country) when California is both on and off of the grid. The difference in emissions between these two baselines provides a unique way to think about out-of-state incremental generation that occurs specifically to meet electricity demand in California.

Over time the resource mix forecast in Haiku changes. Consequently, the incremental emissions rate for imported power drops almost 2/3 between 2010 and 2020 in the Haiku projections and approaches the estimate by the CEC for 2005, as illustrated in Table 4. The change in Haiku is due to growing renewable capacity throughout the West that includes an expansion in renewable generation to meet state RPS standards, and to take advantage of the federal Renewable Energy Production Tax Credit, which is assumed to be renewed with a probability of 90 percent in each future year (based on the experience in the past with renewal and lapses in this policy).

3.3 Policy Scenarios

Several different policy scenarios are considered and are defined by two characteristics. The first is the geographic scope of the cap-and-trade program, and the second is the approach to allocation of emissions allowances.[16] The combinations of program scopes and approaches to allocation that are modeled are illustrated in Table 5 and described in the next few paragraphs.

While AB32 is clear that emissions from imported power must be addressed by the implementing regulations, exactly how emissions from imports will be treated under a future cap-and-trade program is yet to be determined. Also, while California moves ahead with developing its approach to implementing AB 32, the Western Climate Initiative (WCI), in which

[16] For a discussion of the options and staff analysis see CPUC and CEC, 2008.

California participates, is also moving ahead with developing a regional CO_2 cap-and-trade program that could be operational in a similar time frame to that proposed in AB32. In light of these uncertainties and simultaneous developments, two different approaches to the scope of a trading program imposed on the electricity sector were considered, as shown in the column headings in Table 5.

The "California-only" approach is a first-deliverer regulation, with an estimated emission intensity assigned to imported power, as described above. Under this scenario, the estimated emission rate associated with generation to serve California electricity consumption is applied. Although this rate varies with the region from which power is imported and it varies over time, it is held constant with respect to changes in the level of imported power identified in the simulation. That is, the assumed emission rate is applied equally to all imported power coming from a given region in a given year. Importers have to hold sufficient allowances to cover their estimated emissions of CO_2, as do native generators in California.

The second program scope is a western regional CO_2 cap-and-trade program that applies to all electricity generators in the Western Electric Coordinating Council (WECC) region. This program scope is a proxy for an electricity focused program under the WCI. Seven of the 11 states in the WECC, including California, are full participants in the WCI as are three Canadian provinces.[17] Under the modified WCI cap-and-trade program that is modeled, it is assumed, consistent with WCI plans, that the program will require reductions in emissions from electricity generators in the region of 30 percent from baseline levels in 2020.[18]

Table 5. Matrix of Climate Policy Scenarios

Scope: / Allocation:	California Only.	Modified WCI Region
Auction	x	x
Load-Based Allocation	x	x

[17] The other WECC states plus Alaska and Kansas are official observers to the WCI as are several Mexican states and two Canadian provinces.

[18] The WCI regional goal is to achieve a 15 percent reduction below 2005 levels by 2020. The target modeled in this study is a 30 percent reduction below the baseline level of emissions predicted in the model for each simulation year.

The two approaches to allowance allocation are summarized in the rows in Table 5. These include an **allowance auction** and **allocation to local distribution companies (LDCs)** on the basis of the size of the population served by the LDC. Under an auction, in-state generators and power importers in the California-only scenario must purchase CO_2 emission allowances from the government and then surrender them to cover their CO_2 emissions. Under the allocation to LDCs, allowances are allocated for free to LDCs, and generators and importers must purchase allowances from the LDCs to whom they have been awarded. The ability to sell allowances that it received for free gives the LDCs an additional source of revenue that helps to offset the increase in the wholesale price of power associated with the new CO_2 price in the economy. This revenue lowers the portion of total costs that needs to be recovered from electricity customers. As a result, the price of electricity paid by all classes of customers is expected to be lower with load-based allocation than with an auction approach.

Allowance allocation has become an important focus of recent political debates about CO_2 cap-and-trade programs at the federal level and within Europe as well as in California. Most of the arguments in these debates are motivated by concerns about the high potential costs of these programs and who will bear them. However, how allowances are allocated can have implications for the efficiency of the cap-and-trade program as well. This is particularly true within the context of the electricity sector. In many states, including California, this sector is subject to cost-of-service regulation, and thus the opportunity cost of freely granted emissions allowances (based on some historic measure) will not be reflected in electricity prices the way they would be in regions where prices are set in the market (Burtraw et al. 2001).[19]

4. Findings from Simulation Analysis

The electricity market simulation model is used to analyze the effects of allowance allocation and geographic scope of the cap-and-trade regulation on electricity markets in California and beyond, allowance markets, greenhouse gas emissions, and emissions of pollutants that affect local air quality in California. Issues of key concern include the potential for emissions leakage and how it is affected by the method of allocation. The study also

[19] Other free approaches to allocation include free allocation to generators on the basis of historic emissions or on the basis of recent generation. These approaches are not modeled here because there is no unambiguous way to calculate the historic emissions of sources outside the state that occurred historically in order to serve California. In addition, these approaches are not under active consideration as approaches for the California policy.

considers how a key baseline assumption regarding the future of federal policy to promote renewables affects the analysis.

Table 6. Overview of Policy Scenario Results, 2020

Scenario	*Baseline*	*California Only (Auction)*	*California Only (Load-Based))*	*Modified WCI (Auction)*	*Modified WCI (Load-Based)*
California					
Avg Elec price (2004$/MWh)	*106.7*	*118.8*	*113.0*	*110.2*	*104.6*
Generation (bill. kWh)					
Coal	2.7	2.7	2.7	2.7	2.7
Natural Gas	49.4	58.3	69.7	35.2	58.5
Nuclear	34.8	34.8	34.8	34.8	34.8
Oil	6.6	2.3	0.5	5.7	5.7
Non-hydro Renewables	*56.3*	*75.8*	*76.0*	*68.8*	*71.0*
Total	*192.3*	*216.2*	*226.0*	*189.6*	*215.1*
Imports (bill. kWh)	152.6	116.7	114.8	149.6	132.3
New Capacity[a] (GW)					
Gas	*11.1*	*12.6*	*12.6*	*8.1*	*10.6*
Wind	*7.6*	*7.6*	*7.6*	*7.6*	*7.6*
Biomass	*0.0*	*3.1*	*3.4*	*2.0*	*2.3*
Geothermal	1.7	1.7	*1.7*	*1.7*	*1.7*
Total	*21.3*	*25.8*	*26.2*	*20.3*	*23.1*
CO_2 Price (2004$/ton)	----	47.2	102.9	17.2	21.4
Emissions					
NO_x (thousand tons)	20.9	9.8	6.9	10.9	12.8
SO_2 (thousand tons)	9.8	8.9	2.2	9.7	10.0

CO_2 (million tons)	31.1	28.7	29.5	24.1	33.4
Rest of West[b]					
Avg Elec price (2004$/MWh)	*72.6*	*71.3*	*69.7*	*80.4*	*76.1*
TOTAL Gen. (bill. kWh)	*639.5*	*607.8*	*611.7*	*608.6*	*600.9*
TOTAL Cons. (bill. kWh)	460.8	464.0	466.0	439.9	452.7
Entire West					
CO_2 Reduction (mill. tons)		19.5	14.5	103.4	103.8

The results of the simulation analysis of the four scenarios are summarized and contrasted with those for the baseline scenario in Table 6. This table shows the effects on the average electricity price, the mix of fuels used to generate electricity, the amount of imports into California, and the effects on investments in new capacity for the year 2020. The table also includes projections of allowance prices and emissions of SO_2, NOx and CO_2 in California under the different scenarios.

4.1 Auction

The first approach to allocation that is considered is an auction.

4.1.1 California-Only Cap and Trade

The imposition of a cap-and-trade program on electricity sector CO_2 emissions in California-only, using the first-deliverer approach, and with an allowance auction, has important effects on electricity prices, electricity imports, and the mix of generators used to produce electricity in California. Under the allowance auction case, the average electricity price in California in 2020 is 11 percent higher with this policy than under the baseline, and electricity demand is 3.7 percent lower. Imports into California are 24 percent lower in 2020 as a result of the policy suggesting that the first deliverer approach helps to stem the growing reliance on power imports in 2020 that occurs in the baseline scenario. The lower level of demand brought about by the policy means that only part of the reduction in imports needs to be made up by greater in-state generation, and the resulting increase is comprised of a combination of higher generation with natural gas and roughly 50 percent more generation from non-hydro renewables compared to the baseline. The price of an emission allowance under this policy is $47.20 per ton of CO_2 in 2020.

Imposing the California-only policy results in an average electricity price in the regions that surround California that is nearly 2 percent lower than in the baseline scenario in 2020.[20] The decline in retail prices outside of California contributes to emissions leakage (see below). The usual rationale for leakage is that generation outside the regulated region increases to meet demand in the regulated region. Hence, an increase in consumption outside the regulated region is not the usual rationale for leakage.

4.1.2 Leakage and Grid Usage

Emissions leakage is a concern for policies intended to restrict emissions of greenhouse gases. Because climate change is a global problem, the location of CO2 emissions does not matter, and if efforts to reduce emissions in one location lead to increases in another, the effectiveness of the policy is reduced. Concerns about leakage have confounded efforts to control emissions of CO2 within the U.S. because of the lack of such commitments on the part of trading partners including China and India, countries that could also become magnets for industries seeking to avoid regulations in the US and Europe.

Concerns about leakage also plague regional programs within the U.S., the largest and most developed of which is the Regional Greenhouse Gas Initiative (RGGI) that caps emissions of CO2 from electricity generators in 10 northeastern states beginning in 2009. Estimates of leakage under this program range substantially: Burtraw et al. (2005) reported leakage estimates of between 17 and 40 percent of emissions reductions brought about by the program over a decade of operation when allowing for investments in new capacity, while Chen and Sauma (2008) found that, in the short run, leakage from RGGI could be closer to 70 to over 90 percent of CO2 emissions reductions in the RGGI region.

[20] It is not obvious what expectations about the effect of this policy on prices in neighboring regions would be ex ante. Retail prices in the regions neighboring California are assumed to be regulated at approximate average cost, and inter-regional trade is determined by differences in the marginal generation cost between neighboring regions. Revenue from exported power is assumed to accrue to ratepayers in the exporting region thereby lowering the revenue requirement in the region that has to be recovered from native customers; therefore, an increase in exports should lower native retail price. However, if marginal generation cost in an exporting region is not increasing as the level of generation increases, then the retail (average) cost in the exporting region may rise as long as it is below marginal cost.

In a study of what the RGGI states might do about leakage, the RGGI Emissions Leakage Multi-State Staff Working Group (2008) stresses the possibility of a national plan as a way of addressing the leakage problem. They conclude that RGGI states should monitor leakage and implement leakage mitigation measures with demonstrated effectiveness and short implementation time frames. Examples of these are aggressive increases in investment in energy efficiency market transformation programs and complementary policies such as building energy codes and appliance and equipment efficiency standards that accelerate the deployment of end-use energy efficiency technologies and measures. The report recommends against using policies such as emissions portfolio standards and load-based compliance requirement at the current time, but recognizes that these and other measures are deserving of future study because they could be useful if end-use energy efficiency measures prove insufficient as a leakage mitigation approach or action toward the implementation of a federal cap-and-trade program is significantly delayed. Initially there will be no explicit accounting for the change in emissions that might occur out of the region in order to provide power to consumers in the region.

In the case of the California-only policy, emissions leakage was measured as the change in CO_2 emissions in the Western Electricity Coordinating Council (WECC) region that offset the reductions required under the California policy, which is equal to 26.2 million tons in CO_2 emissions reductions in 2020. Emissions leakage can come from growth in power imports into California as a result of the policy, or from changes in the generation mix or electricity consumption in the neighboring regions.

Emissions leakage from demand for imports is constrained by the capacity of the electricity transmission grid between California and it neighbors. The Haiku model imposes an exogenous growth rate for interregional transmission capability of 1.5 percent per year, which could come from new or expanded lines or software upgrades. If the transmission constraint is met in 2020, such that California maximizes its net power imports, then using the emission rate calculated from the baseline, those imports would account for 65.5 million tons of CO_2 emissions in NWP and RA. Under the state-wide cap, emissions associated with imports to California will fall to around 36.5 million tons of CO_2, or approximately 56 percent of the maximum potential. The “Grid in Use (%)” row of Table 7 shows this metric for each of the scenarios.

This study’s findings with respect to total emissions leakage are summarized in Table 7 in the row labeled “Leakage (%)”. This measure of leakage is calculated as the change in total emissions in the WECC relative to the baseline, divided by the emissions reduction goal of the policy (26.2 M tons of CO_2 in 2020). Any changes in CO_2 emissions beyond the WECC are ignored by this measurement of leakage. These results suggest that leakage will depend on how allowances are allocated. Under an auction, leakage would offset roughly 25 percent of the emissions reductions resulting from the program.

Table 7. Emissions Measures, 2020

Scenario	*Baseline*	*California Only (Auction)*	*California Only (LBA)*
CO_2 Emissions [M tons]			
CA	**31.1**	28.7	29.5
NWP	**125.6**	122.8	128.2
RA	**188.2**	174.0	172.9
WECC Total	***345.0***	*325.5*	*330.5*
Policy Reductions Goal [M tons]		*26.2*	*26.2*
Policy Reductions [M tons]			
CA		2.5	1.7
NWP		2.8	(2.6)
RA		14.2	15.4
WECC Total		*19.5*	*14.4*
Leakage [%]		26%	45%
Grid in Use [%]	**92%**	56%	54%
CO_2 Emissions Rate of Exports to CA [tons/MWh]			
NWP	**0.25**	------	0.45
RA	**0.57**	0.44	0.46

The California-only scenarios impose an assumed emission rate on generation in NWP and RA of 0.25 tons/MWh and 0.57 tons/MWh, respectively. These emission rates are derived, as described in Section 4.2, from the difference between the baseline scenario and a subbaseline in which no power is traded between California and its neighbors. The bottom section of Table 7 shows these baseline emission rates, as well as the emissions rates associated with incremental generation in neighboring regions that obtain under each scenario.[21] When the emission rate varies from that calculated from the baseline scenarios, it indicates a change in the overall composition of the resource mix. In the model solution for the auction scenario, the imports from

[21] This is calculated as the change in emissions for each scenario relative to the baseline, divided by the change in generation.

RA have an emission intensity that is roughly comparable to that assumed in the model. There is very little incremental generation from NWP, and the emission rate is unchanged.

4.1.3 The Modified WCI Policy

One way to address the CO_2 emissions leakage problem would be to expand the cap-and-trade program to cover a larger geographic region. A West-wide cap-and-trade program was modeled with modified WCI scenarios, one with an auction approach to initial allocation and one with load-based allocation. The modified WCI policy imposes a 30 percent reduction in CO2 emissions from baseline levels in 2020, with a gradual decline in the emissions cap from 2012 until 2020, and then holds the cap at the 2020 level in subsequent years.

In addition to limiting leakage, a region-wide cap would yield a substantially lower CO_2 allowance price and a smaller increase in electricity price in California than a California-only policy. When the regional policy is combined with an allowance auction, the CO2 allowance price is $17.20 per ton in 2020, slightly more than 1/3 of the allowance price level with a California-only policy. Electricity price in California rises by 3.2 percent in 2020, again about 1/3 as much as it does with a California-only cap and an auction.

Moving from a state-specific policy to region-wide CO_2 emissions cap has important implications for power trading and what resources are used to generate power in California. Because the broader regional cap is a source-based policy, there is no compliance requirement on power importers and that results in a much smaller drop in power imports into California as a result of the cap. With a modified WCI policy coupled with an allowance auction, power imports to California are only slightly lower than baseline levels. However, natural gas-fired generation within California is about 30 percent lower under the policy than in the baseline, and investment in new natural gas capacity is below baseline levels. Oil-fired generation within California, which falls dramatically under a California-only policy, only declines slightly under the WCI policy.

As expected, the region-wide policy has larger effects on California's neighbors than would a California-only policy. Average electricity price in the rest of the West increases more than 10 percent from baseline levels, and total consumption falls by 5 percent when the modified WCI policy is coupled with an auction. Total generation in the regions surrounding California falls by a comparable amount. The largest change is a reduction of 64 BkWh in coal-fired generation and a decline of 29 BkWh in gas generation, while renewable generation increases by 56 BkWh.

4.2 Load-Based Allocation

When allowances are auctioned to those entities that need them for compliance with the cap-and-trade regulation, the costs of those allowances are fully reflected in the price of electricity to consumers in California, and, under the California-only policy that is modeled, an 11 percent increase in price is seen. One way to reduce the price impact of the policy would be to allocate allowances to LDCs, the regulated companies responsible for the wires that facilitate delivery of power to final consumers. Power generators and first deliverers of imported power would be required to purchase allowances from the LDCs, or alternatively allowances could be auctioned centrally with the revenues being returned to the LDCs. This approach provides another source of revenue to these regulated companies, which allows them to lower what they charge customers for electricity.[22]

Allocation to LDCs may be done on the basis of several different metrics including population, electricity demand and even emissions.[23] For this analysis, a population-based approach was used. Relative to a consumption-based approach, the population-based approach rewards past investment in energy efficiency and efforts to keep consumption per person low. California may view a consumption-based approach as especially perverse, given the state’s previous and ongoing efforts to reduce energy consumption. An emissions based approach would be difficult to implement in California, given the near impossibility of assigning allowances to imported power, an important source of electricity related CO_2 emissions.

The load-based approach to allocation substantially attenuates the effect of the cap-and-trade policies on average retail electricity price in California. As shown in Table 6, under the

[22] An alternative approach would be to refund the allowance revenue to consumers on a per capita or per household basis. This approach, known as cap and dividend, would help to lower the impact of the greenhouse gas cap and trade policy on electricity consumers, but would do so in a way that would not affect the price they pay for electricity. As such its effects on electricity markets and allowance markets would be identical to the auction based approach discussed in section 5.1.

[23] In each of these approaches to load-based allocation, the allowances are distributed to the local distribution companies and revenue from the sale of these allowances (received at zero cost) are assumed to be used to partially offset the revenue requirement of the LDC, thus allowing it to lower its price for distributing electricity and, in the case when the LDC is also the load-serving entity, for supplying the electricity to customers. Load-based allocation could take the form of allocating allowances directly to LDCs, which would then be responsible for seeing them, or it could take the form of holding a single allowance auction and then allocating the revenues from that auction to LDCs based on one of the measures identified. An emissions-based approach to load-based allocation has been endorsed by the National Association of Regulatory Utility Commissioners (April 21, 2008). See Paul et al (2008) for a discussion of the implications of different approaches to load-based allocation of allowances under a national CO2 cap and trade program.

California-only policy, the electricity price increase in 2020 with load-based allocation would be only 6 percent compared to a more than 11 percent increase under the auction. The lower electricity price means electricity demand would be higher. This is partially met by more generation from natural gas plants within California, but it also has a positive effect on leakage, compared to the auction scenario. Table 7 indicates that there is little difference in the emission rate that is associated with imports from RA. However, there is a significant difference in the emission rate associated with incremental generation from NWP, where the emission rate is greater than that assumed in the model.

The lower electricity price does come at a cost. The policy would yield a more than 100 percent increase in the price of CO_2 emission allowances in 2020. With a smaller increase in electricity price, electricity consumers have a weaker incentive to conserve electricity, which means that there will be more demand for the fixed quantity of emission allowances, thus driving up their price. This has implications for other parts of the California economy as well, as discussed below.

Under the Modified WCI policy, the load-based approach to allocation actually would reduce electricity price in California to a level 2 percent below baseline price. This result reflects the fact that California is the most populous state within the Western states region and thus, under a population-based approach to load-based allocation, LDCs in California get a substantial share of the value of the emissions allowances created by the program. The lower price means that total electricity demand in California would be higher than baseline levels and more generation from renewables and natural gas fired generators would be brought on to fill the gap on the supply side. As shown in the bottom section of Table 6, the average electricity price in the rest of the West would be higher than baseline levels, but lower than the price obtained if an auction was used to implement the Modified WCI policy.

While the effect of load-based allocation on allowance price is much less pronounced with the Modified WCI than it is with the California-only policy, allowance price would still be 24 percent higher than under the auction. Thus, using this approach to compensate electricity consumers for the cost of a climate policy will come at a cost that will be felt beyond the electricity sector by all parties who must hold allowances to cover their CO_2 emissions.

4.3 Ancillary Benefits in California

Some concerns about a cap-and-trade approach in California stem from the fear that allowing firms to trade CO_2 emissions could result in increases in emissions of pollutants, such as NO_x and SO_2, that have local air quality effects and that these increases might be particularly damaging to low-income populations that tend to live in closer proximity to fossil-fueled electricity generators and other industrial facilities. This study's results suggest that a cap-and-trade program for CO_2 emissions in California will typically result in substantially lower emissions of NO_x from the electricity sector. Impacts on SO_2 emissions are mixed and vary across scenarios as shown earlier in the summary table.

Table 8 shows emissions of NO_x and SO_2 under the different scenarios separately for the northern and southern regions of California. Emissions of NO_x fall in both the northern and southern parts of the state when CO_2 cap-and-trade policies are imposed. In Northern California, the drop in NO_x emissions is greater with a California-only policy than with the Modified WCI policy, assuming a common approach to initial allocation. The lowest level of NO_x emissions in both regions occurs under a California-only policy with a load-based approach to allocation. This study's model does not include the effects of local air quality restrictions on emissions of these pollutants nor does it reflect reductions required by the RECLAIM program.

Table 8. Emissions of Local Air Pollutants, 2020

Scenario	*Baseline*	*California Only (Auction)*	*California Only (LBA)*	*Modified WCI (Auction)*	*Modified WCI (LBA)*
Northern California					
NO_x (thousand tons)	10.3	4.9	3.5	6.4	6.9
SO_2 (thousand tons)	7.3	6.3	1.2	7.2	7.3
Southern California					
NO_x (thousand tons)	10.6	5.0	3.4	4.5	5.9
SO_2 (thousand tons)	2.4	2.6	1.1	2.5	2.6
Total California					
NO_x (thousand tons)	20.9	9.9	6.9	10.9	12.8
SO_2 (thousand tons)	9.8	8.9	2.3	9.7	9.9

Overall, the CO_2 policies have much less pronounced effects on emissions of SO_2 from California electricity generators. The one exception to this is the California-only policy with load-based allocation, which results in an over 80 percent reduction in SO_2 emissions from electricity in the northern part of the state in 2020 and a more than 50 percent reduction in the south. This is the same scenario that produced dramatic reductions in emission of $NO_{x,}$ and these reductions follow from the decline in oil-fired generation resulting from this policy. With a CO_2 emission allowance price in excess of $100 per ton, generating electricity with oil becomes prohibitively expensive. In the study's model, oil generators, generally deemed necessary to meet load in load pockets, have a strong incentive to run even at high levels of costs, but the allowance cost in this scenario more than offsets that incentive. In the real world, it is unclear the extent to which the generation services provided by must-run oil generators in California may be supplied by other resources.

In general, the results indicate that CO_2 cap-and-trade policies would not lead to NO_x or SO_2 emissions increases statewide, although there are slight increases in the southern part of the state under certain policies.

4.4 Alternative Renewables Policy Assumptions in the Baseline

The assumption that the federal REPTC will remain in effect in 9 out of 10 years for the indefinite future has an important effect on the amount of renewable generation in the future predicted by the model. This effect was analyzed by running an alternative baseline that excludes the extension of the REPTC policy into the future. As shown in Table 9, at the national level including the REPTC policy results in more than double the amount of non-hydro renewables generation in 2020 as occurs without the REPTC and 5 percent lower CO_2 emissions from the electricity sector as a whole. The REPTC also results in a slightly lower average electricity price and slightly more electricity consumption nationwide, which helps to limit the reduction in CO_2 emissions brought about by the REPTC policy.[24]

The effects in the western US outside California are more pronounced than those nationwide as shown in Table 10. In the two regions that border California, the policy has a dramatic effect on the role of non-hydro renewables generation, in large part because of the abundance of wind resources located in the NWP region. Total generation by non-hydro renewables is 125 percent higher and total CO_2 emissions from the electricity sector are nearly 12 percent lower in 2020 when the REPTC policy is extended than when it is not. When the REPTC is not extended, the generation mix in the combined regions bordering California is more

[24] Palmer and Burtraw (2005) also find that a production tax credit on renewables is not a cost-effective way to reduce CO2 emissions because it results in lower electricity prices and higher electricity consumption.

heavily weighted toward coal and natural gas, and the amount of power shipped into California is reduced.

Interestingly, in California eliminating the federal REPTC does not result in less non-hydro renewables generation. Instead, as a result of both the renewables that are brought on-line in California to help meet the 20 percent RPS policy and the fact that California would have to pay more for imported power without the REPTC, there would be roughly the same amount of non-hydro renewables generation within the state without the federal tax credit as with the federal tax credit for renewables. Without the REPTC, California does increase its reliance on fossil generators because importing power is more expensive. This increase in fossil generation, in turn leads to an increase in CO_2 emissions from in-state electricity generators of roughly 16.6 percent.

Figure 5 shows the time path of baseline CO_2 emissions from California generators and importers in the absence of the REPTC. Without the REPTC, baseline emissions actually rise slightly between 2010 and 2020, with all of the increase coming from emissions associated with power imports. Without the REPTC, the mix of generators that are used to produce power for export to California tend to be much higher emitting, with an average emission rate of roughly 0.8 tons per MWh. A CO_2 emissions cap in 2020 set on the basis of this baseline would be higher, but exactly how the price of allowances would be affected is difficult to predict given that having the REPTC in place lowers the cost of compliance with the cap.

Table 9. Effect of the REPTC Nationwide, 2020

Scenario	*Baseline*	*Baseline with no REPTC*
National		
Avg Elec price (2004$/MWh)	*81.4*	*82.9*
Generation (billion kWh)		
Coal	2,221.4	2,308.1
Natural Gas	681.6	786.2
Nuclear	831.7	837.3
Oil	71.1	79.2
Non-hydro Renewables	*456.7*	*216.5*
Total	*4,575.0*	*4,539.7*
Emissions		
CO_2 (million tons)	2,805.0	2,947.9

Figure 6. Baseline Emissions with no REPTC

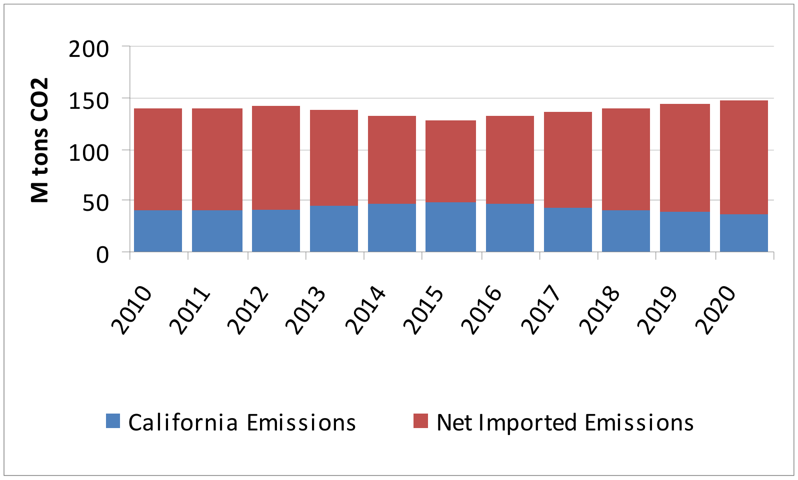


Table 10. Effect of the REPTC in California and the Rest of West, 2020

Scenario	*Baseline*	*Baseline with no REPTC*		*Baseline*	*Baseline with no REPTC*
California			**Rest of West**		
Avg Elec price (2004$/MWh)	*106.7*	*109.4*	**Avg Elec price (2004$/MWh)**	*72.6*	*73.7*
Generation (billion kWh)			**Generation (billion kWh)**		
Coal	2.7	2.7	Coal	252.4	295.6
Natural Gas	49.4	61.1	Natural Gas	50.1	55.2
Nuclear	34.8	34.8	Nuclear	39.5	39.5
Oil	6.6	6.8	Oil	0.8	1.6
Non-hydro Renewables	*56.3*	*57.1*	Non-hydro Renewables	*122.6*	*54.2*
Total	*192.3*	*204.9*	Total	*639.5*	*620.3*
Imports (billion kWh)	152.6	134.7	**Imports (billion kWh)**	-149.9	-133.8
New Capacity[a] (GW)			**New Capacity[a] (GW)**		
Gas	*11.1*	*10.1*	Gas	*13.8*	*13.8*
Wind	*7.6*	*7.6*	Wind	*23.6*	*13.8*
Biomass	*0.0*	*0.0*	Biomass	*0.0*	0.0
Geothermal	1.7	*1.7*	Geothermal	*4.4*	3.5
Total	*21.3*	20.3	Total	*48.7*	*36.4*
Emissions			**Emissions**		
NO_x (thousand tons)	20.9	24.4	NO_x (thousand tons)	537.0	568.2
SO_2 (thousand tons)	9.8	10.5	SO_2 (thousand tons)	294.2	298.1
CO_2 (million tons)	31.1	36.1	CO_2 (million tons)	313.8	356.4

5. Conclusion

An important challenge in designing a CO_2 allowance cap-and-trade program for implementing AB32 in California is how to allocate the CO_2 emission allowances created by the program. This decision will have important implications not only for the performance and effectiveness of the California program, but also for how that program helps to inform and shape a future federal economywide cap-and-trade program for greenhouse gases.

One approach that we modeled would keep the allowance value associated with historic emissions of CO_2 in the electricity sector by directing the value to local distribution companies, thereby subsidizing electricity consumption. An alternative approach would be to use allowance auctions with auction revenue available to be used for a variety of purposes. This study's results suggest that using a load-based approach to allocation within the electricity sector will cause greater marginal costs of emissions reduction in other sectors of the economy, raise total costs across the economy, and undermine the environmental initiative through emissions leakage.

The extent of emissions leakage in a California-only cap-and-trade program depends importantly on how emissions allowances are allocated. A load-based approach to allocation, with its relatively smaller effect on electricity price, leads to nearly twice as much emissions leakage as an auction approach. Expanding the scope of the cap-and-trade program to include all western states would eliminate leakage of emissions within the region and produce substantially more in CO_2 reductions at a lower allowance price. Also, contrary to the expectations of some stakeholders, simulation modeling indicates a cap-and-trade policy for CO_2 would reduce emissions of NO_x in the electricity sector.

Minimizing the politically unpopular effect on price has been an explicit objective of many advocates. The practical design of public policy success requires a transition in the changes in relative prices in the economy. This will lessen the cost of the program by lessening the economic disruptions associated with an abrupt change in policy.

If policymakers remain wedded indefinitely to an electricity price that does not reflect the scarcity value of CO_2 while other sectors of the economy are treated differently, then the marginal cost of emissions reductions will differ across the economy, potentially greatly increasing the cost to the economy of emissions reductions. It will also undermine consumer decisions with respect to investments in end-use efficiency because electricity will be priced below its marginal social cost.

Glossary

AB32	Assembly Bill 32
ARB	Air Resources Board
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCAR	California Climate Action Registry
CEC	California Energy Commission
CO_2	Carbon Dioxide
CO_2RC	CO_2 Reduction Credit
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
E3	Energy and Environmental Economics
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GEAC	Generation emission attribution certificate
HMR	Haiku market region
ISO	Independent System Operator
IOU	Investor owned utility
LDC	Local distribution company
LSE	Load Serving Entity
NEEDS	National Electric Energy Data System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NO_x	Nitrogen Oxides
NWP	the northwestern subregion of the Western Electricity Coordinating Council
PIER	Public Interest Energy Research
RA	the southwestern subregion of the Western Electricity Coordinating Council
RD&D	Research, development and demonstration
REPTC	Renewable Energy Production Tax Credit
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SO_2	Sulfur Dioxide
TEPPC	Transmission Expansion Planning Policy Committee
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

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