Greenhouse Gas Modeling of California's Electricity Sector to 2020:

Updated Results of the GHG Calculator
Version 3b update

Prepared for:

California Public Utilities Commission

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1 Overview

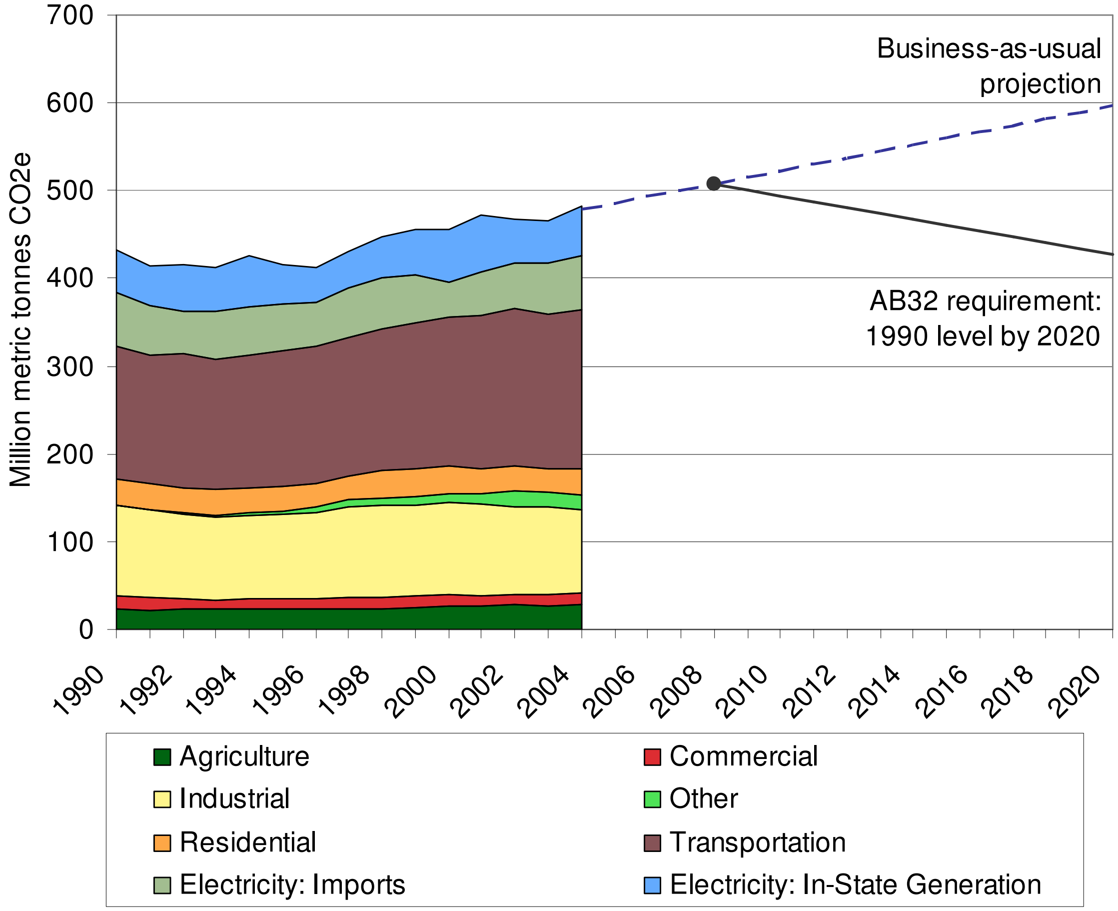
In 2006, California Governor Arnold Schwarzenegger signed into law the Global Warming Solutions Act, known as Assembly Bill 32 ("AB 32"). The law commits the state to reduce its emissions of greenhouse gases to 1990 levels by the year 2020. In July 2007, the California Public Utilities Commission ("CPUC") hired a team led by Energy and Environmental Economics, Inc. ("E3") to help the Commission understand the potential for reducing GHG emissions from the electricity sector to comply with AB 32 and the potential utility costs and impacts on California ratepayers.[1] This report presents the updated findings of that analysis effort, using California's most recent renewable energy cost data developed under the Renewable Energy Transmission Initiative.

The magnitude of the state's GHG emission reduction challenge is presented in Figure 1 below. The figure shows CARB's greenhouse gas emissions inventory for California from 1990 to 2004, by economic sector. In 1990, statewide emissions stood at 426.6 million metric tons of carbon dioxide equivalent ("MMTCO_2e"). If the state took no actions to reduce greenhouse gas emissions through 2020, CARB estimates that emissions would reach 596.4 MMT CO_2e under a "business-as-usual" scenario. Achieving AB 32 will require a 40 percent reduction in emissions across all sectors from the 2020 business-as-usual forecast, or a 10 percent reduction from the statewide average emissions level of 2002 – 2004.[2] AB 32 does not set a specific emissions target for the electricity sector or any other specific sector, including out-of-state coal generation, only for the state as a whole.

[1] The work was undertaken in the context of the Public Utilities Commission and the California Energy Commission's (CEC) joint greenhouse gas proceeding (CPUC Rulemaking 06-04-009 and CEC Docket #07-OIIP-01). The project was also partially funded by the California Air Resources Board.

[2] California Air Resources Board, "Climate Change Scoping Plan Appendices, Volume 1: Supporting Documents and Measure Detail, Appendix F Table 3, pg. F-7.

Figure 1. California Greenhouse Gas Emissions Inventory by Economic Sector (1990 – 2004), Business-as-usual Emissions Projection and AB 32 Emissions limit by 2020.



In 2004, the electricity sector comprised approximately 25% of the state's greenhouse gas emissions.[3] A little less than half of the electricity sector's emissions are the result of in-state electricity generation, and a little over half are derived from emissions associated with electricity imports.

This report describes the options and expected costs of reducing greenhouse gas emissions from the electricity sector. Section 1 presents an overview of the report and the key findings of the analysis. Section 2 describes the modeling methodology. Section 3 discusses the statewide electricity sector impacts of different 2020 scenarios. Section 4

[3] California Air Resources Board, "California 1990 Greenhouse Gas Emissions Level and 2020 Emissions Limit" (2007), www.arb.ca.gov/cc/ccei/inventory/1990_level.htm

describes the results of sensitivity analysis to key parameters of the 2020 scenarios. Section 5 discusses expected impacts of greenhouse gas reductions to specific California electricity retail providers. Section 6 provides an analysis of the impacts of a cap and trade policy on the Western electricity grid and on California's electricity sector, while Section 7 provides the report's conclusions.

1.1 Project Background

Under the Joint CPUC/CEC proceeding on greenhouse gas ("GHG") reduction strategies, E3 developed a publicly-available spreadsheet-based model of the California electricity sector, known as the "GHG Calculator." As part of this process, E3 issued white papers describing the modeling methodology, hosted conference calls to discuss specific technical issues with stakeholders and held a series of public workshops at the CPUC describing the modeling methodology, data inputs and results.[4] The CPUC and CEC also solicited multiple rounds of comments from stakeholders between January 2007 and June 2008, on topics related to the GHG docket, including the development and results of the GHG Calculator.

The final modeling results were presented to stakeholders in May 2008 in a public workshop and in PowerPoint format, along with the version 2.b of the GHG Calculator. In October 2008, the CPUC and CEC Commissioners adopted the "Final Opinion on Greenhouse Gas Regulatory Strategies" (CPUC D.08-10-037 / CEC Adoption Order 2008-10-16-1). The Joint Decision made recommendations to the California Air Resources Board ("CARB") on measures and strategies to reduce GHG emissions in the electricity and natural gas sectors. The Joint Decision summarized the GHG Calculator modeling approach and referenced the results of the GHG Calculator analysis.

The CPUC/CEC Joint Decision made recommendations to CARB regarding implementation of AB 32 in the electricity and natural gas sectors. CARB is charged with regulation and oversight of the state's emissions including greenhouse gas emissions. AB 32 requires that CARB adopt a scoping plan, "for achieving the

[4] The model, documentation and final results presentation are all available for download from the E3 website at: http://www.ethree.com/cpuc_ghg_model.html

maximum technologically feasible and cost-effective reductions in greenhouse gas emissions."[5] The AB 32 Scoping Plan was developed after consultation with stakeholders and input from other state agencies, and adopted by the CARB board in December 2008. The Scoping Plan includes an approach for the state to achieve GHG reductions through a combination of market-based compliance mechanisms, such as a "cap and trade" policy, as well as direct regulation, alternative compliance mechanisms and monetary and nonmonetary incentives.[6]

The CARB Scoping Plan envisions that 40% of the state's emission reductions will come from regulatory measures in the electricity sector. Proposed measures include increased energy efficiency, achievement of a 33% renewable portfolio standard by 2020, increased use of combined heat and power and 3,000 MW of rooftop solar photovoltaics ("PV") installations. Additional GHG emission reductions will come from regulatory measures in other sectors of the economy as well as a proposed regional cap and trade system.

Since the issue of the Joint Decision and the adoption of the CARB Scoping Plan, E3 has made some improvements to the GHG Calculator and changes to some of the data inputs to reflect current estimates of renewable energy costs. We do not believe that any of these changes would substantively alter the findings of the CPUC and CEC's ("Commissions") Joint Decision. The purpose of this report is to present the findings of the current, updated GHG Calculator in a clear and succinct way and to describe the modeling approach and key findings.

1.2 Purpose of this Analysis

Although California's climate change legislation does not set a specific greenhouse gas reduction target for the electricity sector, policymakers have nonetheless established aggressive GHG reduction policies for the state's electricity sector. These policies include goals surrounding renewable energy development, energy efficiency, distributed generation, demand response and others. Many of these policies are still

[5] California Global Warming Solutions Act of 2006, Assembly Bill 32 (2006).

[6] California Air Resources Board, "Climate Change Proposed Scoping Plan," 2008.

under development or were under consideration at the time the GHG Calculator was first being developed in 2007. Likewise, the provisions of AB 32 permitted the development of a cap and trade approach to reduce greenhouse gas emissions, but left the specifics of how and whether to implement the policy to the CARB.

There were several purposes for initiating the GHG Calculator modeling effort. The first was to consider the options, cost and rate impacts of implementing regulatory measures for reducing greenhouse gas emissions from the electricity sector. The second was to consider the options, cost and rate impacts on different utilities and groupings of utilities in California of implementing a cap and trade policy in California's electricity sector. Specifically, the purpose of this project was to:

1. Calculate the impact on California's electricity consumers of implementing AB 32, California's Global Warming Solutions Act of 2006.
2. Test the sensitivity of results to a number of different sources of uncertainty (gas prices, load growth, energy efficiency costs).
3. Test the sensitivity of results to different implementation approaches, including a cap and trade program as well as regulatory mandates.
4. Complete all of the analysis using a transparent and open public consultation process.

1.3 The GHG Calculator Key Findings

In order to answer the questions posed by the Commissions, the GHG Calculator analysis focused first on three key scenarios, and then on running sensitivity analyses on important variables in the analysis. These three scenarios contain different policy assumptions and result in different forecasts of greenhouse gas emissions levels and costs in 2020. These scenarios bracket the likely range of resource portfolio options in 2020 for the electricity sector. Each scenario is summarized below:

- **Natural Gas Only Case.** The Natural Gas Only Case assumes no new development of low-carbon resources beyond the 2008 level. Only new natural gas generation is used to meet load growth. There are no new energy efficiency, rooftop solar PV, or combined heat and power ("CHP") programs in this scenario. The characteristics of this scenario are similar to those for the electricity sector in CARB's "business-as-usual" case.[7]

- **<u>Reference Case.</u>** The Reference Case assumes that existing California policies (as of 2007) for the electricity sector (for example, AB 107 requiring a 20% RPS by 2010) are continued to 2020. In the Reference Case, it is assumed that 2007 state policy objectives are met for renewable generation, energy efficiency, demand response, rooftop PV, and CHP.

- **<u>Accelerated Policy Case.</u>** The Accelerated Policy Case assumes substantially more aggressive targets and incentives than those included in the Reference Case, and shows a corresponding increase in low-carbon resource development. The Accelerated Policy Case was developed prior to the CARB Scoping Plan and does not assume exactly the same electricity sector measures as the Scoping Plan.[8] However, many of the policies modeled in the Accelerated Policy Case, such as a 33% RPS by 2020, are similar in the CARB Scoping Plan document.

A key finding of the GHG Calculator modeling effort is that relatively high levels of greenhouse gas reductions can be achieved by the combination of approaches evaluated in the Accelerated Policy Case, at a relatively modest cost. The Accelerated Policy Case is expected to save over 30 million metric tonnes of CO_2e by 2020 compared to the Reference Case. This would represent a decrease in electricity sector emissions of 28% relative to the sector's average emissions of 109 MMT CO_2e between 2002 and 2004. Historical GHG emissions for California's electricity sector and the 2020 forecast of GHG emissions under each of the three key scenarios are represented in Figure 2 below.

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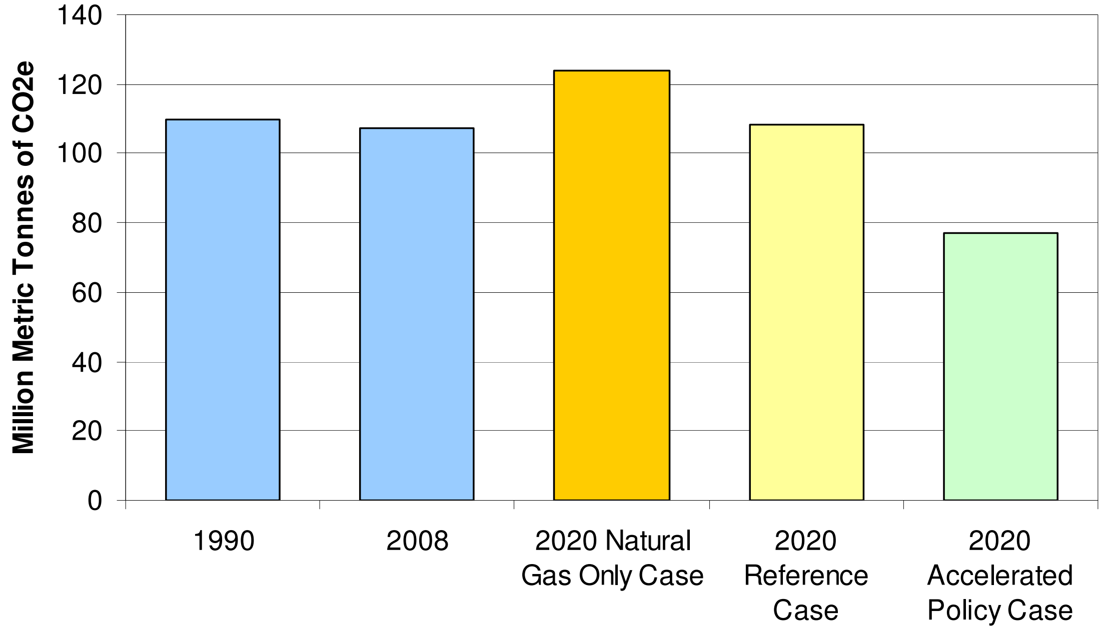
[7] There are three main differences between the Natural Gas Only Case and CARB's Business-as-Usual case: (1) CARB estimates a slightly higher rate of electricity load growth than that used by E3; (2) CARB assumes that no coal contracts expire between 2008 and 2020, whereas E3 assumes that California will not have responsibility for GHG emissions from coal contracts after their currently set expiration dates; and (3) CARB's Business-as-Usual case assumes a lower level of renewable energy in California than that included in the Natural Gas Only Case.

[8] Some of the differences between the Accelerated Policy Case and the Scoping Plan include the amount of electric energy efficiency achieved by 2020 and the level of GHG savings achieved with CHP generation.

Figure 2. Electricity Sector GHG Emissions Over Time and By Scenario



In terms of net utility costs, there are not large differences between the scenarios, and the differences fall within the ranges identified through sensitivity analysis (Section 4). However, the Natural Gas Only Case is the most expensive of the scenarios by a relatively small margin, while the Accelerated Policy Case is the least expensive. The net utility cost of the Accelerated Policy Case is approximately 0.6% lower than the Reference Case in 2020, and 2.5% lower than the Natural Gas Only Case in 2020 (See Figure 3 below). Reductions in electric demand due to energy efficiency and distributed generation offset the other more costly emission reduction measures, resulting in a relatively modest decrease in the net utility cost of providing electricity statewide in the Accelerated Policy Case.

The GHG Calculator also estimates direct customer costs. Customer costs are costs that are not paid through electricity rates but rather are invested directly by customers, such as the customer out-of-pocket costs associated with the purchase of a solar PV system, after receiving a California Solar Initiative rebate or incentive. The utility cost portion of that solar PV system includes the rebate offered by the utility for the system. An analysis of private customer costs is included in the GHG Calculator analysis for all of the policies that contain both a utility cost component and a customer cost component. These policies include support for rooftop solar PV, energy efficiency and CHP investments. The Natural Gas Only Case has no customer costs in 2020 because the scenario does not include any incremental energy efficiency, solar PV, or CHP programs. Customer costs are not estimated for 2008 (Figure 3).

A Note about Customer Bills and Utility Cost

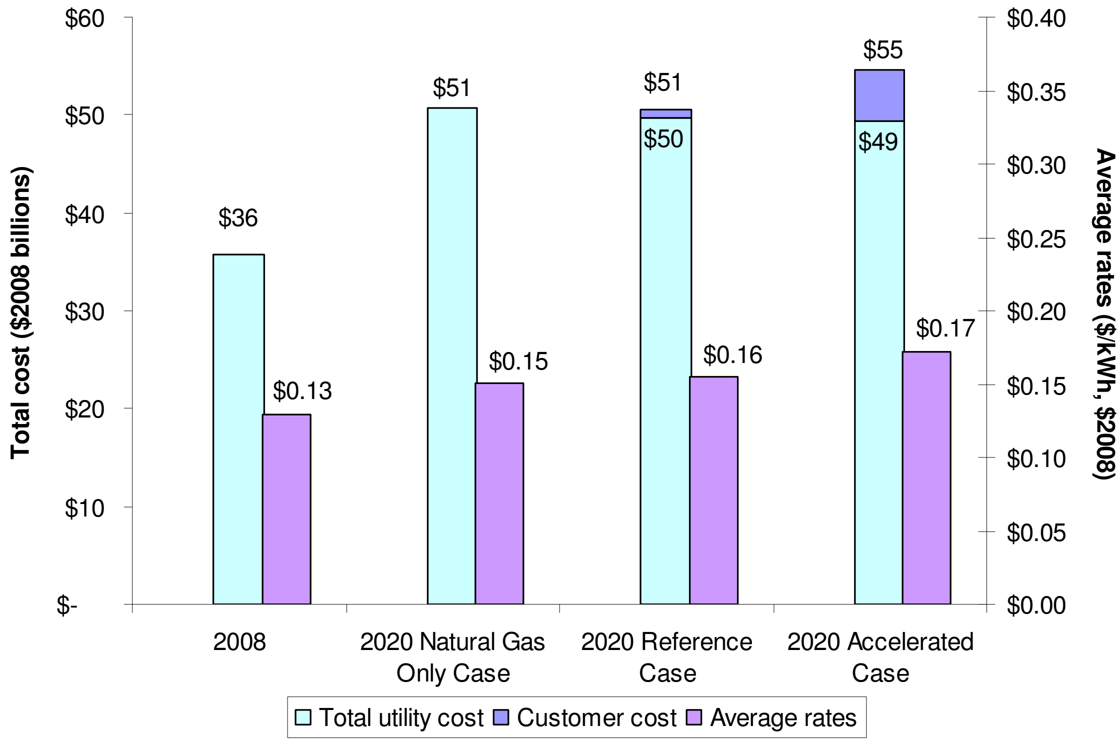
The potential cost impact of AB 32 on California's electricity consumers is measured as the change in average utility cost, also known as utility revenue requirement. This metric is roughly representative of impacts to average customer bills, once rates are adjusted through the rate-setting process. Utility cost is a measure of the electricity-related costs that must be recovered through electric bills to maintain a utility's regulated rate of return. Therefore, on average, higher utility costs will correlate with higher average electric bills, while lower utility costs will correlate with lower electric bills. This analysis does not undertake a customer bill impact analysis, given the complexities in the regulatory process to assign costs to different customer classes.

Another key finding of this analysis is that statewide average rates are likely to increase by 2020 relative to 2008, regardless of what greenhouse gas policy options are implemented. Statewide average rates are expected to increase 17% between 2008 and 2020 under the Natural Gas Only Case in real terms.[9] Under the Reference Case, whereby the state continues 2008 levels of energy efficiency and achieves a 20% RPS by

[9] All dollar values in this report are denominated in real 2008 dollars, unless otherwise specified.

2020, rates are projected to increase 20% relative to 2008 levels. In the Accelerated Policy Case, rates are projected to increase by 33% relative to 2008, and by 10% compared to the Reference Case in 2020.

Figure 3. Utility Costs, Customer Costs, and Average Rates in Three Key Scenarios, updated for v.3b



The analysis also considers the impacts of a California-wide, multi-sector cap and trade program on the state's electricity sector. Existing theoretical literature and empirical studies of cap and trade programs on sulfur-dioxide and nitrogen-oxide gases suggest that cap and trade programs could achieve emission controls at a lower total compliance cost than other approaches. However, given the ambitious GHG reduction goals laid out for the entire state of California under AB 32, this analysis suggests that complementary policies are likely necessary to achieve the GHG target, in addition to market-based mechanisms. We find that a California-only cap-and-trade system is likely to increase costs in the electricity sector without achieving meaningful additional GHG reductions, beyond the level of complementary policy reductions, unless one of the following, or a combination of the following, conditions occur:

- Carbon prices reach high levels (\$100/tonne CO_2e or more);
- Natural gas prices increase significantly (100% or more from the Reference Case assumption of \$7.85/MMBtu in 2020, in 2008 dollars);
- Technology innovation reduces the relative cost of low-carbon electricity resources compared to natural gas generation, or technology improves the performance of low-carbon technologies significantly;
- Lower-cost emission reduction opportunities are available from other sectors under the cap-and-trade program (though in this case the GHG reductions would come from those sectors and not the electricity sector. This condition would serve to reduce the cap and trade compliance costs to the electricity sector, but would not reduce emissions from the electricity sector).

All of the potential cap and trade policy options analyzed here result in higher costs and rates for the state's retail providers as a whole, regardless of which policy is pursued. This is because the GHG price is expected to increase the market clearing price for electricity, and these costs will be passed through to customers. If a GHG allowance auction is pursued, and no auction revenue is returned to utilities, the rate impacts are expected to be highest of all the policy options analyzed here.

The impacts of a cap and trade policy on California's electricity sector could have important distributional impacts to the state's retail providers, as well as to electricity producers and consumers. While some cap and trade policy choices (output-based or sales-based allocations) are beneficial to lower-carbon intensive retail providers, other policies are more beneficial to higher-carbon intensive retail providers (historic emissions-based allocations). In all cases, we find that retail providers that own low-carbon generation resources are better off under a cap and trade policy than are the retail providers that are more exposed to market purchases, due to higher expected wholesale electricity prices under a cap and trade policy.

1.4 Changes to GHG Calculator (Version 3b)

Since the CPUC/CEC Joint Opinion on Greenhouse Gas Regulatory Strategies was released, E3 has made a few changes and corrections to the GHG Calculator inputs and calculations (now reflected in Version 3c of the GHG Calculator). None of these changes substantially alter the findings of the Joint Decision. The impact of the changes from Version 3c is to slightly change CO_2 savings, the utility cost and total resource costs of combined heat and power (CHP) in the GHG Calculator. The changes to Version 3c are relatively minor and as a result are not reflected in this report. Rather, the changes to CHP are discussed in a separate Addendum, also available on the E3 website: www.ethree.com. This report only reflects the changes from Version 3b. The impact of the changes from Version 3b has been to slightly increase the estimated cost and rate impacts of the scenarios relative to version 2b of the Calculator.

The cost increase of these scenarios in the revised Version 3b of the GHG Calculator is largely due to the combined impact of four changes. These changes are described below:

- The renewable energy costs have been updated to reflect the most recent cost assumptions applied in the CPUC's 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results report, released in June 2009.[10] The report's renewable energy cost assumptions were primarily developed from the Renewable Energy Transmission Initiative (RETI).[11] The most significant change is to the solar thermal costs. In the revised GHG Calculator, the resulting all-in levelized cost of energy for solar thermal is $184/MWh, compared to the previous version of the GHG

[10] California Energy Commission, "33% Renewables Portfolio Standard Implementation Analysis: Preliminary Results," June 2009. The report and spreadsheet model are available to download at: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm.

[11] The Renewable Energy Transmission Initiative (RETI) is a joint, statewide effort to help identify the transmission projects in California to meet the state's renewable energy goals. RETI is overseen by a coordinating committee with representatives from the CPUC, CEC, California Independent System Operator and the Publicly-Owned Utilities. Information about RETI is available at: http://www.energy.ca.gov/reti/documents/index.html.

Calculator, which put the cost of solar thermal energy at \$153/MWh (in real 2008 dollars at the busbar, which excludes the cost of transmission).

- In the previous version of the GHG Calculator, Version 2.b, the utilities' revenue requirement calculation mistakenly excluded the cost of delivering the Reference Case level of renewable energy from the Tehachapi and Imperial resource zones. In Version 3 of the GHG Calculator, the costs of renewable resources included in the Reference Case were mistakenly double-counted in the Accelerated Policy Case, and received double savings credit in the Natural Gas Only Case. This mistake was discovered in late February 2010. As a result, this report has been re-released as Version 3b with these corrections, and a new version of the GHG Calculator has been released.
- In Version 2.b, the Natural Gas Only Case exclusively uses market purchases of electricity to meet incremental generation needs, above the amount of generation that currently existing generation capacity could provide in 2020. The revised version of the GHG Calculator now assumes that these incremental generation needs are met through the purchase of generation from new combined cycle natural gas and combustion turbine units, rather than from cheaper market purchases. This change slightly increases the cost of the Natural Gas Only Case.
- In Version 2.b, CHP generation that was supposed to be exported to the grid in the Accelerated Policy Case was being incorrectly counted as if it were behind-the-meter generation, reducing total retail sales. This error is corrected in Version 3 and 3b of the calculator, resulting in slightly higher retail sales in 2020 in the Accelerated Policy Case. As a result, the Accelerated Policy Case now contains 500 additional MW of renewable energy compared to the previous version of the Calculator, to ensure that this scenario achieves the 33% RPS requirement by 2020. This change slightly increases the cost of the Accelerated Policy Case.

Two additional changes to the GHG Calculator served to slightly decrease the costs of the 2020 resource scenarios:

- The cost of energy efficiency programs was overestimated in Version 2.b of the Calculator. Version 2.b of the GHG Calculator applied a 40% program administration cost to the energy efficiency ("EE") program costs. However, the EE cost estimates we were using already included the cost of program administration. This double-counting of EE program administration costs was corrected in Version 3 of the Calculator, slightly reducing the cost of energy efficiency in the Accelerated Policy Case. In addition, previously, EE customer costs were mistakenly double-counted in Figure 3 of this report. This is corrected in Version 3b.
- The 2008 estimate of San Diego Gas and Electric's ("SDG&E's") average retail rates has been reduced to $0.145/kWh from $0.18/kWh. The original rate estimate for SDG&E was based on the CEC's 2007 Integrated Energy Policy Report retail rate forecast. However, SDG&E pointed out in their comments that this estimate was too high.[12] As a result of lowering the 2008 rates for SDG&E to the level included in their CPUC filing, all of the revised 2020 scenarios show a lower SDG&E rate than the previous version of the model.

The final important change to the GHG Calculator affects the distribution of costs among the electric retail providers in the Natural Gas Only Case. The previous version of the GHG Calculator did not correctly account for renewable energy from the retail providers if a scenario was selected in which the renewable energy amount was *lower* in 2020 than a 20% RPS, the Reference Case assumption. As a result, in the previous version of the model, a retail provider could end up with less renewable energy in 2020 than they started with in 2008, creating problems for the cost accounting associated with renewable energy. The revised Version 3b of the GHG Calculator corrects this issue.

[12] The revised rate forecast is based on SDG&E's CPUC filing AL-1978-E, as described in their comments in the CPUC GHG proceeding R.06-04-009 on June 2, 2008, pg. 41, line 1251.

This change does not affect total statewide costs, but does change the distribution of costs among retail providers in the Natural Gas Only Case. For more information about the other, smaller changes to Version 3b of the GHG Calculator see Appendix B.

2 Methodology

2.1 The Two Model Approach

The GHG Calculator was developed by relying in part on the outputs of a more complex production simulation dispatch model, called PLEXOS. The goal of this "two model approach" was to strike a balance between maintaining transparency while preserving sufficient accuracy, by using the key outputs of a complex model to develop a simpler, transparent spreadsheet model. The production simulation dispatch model, PLEXOS, improves the accuracy and credibility of the modeling results, while the simpler spreadsheet model, the "GHG Calculator," facilitates increased public participation and transparency in the presentation of the final results. This two-model approach also allowed the modeling process to be completed within the relatively short timeframe specified by the Commissions, and helped the Commissions and public stakeholders to focus on the "key drivers" of the AB32 analysis.

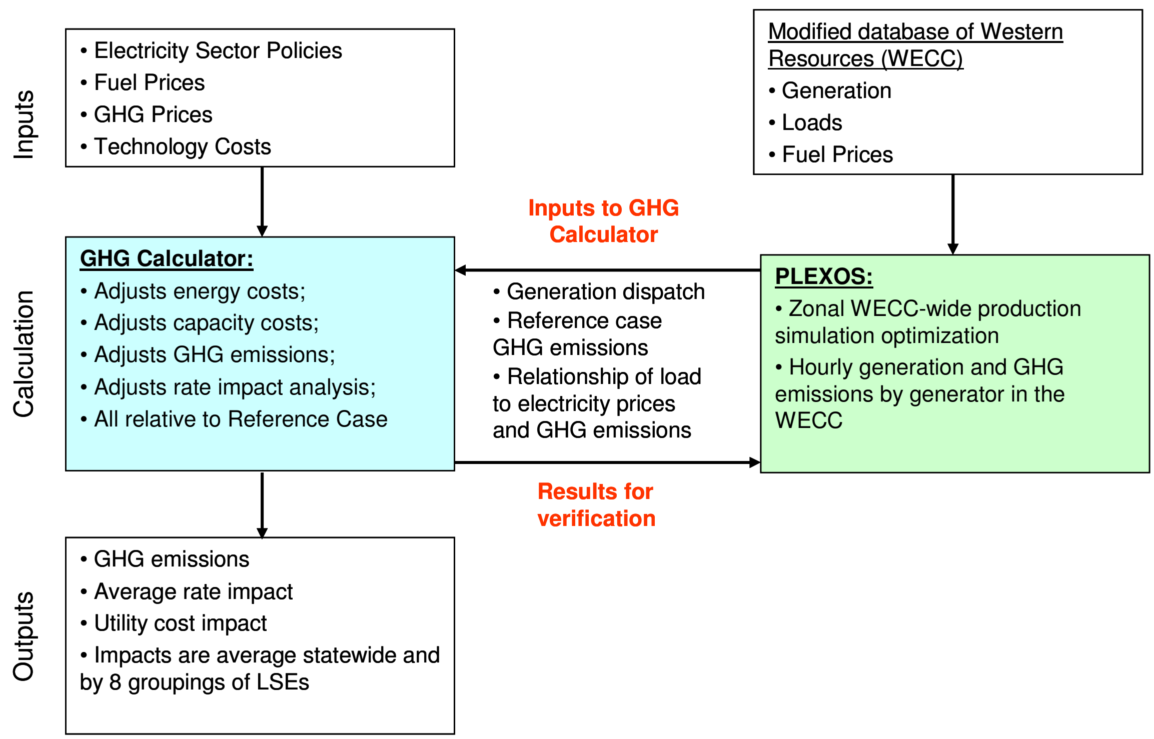
PLEXOS is an hourly dispatch model of the entire western portion of the U.S. grid, known as the Western Electricity Coordinating Council ("WECC"). The PLEXOS model applies advanced mixed integer programming as its core, co-optimization algorithm to simulate how each generator in the Western Interconnect grid would operate to meet load in a given year under specific transmission constraints on an hourly basis.[13] Inputs to the PLEXOS model include forecasts of loads and resources in 31 Western "zones."

The modeling process begins with forecasts of resources, loads and fuel prices which are fed into PLEXOS. These inputs generate a forecast of hourly, individual power plant output, power plant operational patterns and costs, and GHG emissions by plant. The hourly PLEXOS data is summarized into four time-periods: 1) summer high-load hours; 2) summer low-load hours; 3) winter high-load hours; and 4) winter low-load

[13] The PLEXOS model is based on the Ph.D. work of Glenn Drayton (G.R. Drayton. Coordinating Energy and Reserves in a Wholesale Electricity Market. University of Canterbury, New Zealand, 1997.)

hours.[14] These consolidated results are then used as an input for the GHG Calculator, which is used to calculate costs, rates and GHG emissions for a variety of different scenarios. The GHG Calculator allows users to quickly calculate the cost and GHG impact of variations in electricity policies, fuel prices and other key variables. This modeling process is shown in Figure 4 below.

Figure 4. Schematic Design of Two Model Approach

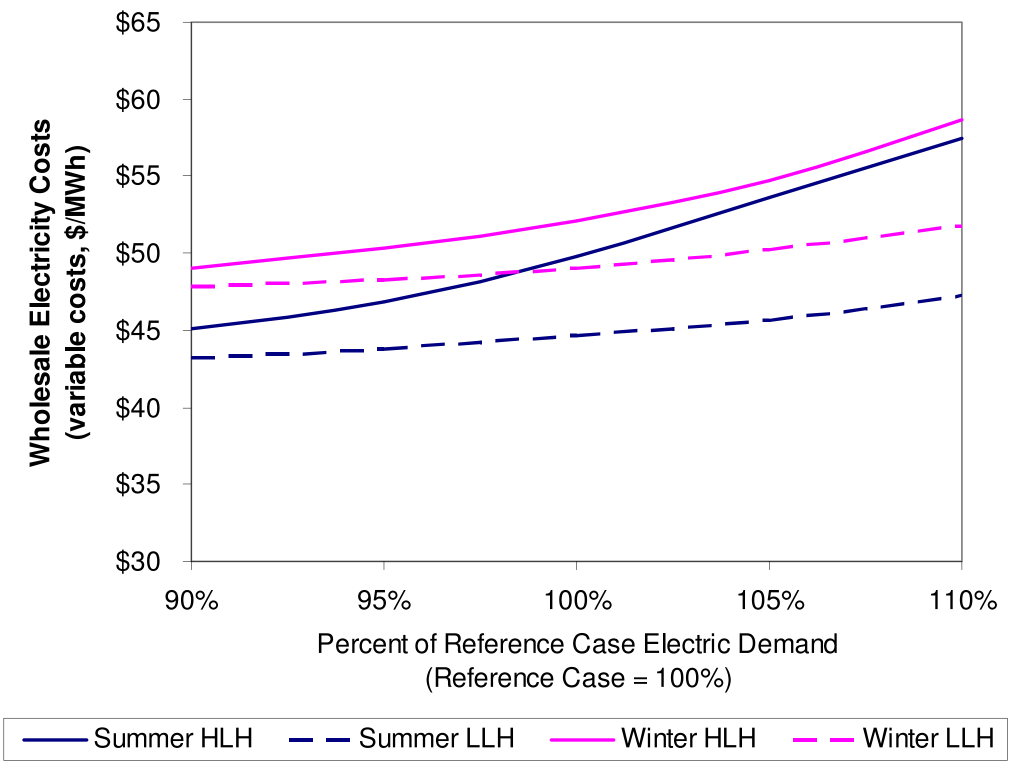


This production simulation dispatch model was also used to generate costs and GHG emissions estimates for the California 2008 case and for the 2020 "Reference Case," described above. Using the production simulation dispatch model for the development of the Reference Case ensured that this important case would be relatively accurate and credible. However, developing a case for use in the production simulation dispatch model is an expensive and time intensive process, and requires the use of

[14] Summer is defined as May to September. Winter is the rest. High Load Hours are defined as Monday through Saturday 7-22 hours (6x16). Low Load Hours (LLH) are the rest.

proprietary software and information. For this reason, the PLEXOS model was also run for a range of load levels higher and lower than the Reference Case. These results were then summarized into four parametric curves in the GHG Calculator spreadsheet, defined by the four time periods used in the model. In short, the GHG Calculator contains assumptions about the relationship between load levels, the market clearing price of electricity, and the marginal GHG emissions rate of generation, which are based on data from the PLEXOS model (Figure 5 shows the relationship between load and wholesale electricity costs).

Figure 5. Parameterized output from PLEXOS showing relationship between electric demand and variable electric cost in California in 2020, holding all else constant



Note: HLH = high load hours, also known as peak demand hours, LLH = low load hours, also known as off-peak hours

In the GHG Calculator, when the net load, or generation levels relative to load, are changed in a scenario, the parametric curves are used as an approximation of the market clearing prices and marginal CO_2 intensity of the new generation dispatch.

Because of the parametric curves, these impacts can be estimated without re-running the entire production simulation model. In this way, the GHG Calculator allows new scenarios and sensitivities to be calculated more rapidly, and in a more transparent way, than the production simulation dispatch model. In addition, we undertook a benchmarking exercise that verified that the GHG Calculator results were reasonably accurate when compared against the PLEXOS outputs. As a result, we concluded it was not necessary to re-run the PLEXOS model for each scenario that the Commissions analyzed.

2.2 Input variables

The approach of the GHG Calculator modeling effort is to create a publicly-available, non-proprietary tool which allows stakeholders and agency staff to create and run their own scenarios in the model – varying such fundamental parameters as the electricity load growth forecast, energy efficiency achievements and costs, as well as other supply and demand-side resource developments and costs between 2008 and 2020. The model also allows analysts to vary assumptions surrounding regulatory policies and/or cap and trade policy that could affect the electricity sector.

Since the GHG Calculator is a spreadsheet tool, nearly every input and calculation in the tool could, potentially, be changed. However, the model is designed to more easily allow certain resource choices to be manipulated. Some examples of California's policy goals which can be evaluated in the GHG Calculator include:

- ***Energy efficiency ("EE"):*** The GHG Calculator includes four choices for energy efficiency savings which can be selected from. These choices include a reference case, (the lowest EE achievement option), and a low goals, mid-goals and high-goals EE achievement option. These cases represent statewide levels of EE achievements. The mid-goals case is derived from the CPUC's energy efficiency goals for the three IOUs, adopted in July 2008, which includes savings of over 4,500 MW and 16,000 GWh between 2009 and 2020, the equivalent of nine power plants, which are then scaled-up in the GHG Calculator to a statewide level. [15]

- ***Demand response ("DR"):*** The GHG Calculator allows the percentage of peak demand reduced through demand response in 2020 to be modified in different scenarios. The state's first Energy Action Plan set a goal of reducing peak demand by 5 percent (between 1,500 and 2,000 MW) with price-responsive DR by 2007.[16] The state has not yet achieved this goal, but is still aggressively moving forward to increase levels of DR. In the model, demand response reduces the need for new peak generation capacity but does not save energy.

- ***California Solar Initiative ("CSI"):*** The GHG Calculator allows the user of the tool to select the amount of rooftop solar PV that is installed statewide by 2020. The million solar roofs initiative, passed under Senate Bill 1 in 2006, seeks to encourage the state to install 3,000 MW nameplate of rooftop solar PV by 2017.

- ***Combined heat and power ("CHP"):*** The GHG Calculator allows the user of the tool to select different levels and types of CHP that will be installed in California by 2020. Although the state did not have a specific policy to promote new CHP at the time of the modeling, after the release of Version 2.b of the GHG Calculator, the CARB Proposed Scoping Plan set a goal of reducing 6.7 million metric tons of CO_2 by 2020 through the use of new CHP units. CARB estimates this figure to represent approximately 4,000 MW of new installed CHP generation capacity.[17]

[15] CPUC Rulemaking 06-04-010, Decision 08-07-047, "Decision adopting interim energy efficiency savings goals for 2012 through 2020, and defining energy efficiency savings goals for 2009 through 2011," August 1, 2008, pg. 1.

[16] California Energy Action Plan, adopted 2003, pg. 5. Available at: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.

[17] California Air Resources Board, "Climate Change Proposed Scoping Plan," adopted October 2008.

- ***Renewables Portfolio Standard ("RPS"):*** The GHG Calculator allows users of the tool to adjust the level of renewable energy expected to be delivered to California by 2020. The tool allows users to choose which renewable resource zones across the West are likely to be developed to meet the state's RPS (e.g. in-state renewable energy from Imperial Valley or out-of-state wind from Wyoming). Currently, California law requires the state to meet 20% of retail sales from qualifying renewable energy by 2010, and the state's goal is to meet 33 percent of retail sales from qualifying renewable energy by 2020.[18]

In addition to these resource choices, the model allows users of the GHG Calculator to change the resource cost assumptions, as well as to evaluate various cap and trade policy options, and the effects of such changes on different groupings of retail providers. The cap and trade variables which can be input into the GHG Calculator include:

- The market clearing price for GHG emissions allowances between 2012 and 2020.
- The percentage of the GHG compliance obligation that may be met with GHG "offsets" of different types, as well as the market clearing price of different categories of offsets.[19]
- The method of allocating GHG allowances to electricity utilities, whether administratively allocated or auctioned.
- If administrative allocation is selected, the user may choose the percentage of GHG allowances that are administratively allocated on the basis of a generator's energy output or on the basis of its 2008 emissions level.

[18] The 33% RPS by 2020 goal was established by California Governor Schwarzenegger in Executive Order S-14-08 and in Executive Order S-21-09, and has been supported by the CEC and the CPUC in their joint final opinion on strategies to reduce greenhouse gas emissions and meet AB 32 goals (R.06-04-009/#07-OIIP-1), and by CARB in its 2008 Climate Change Proposed Scoping Plan.

[19] Offsets are credits for emissions reductions achieved outside of the capped sectors in a cap and trade policy.

- If GHG allowance auctioning is selected, the user may choose the amount of GHG allowance auction revenue that is returned to retail providers, and on what basis the revenue is returned (based on retail providers' sales or 2008 emissions level).

Although the model is designed to allow users of the GHG Calculator to change many of the key parameters, the model's basic assumptions reflect state policies in place as of 2008, to the extent possible. These basic assumptions may be changed, but remain constant in the key scenarios evaluated in this report. These assumptions include:

- Emissions performance standard for generation, requiring all new generation and long-term contracts for generation meet a GHG emissions standard that is less than 1,100 lbs CO_2/MWh. The emissions performance standard effectively places a moratorium on new coal-fired generation, or new long-term contracts with coal-fired generation, that does not include carbon capture and sequestration[20];
- The 1976 legislative ban on new, in-state nuclear generation[21];

There are a number of other key input variables which may also be changed in the GHG Calculator. This report does not describe all of the available levers built into the GHG Calculator, but instead focuses on the key results and findings of this modeling effort. The key drivers identified in this modeling effort, and the data sources used for the default assumptions in the Calculator, are summarized in Table 1 below. More information on data and assumptions is available in Appendix A.

[20] See California Senate Bill 1368, 2006 statutes.

[21] See California Public Resources Code Sections 25524.1 & 25524.2.

Table 1. Key Drivers and Data Sources

Key Driver	Data Source	Notes
Peak Demand and Energy Forecast	California Energy Commission, California Energy Demand 2008 – 2018 Staff Revised Forecast, November 2007	Retail providers were grouped into eight categories modeled in the GHG Calculator. The 2018 forecast was extrapolated to 2020 using a trend of the final years of the forecast.
Energy Efficiency Scenarios	For the POUs, Energy Efficiency Potential Studies (AB 2021 filings with the CEC) and for the IOUs, the 2008 Itron Report, "Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond" written for the Public Utilities Commission.[22]	Three energy efficiency scenarios were developed, modeled after the CPUC EE goals study. The IOU goals were scaled to cover a statewide EE view, including EE savings from the POUs and other retail providers in the state.
Renewable Energy Resource Potential	Best publicly available data as of 2007, mostly from the National Renewable Energy Laboratory (NREL).	Based on geographic survey data of wind-speeds, solar insolation, biomass availability, hydroelectric availability etc. These data were combined into regional renewable energy zones, and the cost of developing renewable energy in each zone was estimated.

[22] Energy efficiency technologies included in the GHG Calculator consist primarily of technologies currently receiving incentives from investor-owned utility programs. Other off-the-shelf technologies are not included, and CARB's Draft Scoping Plan Appendices suggest a number of additional measures that are not included in Itron's set of measures. There are also many other delivery methods for energy efficiency that will require further analysis and evaluation. The Itron Goals Update report can be accessed at: http://www.cpuc.ca.gov/NR/rdonlyres/D72B6523-FC10-4964-AFE3-A4B83009E8AB/0/GoalsUpdateReport.pdf

Key Driver	Data Source	Notes
Resource Costs (both conventional and renewable generation)	Renewable cost estimates reflect values used in the CPUC 33% RPS Implementation Analysis[23], Natural gas combined cycle cost based on Market Price Referent in 2008, other generation costs reflect best available estimates.	Renewable resource costs were updated in version 3 of the model to reflect CPUC 33% RPS Implementation Analysis data, which was based on data from the Renewable Energy Transmission Initiative (RETI).
Existing Power Plants, Transmission, Generator Dispatch and Cost	Western Electricity Coordinating Council (WECC) Transmission Expansion Planning and Policy Committee (TEPPC) 2017 build-out case.	TEPPC 2017 scenario was adjusted to meet forecast of 2020 loads in each WECC zone modeled. The database includes existing generation resources, transmission pathways and ratings, fossil generator heat-rates, renewable energy capacity factors, and hydroelectric hours of availability.
Fuel price forecast	Market trades of natural gas futures for 2020 (New York Mercantile Exchange, NYMEX)	Seams Steering Group of the Western Interconnect forecast for all fuels is scaled relative to the NYMEX futures markets for 2020 natural gas prices in March 2008.
CHP resource potential	CEC Assessment of California CHP Market Potential, Moderate Market Access scenario used for Accelerated Policy case.[24]	Split between large and small CHP set at 5 MW based on Self-generation incentive program (SGIP) criteria.

[23] CPUC, 2009. "33% Renewables Portfolio Standard Implementation Analysis Preliminary Results", available at: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

[24] California Energy Commission, Public Interest Energy Research, 2005. "Assessment of California CHP Market and Policy Options for Increased Penetration, prepared by the Electric Power Research Institute.

2.3 Representation of California Retail Providers

The model focuses on 2020 cost and rate impacts to California's electricity consumers and a set of eight retail providers, described in Table 2 below.

Table 2. Grouping of California Electric Retail Providers Modeled in GHG Calculator

Name	Description
1. PG&E	Pacific Gas and Electric, bundled load only
2. SCE	Southern California Edison, bundled load only
3. SDG&E	San Diego Gas and Electric, bundled load only
4. SMUD	Sacramento Municipal Utility District
5. LADWP	Los Angeles Department of Water and Power
6. 'Northern Other'	A grouping of all other municipal utilities, direct access service providers and other retail providers located in Northern California.
7. 'Southern Other'	A grouping of all other municipal utilities, direct access service providers and other retail providers located in Southern California.
8. California Water Agencies	Includes the Central Valley Project, the Metropolitan Water Department, and the California Department of Water Resources. The "Water Agencies" are modeled in less detail than the other retail providers.[25]

The GHG Calculator includes many data inputs and assumptions about each group of retail providers, including their ownership of power plants, electricity contracts and load growth, as well as information about existing average system rates and existing generation mixes, among other information. For example, in the first year modeled in the GHG Calculator, 2008, each of the eight retail providers has a different average rate level and a different average emissions intensity of electricity. These different 2008 starting points impact the relative costs to each retail provider of reducing GHG emissions

[25] The category of Water Agencies was created in order to allow the model to exclude this portion of the state's load from the requirements of the renewable portfolio standard, rooftop solar PV programs and other policies that are only applicable to the state's other retail electric providers.

through 2020. The details about these input assumptions are available in the GHG Calculator itself, as well as the supporting methodology description.

The GHG Calculator is designed to evaluate the high level impacts of greenhouse gas mitigation policies to the California electricity sector and to these eight groupings of retail providers. The GHG Calculator does not provide sufficiently disaggregated information to be used as a resource planning tool. For example, the GHG Calculator does not evaluate scenarios of individual generator retirements or re-powering which may occur over the next twelve years. Likewise, the model does not reflect individual utility resource plans or municipal policies.

Modeling these eight categories of retail providers provides important insights to how some GHG mitigation strategies may impact different regional groupings of California's electricity customers. However, the GHG Calculator does not analyze the impacts of specific policies on different customer classes, such as large versus small residential or industrial customers. Likewise, the GHG Calculator does not analyze impacts to generators, "energy deliverers" or the smaller retail providers grouped within the Northern Other, Southern Other and the Water Agencies categories.

2.4 Strengths and Limitations

One of the strengths of the GHG Calculator is that it is based on "bottom-up" assessments of resource costs and potential for greenhouse gas reductions. The model includes detailed cost and resource potential information about renewable energy technology types by location in various resource zones across the West, as well as different options for energy efficiency achievements, rooftop solar PV, demand response and CHP installations. Renewable resource potential data is based on the best publicly available data, as of 2007, from sources such as the National Renewable Energy Laboratory.[26] This detailed information ensures that the data in the GHG Calculator is calibrated to California's specific resource availability circumstances.

[26] The Renewable Energy Transmission Initiative (RETI) developed new renewable resource potential data subsequent to the initial GHG Calculator study. The revised version of the GHG Calculator (v3)

Another strength of the Calculator is that the cost assumptions are transparent, and are derived from publicly available sources. The cost assumptions for new resources can also be adjusted to perform sensitivity analysis. The baseline cost and technology performance assumptions reflect 2008 cost levels. The potential impacts of investment or policies on technology transformation or innovation are not included in the Reference Case, nor are they endogenously calculated in the model. Rather, assumptions about technology transformation and innovation are inputs which can be affected by changing the cost assumptions in the model.

The model's cost assumptions reflect physical costs, rather than market prices. For example, the market price of electricity is set at the variable cost of the marginal generating units. We do not assume that the marginal generating units are able to set the market price above their variable cost of operation. Likewise, the estimated cost of new generation reflects an assumed rate of return on investment that is just sufficient to sustain new investment. The model does not estimate the *price* at which a generation resource might be sold.

Likewise, the model does not consider potential market effects such as competitive bidding behavior, market power, behavior changes due to new market incentives or the potential for "leakage" or electricity market gaming under various cap and trade scenarios. This approach assumes no rent-taking in the electricity market for the marginal generator, although generation that is more efficient than the marginal units does earn revenue greater than its variable costs.

The cost-based assumption in the GHG Calculator may underestimate the cost of electricity in some time periods, while the assumption of no technology transformation may overestimate the cost of some types of generation. However, the Calculator's reliance on only publicly-available data and its "bottom-up," cost-based approach make the GHG Calculator assumptions transparent and verifiable. Overall, we think this approach strikes an appropriate balance regarding the treatment of uncertainty in cost estimates and creates a clear platform to start from for sensitivity and scenario analysis.

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incorporates revised renewable energy cost data based on the RETI cost information, but does not update the renewable resource potential data.

In addition, the GHG Calculator allows analysts to easily run and compare multiple scenarios. The approach does not constrain the analyst to produce "least cost" outcomes. Rather, the model is set up to analyze scenarios which are expected to occur, or which are desirable for policy reasons.

In the model's strengths, there also lie important limitations. First, it is worth emphasizing that the model does not attempt to simulate interactive effects between the electricity sector and other sectors of the economy. This limitation is especially pertinent to note in the context of analyzing cap and trade policies, where greenhouse gas abatement costs in other sectors of the economy may have important ramifications for the electricity sector's GHG abatement costs. Likewise, cross-sectoral emission reduction measures are not explicitly accounted for. For example, new electrification of end-uses, such as the adoption of plug-in hybrid electric vehicles (PHEVs) could increase GHG emissions in the electricity sector by increasing electricity demand, but could generate net GHG savings by offsetting emissions in the transportation sector. The GHG Calculator is designed to capture the GHG emissions effect of a scenario with higher electricity demand, but is not designed to capture the GHG savings from reduced gasoline use in the transportation sector.

In addition, the GHG Calculator does not dynamically solve for market effects, such as the interactions between carbon prices, natural gas prices, electricity demand, renewable energy development, etc. Put another way, the model does not optimize an objective function of prices and environmental considerations.

3 California Electricity Sector Scenarios in 2020

While the GHG Calculator allows users to create and analyze numerous scenarios of California's electricity sector in 2020, in this report we focus on three key scenarios which help to bookend the possible outcomes for the electricity sector:

1. ***The Natural Gas Only Case:*** represents a state of the world where current renewable energy and demand-side management policies are eliminated and replaced with a focus on using only natural gas generation to meet demand.
2. ***The Reference Case:*** represents a California future where current policies and trends continue through 2020. This includes a continuation of California's comparatively aggressive energy efficiency programs, a statewide 20% RPS that is met by 2010, and a continuation of the Energy Commission's 2007 IEPR projected rate of solar PV installations through 2020.
3. ***The Accelerated Policy Case****:* represents a California future where reductions of greenhouse gas emissions in the electricity sector becomes a strong priority through 2020. This case assumes that currently projected energy efficiency savings approximately double by 2020, that a statewide 33% RPS is met by 2020, and that the state installs 3,000 MW of rooftop solar PV by 2020 as a result of the California Solar Initiative (CSI). The Accelerated Policy Case also has over 4,000 MW of new CHP being installed between 2008 and 2020.

Section 3 of this report describes the statewide impacts on greenhouse gas emissions, costs and rates of these three scenarios, and Section 5 describes the impacts to individual retail providers of these scenarios. The key assumptions applied in each of these three scenarios are described in the table below. Other than the variables outlined in Table 3, all other input assumptions, such as natural gas prices, are held constant between each scenario.

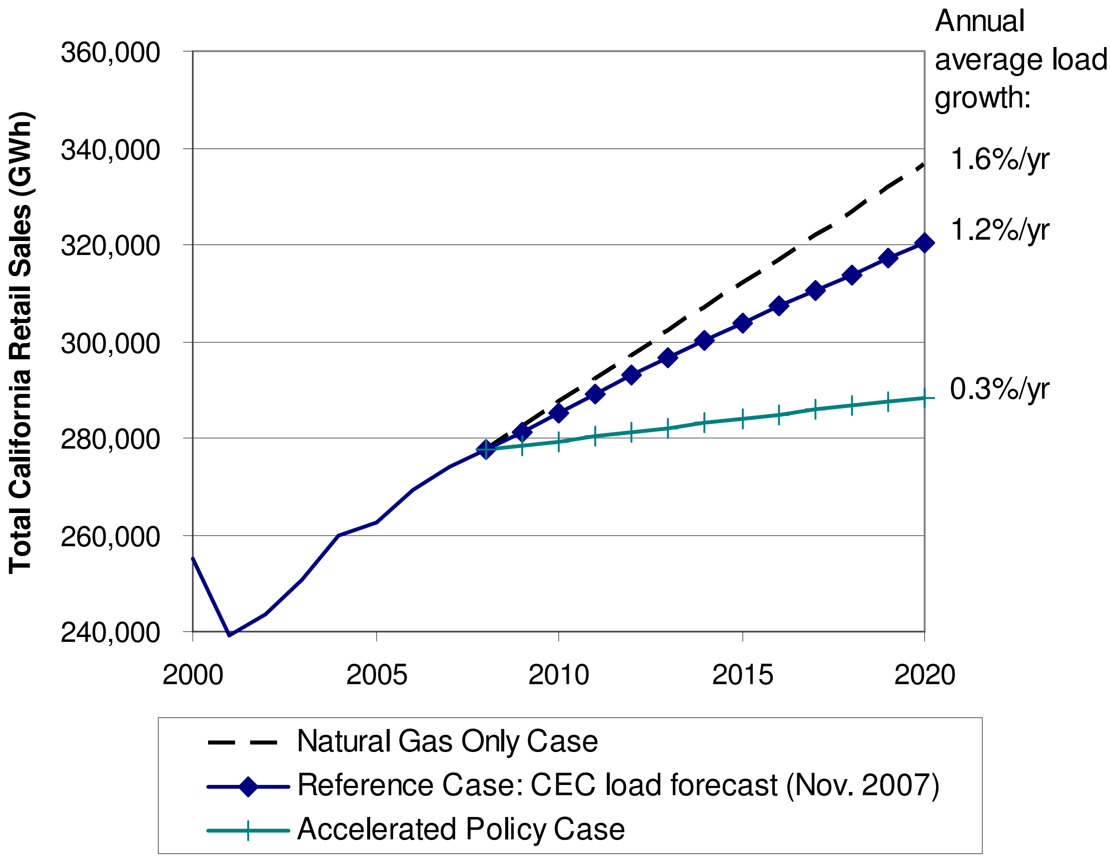
Table 3. 2020 Resource Portfolios for Three Key Scenarios

Inputs	Natural Gas Only Case	Reference Case	Accelerated Policy Case
Energy Efficiency (EE)	No additional EE after 2008 16,450 GWh added to CEC load forecast	CEC load forecast* Assume 16,450 GWh EE embedded in forecast	'High goals' EE scenario Based on CPUC Goals Update Study & POU AB 2021 filings = 36,559 GWh, including embedded EE in forecast
Rooftop solar PV	2008 rooftop PV only	CEC load forecast* Assume 847 MW nameplate of rooftop PV	3,000 MW nameplate of rooftop PV installed
Demand Response (DR)	Existing DR only	5% peak demand reduction	5% peak demand reduction
Combined heat and power (CHP)	CEC load forecast*	CEC load forecast*	1,574 MW nameplate small CHP (<5 MW) 2,804 MW nameplate larger CHP (>5 MW)
Renewable Energy	2008 renewable energy and 1,000 MW of Tehachapi developed	20% RPS by 2010 (6,733 MW)	33% RPS by 2020 (13,044 MW)

* California Energy Commission, "California Energy Demand 2008 – 2018 Staff Revised Forecast," November 2007, CEC-200-2007-015-SF2.

Figure 6 below represents the impact on retail sales of the demand-side resources applied in these three scenarios. The Natural Gas Only Case, which has no energy efficiency achievements beyond 2008, shows an increase in annual average load growth from 1.2 percent per year to 1.6 percent per year. The Accelerated Policy Case achieves the lowest level of load growth at 0.3 percent per year. This low level of growth is mostly due to the achievement of the "high EE goals" and a large increase in CHP generation in the Accelerated Policy Case.

Figure 6. California Retail Sales Forecast Under Three Scenarios



3.1 *Electricity Sector Greenhouse Gas Emissions*

The Reference Case results in a greenhouse gas emissions trajectory from 2008 to 2020 that is approximately flat, at 108 million metric tons of carbon dioxide equivalent (MMT CO_2e) by 2020. The Accelerated Policy Case results in an emissions level of 77 MMT CO_2e, or 29% below the Reference Case and approximately 30% below the electricity sector's 1990 emissions level. The Natural Gas Only Case results in higher greenhouse gas emissions, at 124 MMT CO_2e, a level 15% higher than the Reference Case.

Figure 7 below deconstructs the greenhouse gas emissions savings from these three scenarios into their components, illustrating the relative GHG savings obtained from each resource when transitioning from the high emissions Natural Gas Only Case to the Reference Case, and from the Reference Case to the low emissions Accelerated Policy Case.

The largest "wedges," or sources of GHG savings, are from energy efficiency savings and renewable energy. In achieving the Accelerated Policy Case, combined heat and power and solar PV play a more minor role. Table 4 below also shows the sources of GHG savings in the renewable energy category by technology type. In California, geothermal, solar thermal and wind are expected to be the largest sources of renewable energy available to meet a 33% RPS by 2020.

Figure 7. Source of GHG Savings by Resource and Technology Type, 2008 – 2020

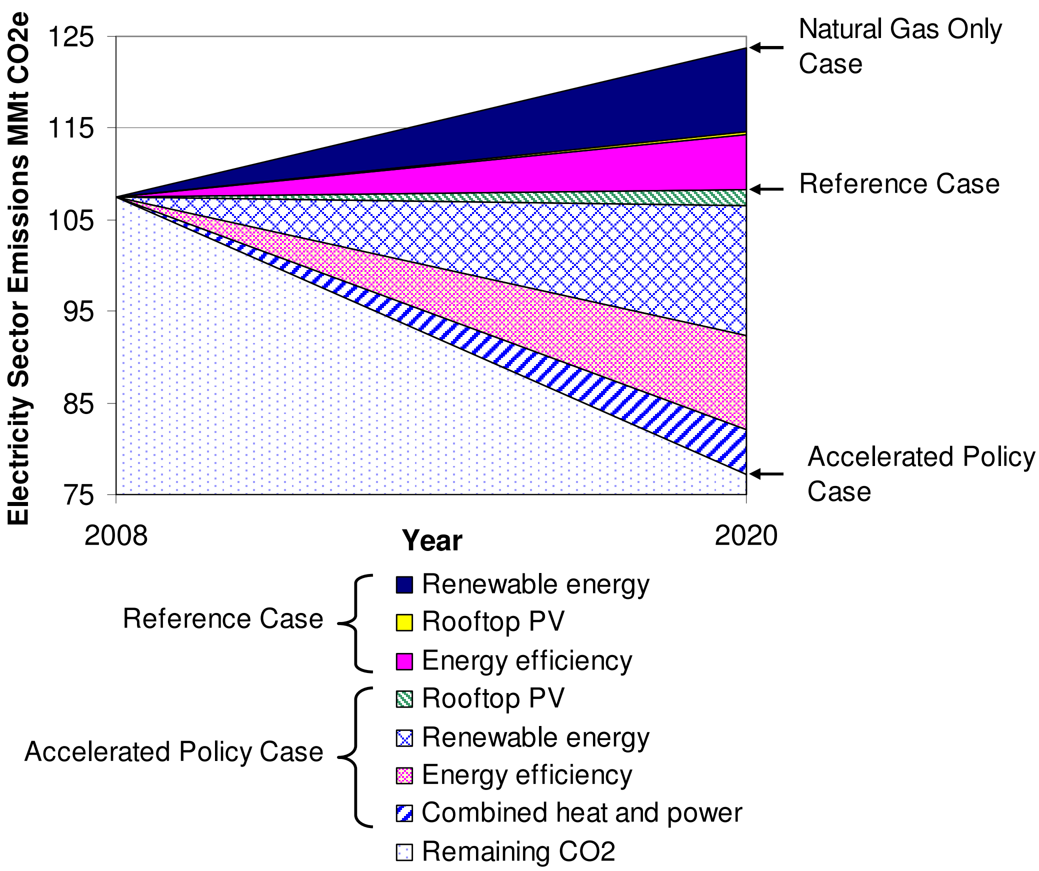


Table 4. 2020 GHG Reductions in Reference Case and Accelerated Policy Case

Low-carbon Resource	**Reference Case GHG Emissions Reductions Compared to Natural Gas Only Case (MMT CO_2e)**	**Accelerated Policy Case GHG Emissions Reductions Compared to Reference Case (MMT CO_2e)**
Energy Efficiency	**6.0**	**10.2**
Rooftop Photovoltaics	**0.4**	**1.7**
CHP	-	**4.9**
Electricity used on-site	-	*2.1*
Electricity delivered to grid	-	*2.8*
Renewable Generation	**9.1**	**14.2**
Biomass	-	*2.2*
Biogas	-	*1.1*
Wind	3.9	*3.3*
Geothermal	3.6	*3.9*
Solar Thermal	1.6	*3.7*
TOTAL	***15.5***	***30.1***

3.2 Emission Reduction Measure Costs

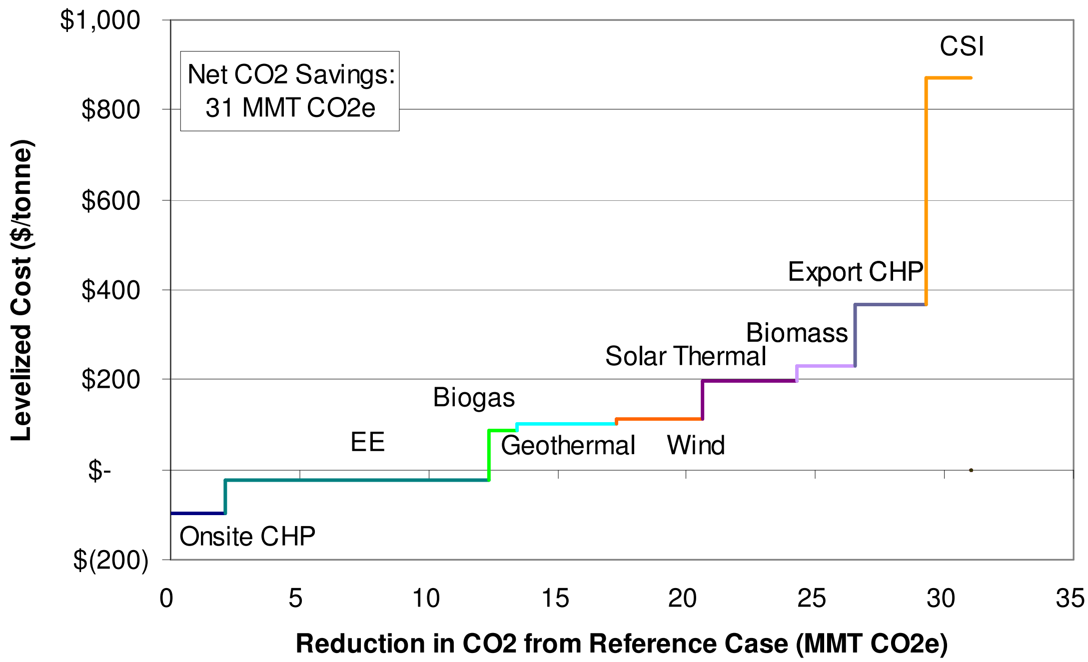
While the table above provides a useful breakdown of the emission reduction measures by program and technology type, a deeper understanding of the costs of each of these options is necessary. There are several ways to value the cost of emission reduction measures, including from a customer cost perspective, a utility cost perspective and a total resource cost perspective (which includes both customer and utility costs).

The figures below show two different greenhouse gas abatement supply curves for the same portfolio of measures in the Accelerated Policy Case compared to the Reference Case portfolio. Figure 8 shows the Accelerated Policy Case resource portfolio from the total resource cost perspective, including both customer and utility costs. Figure 9 shows the Accelerated Policy Case portfolio from a utility cost perspective, excluding the portion of measure costs borne by the customer.

The total resource cost perspective supply curve shows that on-site CHP, biogas and energy efficiency are by far the cheapest measures available in the electricity sector, when all electricity sector costs are considered.[27] The 'High EE goals' represented in the Accelerated Policy Case below includes high levels of energy efficiency mandates such as the "Huffman lighting bill" (AB 1109), Title 24 and Title 20 standards, and increased achievements from California's "Big and Bold Energy Efficiency Strategies." Assuming that rooftop solar PV costs remain at their current levels and do not undergo a dramatic cost reduction due to market transformation, CSI installations will come at the highest net cost, on a dollar per tonne of CO_2 saved basis. Note that in Version 3b, the cost per tonne of the demand-side measures have decreased slightly from the Version 3 results. This is because Version 3b now includes the transmission and distribution savings of demand-side measures (energy efficiency, California Solar Initiative (CSI) and on-site CHP) in the calculation.

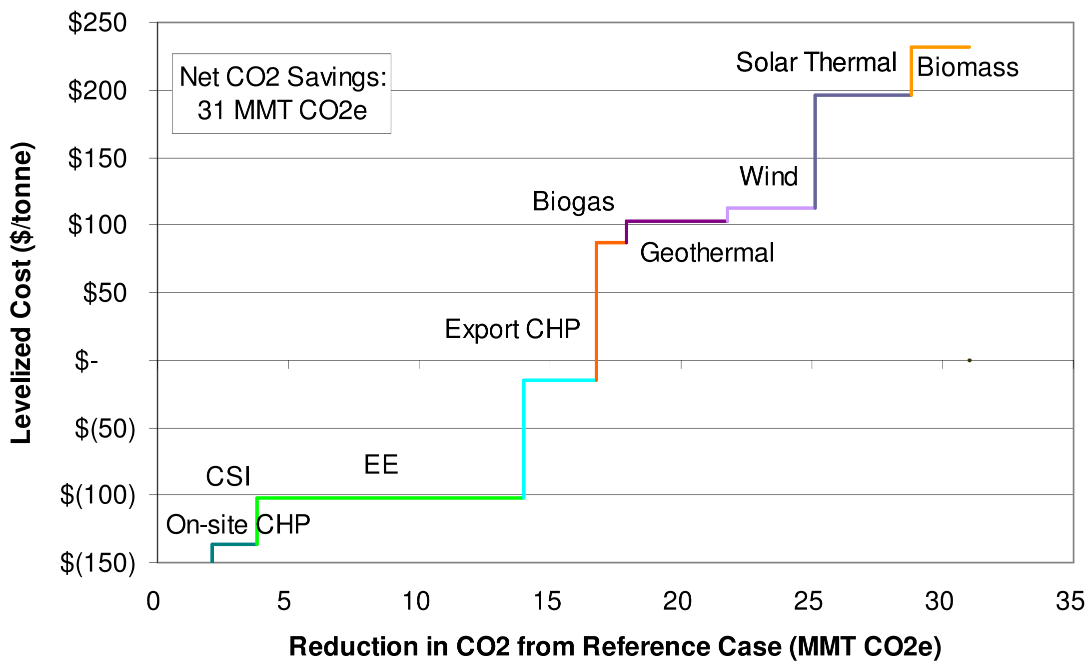
[27] CHP costs and benefits vary depending on the type of technology and application. As a result the CHP $/tonne shown in Figures 8 and 9 should be interpreted as indicative but not fully representative of all types of CHP in California.

Figure 8. Total Resource Cost Perspective of Accelerated Policy Case GHG Abatement Supply Curve Incremental to Reference Case, updated for v.3b



The utility cost perspective supply curve looks different than the total resource cost supply curve because the customer costs for combined heat and power, energy efficiency and rooftop solar PV are not included in the utility cost supply curve. Onsite CHP and solar PV provide illustrative examples. Since nearly all costs for these resources are incurred by the customer, but the carbon savings of rooftop PV installation and the electric portion of CHP CO_2 savings are credited to the electricity sector, on-site CHP and CSI appear extremely cost-effective from a utility cost perspective. There is also a significant customer cost component to the energy efficiency (EE) savings measures. This is why the "High energy efficiency goals" achieved in the Accelerated Policy Case come at a savings of $102/tonne CO_2e from a utility cost perspective compared to a cost of $24/tonne CO_2e from a total resource cost perspective.

Figure 9. Utility Cost Perspective GHG Abatement Supply Curve, updated for v.3b



The table below shows the cost per tonne of carbon reduced in the Accelerated Policy Case compared to the Reference Case for energy efficiency, renewable energy, the CSI program and CHP. Overall, the Accelerated Policy Case saves over 30 million metric tonnes of greenhouse gasses compared to the Reference Case. These CO_2e savings come at an average utility savings of $5 per tonne of CO_2e and an average total resource cost of $134 per tonne of CO_2e relative to the Reference Case.

Table 5. Carbon Saved per Measure and Cost per Metric Tonne of CO_2e Saved in the Accelerated Policy Case Compared to the Reference Case ($/tonne CO_2e), updated for v.3b

	GHG Savings (MMt CO2e)	Utility Cost ($/tonne)	Consumer Cost ($/tonne)	Total Resource Cost ($/tonne)
Energy Efficiency	10	-$102	$79	-$23
Renewables	14	$148	$0	$148
CSI	2	-$137	$1,004	$867
CHP	5	-$203	$370	$166
Total / Weighted Average for Costs	**31**	**-$5**	**$139**	**$134**

From a utility cost perspective, renewable energy is the most expensive resource, reaching an average cost of $148 per tonne of CO_2e saved. Utility scale renewable energy does not have a direct customer cost component, which is why the customer cost of renewable energy is zero. Energy efficiency is the most cost effective emission reduction measure from a customer cost perspective as well as from a total resource cost perspective. Not only is energy efficiency a low cost resource with the potential for significant carbon savings, energy efficiency also reduces load, and thus makes it easier to attain higher renewable energy penetration as a percentage of retail sales, required by the state's Renewable Portfolio Standard.

Calculating the $/Tonne in the GHG Abatement Supply Curves:

The supply curves shown above are calculated using the following approach for each measure:

$$\frac{\textbf{(Utility cost + Customer cost* - Energy cost - Capacity cost – T\&D cost)}}{\textbf{CO2 savings}}$$

Definition of terms:

Utility cost: Change in utility revenue requirement relative to the Reference case due to a given measure (i.e. EE program cost)

***Customer cost**: This term is only applied in the total resource cost supply curve; defined as the portion of the measure cost paid by the customer, rather than the utility.

Energy cost: Change in the cost of energy procurement relative to the Reference case, based on the wholesale, time-of-use price of electricity in the selected scenario (the electricity price varies with total demand).

Capacity cost: Change in the cost of meeting peak capacity requirements relative to the Reference case, based on capacity savings from change in energy use and cost of a natural gas combustion turbine.

T&D cost: Change in the utility cost of providing transmission and distribution (T&D) services relative to the Reference case. Demand-side measures reduce load, so can result in T&D savings.

3.3 Average Statewide Electricity Cost and Rate Impacts

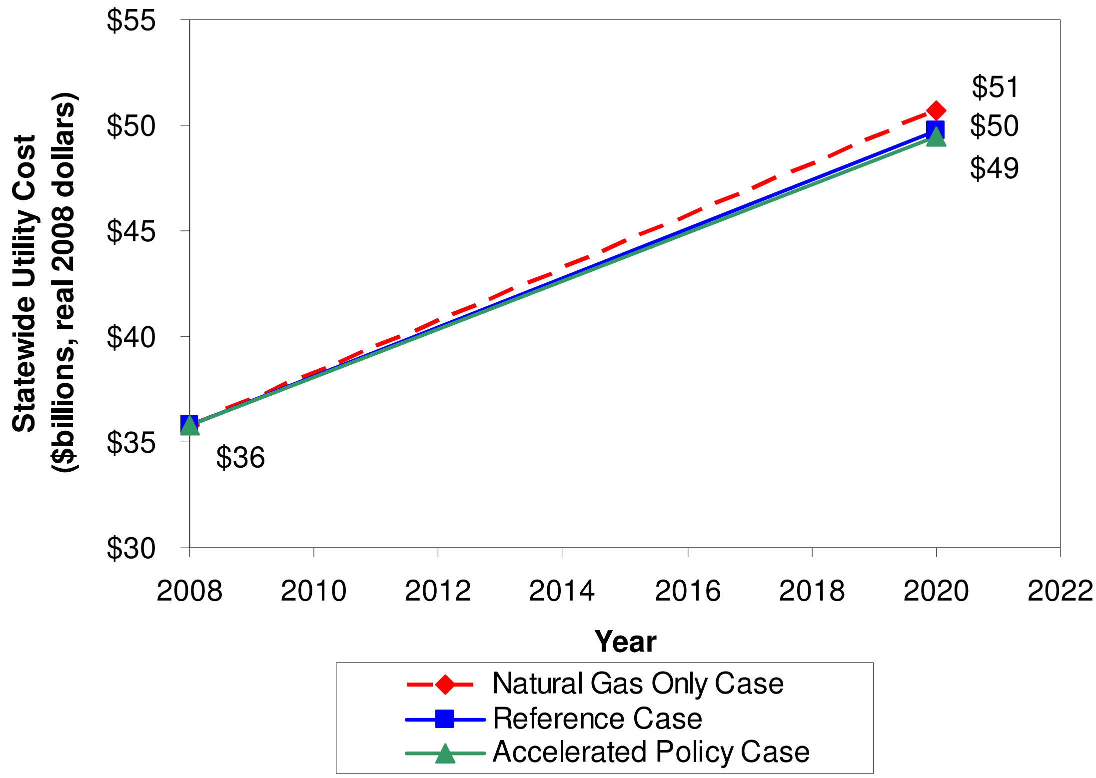
The Natural Gas Only Case, Reference Case and Accelerated Policy Case each result in different forecasts of average utility costs and average electricity rate impacts in 2020. The cost and rate impacts of each scenario are represented in Figure 10 and Figure 11 below.

Utility costs are driven by electricity demand as well as resource procurement costs and other fixed costs such as transmission and distribution costs. Expenditures on energy efficiency programs and other cost-effective demand-side resources tend to reduce utility costs, because these programs reduce electric demand and so avoid costs associated with procuring and delivering electricity to customers.

Utility cost, also known as utility revenue requirement, reflects, but is not a direct predictor of average customer bills. In general, when the utility revenue requirement goes up, average customer bills go up, and when utility revenue requirement falls, average customer bills fall. However, a full customer bill analysis is a complex undertaking and is not in the scope of the report. Customer bills are reflective of utility revenue requirements as well as population growth, electricity consumption per customer, and rate structures by customer class. For example, Assembly Bill (AB)1X freezes lower tier rates at the February 2001 level. Absent a legislative change, electricity rates for consumers with low usage of electricity who are subject to AB 1X will not change under any of these scenarios.

In all scenarios, utility costs are forecast to increase, in real terms, between 2008 and 2020. The Reference Case statewide utility costs are forecast to increase from $36 billion in 2008 to $50 billion in 2020, an increase of approximately 3% per year in real terms. In the Accelerated Policy Case, high levels of energy efficiency and CHP mitigate the higher costs of other emissions abatement measures such as renewable energy. This is why the Accelerated Policy Case costs about 0.6% less than the Reference Case; in the absence of the demand side measures, the Accelerated Policy Case would be much costlier than the Reference Case. The Natural Gas Only Case, with no additional demand-side resources and no additional renewable energy or other emission abatement measures beyond 2008, shows 2% higher costs than the Reference Case. However, overall, the costs of each of the three scenarios evaluated are relatively close.

Figure 10. Forecast of Statewide Utility Costs in 2008 and 2020, updated for v.3b

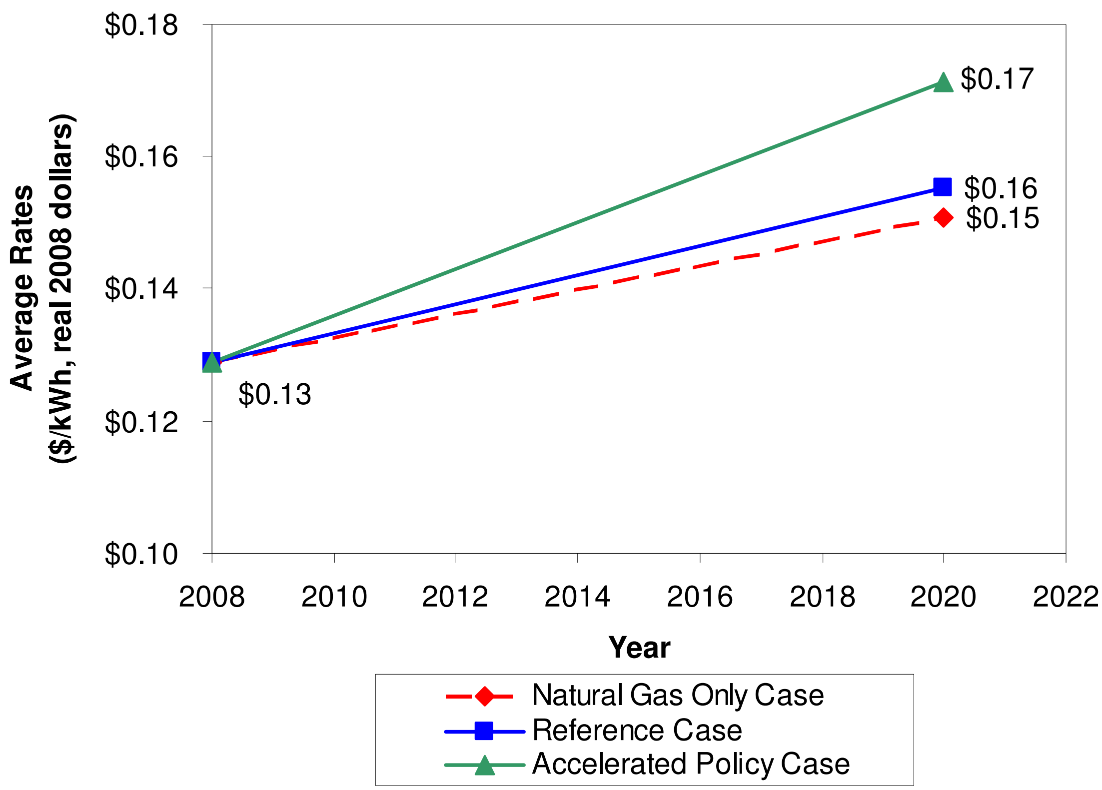


Just like utility cost, average electricity rates are expected to increase between 2008 and 2020, regardless of what policy is pursued, due to increasing capital costs of new generation. Figure 11 shows that statewide, total system average rates are expected to increase by 20% from 2008 to 2020 in the Reference Case, from approximately \$0.13/kWh in 2008 to \$0.16/kWh in 2020. Unless otherwise noted, all costs and rates in the report are in real dollars, which exclude the impact of inflation. If we were to include the impact of inflation, and assume an inflation rate of 2.5 percent per year, the nominal rate impact would be 62 percent between 2008 and 2020, or about a 5 percent per year nominal rate increase.

The Accelerated Policy Case shows the highest rate impact due to the combination of lower net load growth through high energy efficiency, and hence a smaller rate-base over which to spread cost increases, as well as higher resource procurement costs. This results in an additional 10% real rate increase over the Reference Case rates, to $0.17/kWh in 2020.

The Natural Gas Only Case has the highest load growth of the three scenarios, which is met through the procurement of natural gas combined cycle units. This means the Natural Case Only Case has both lower resource costs as well as a larger rate base, resulting in a slightly lower rate impact compared to the Reference Case, with statewide average rates forecast at $0.15/kWh in 2020.

Figure 11. Forecast of Statewide Average Rate Impact in 2020, updated for v.3b



While it is useful to forecast the average cost and rate impacts for the three scenarios to illustrate the overall impacts of GHG reduction policies in the electricity sector and to California's electricity consumers in aggregate, it is important to keep in mind that statewide average cost and rate impacts can be misleading if taken out of context. Individual customer rate impacts will vary substantially by tier, customer class and by retail provider.

4 Sensitivity Analysis

The GHG Calculator allows users to test different values for a number of key variables, including load growth forecasts, levels of energy efficiency achievements and 2020 natural gas price forecasts, among other variables. The sensitivity analysis results for variations in these three variables are shown below.

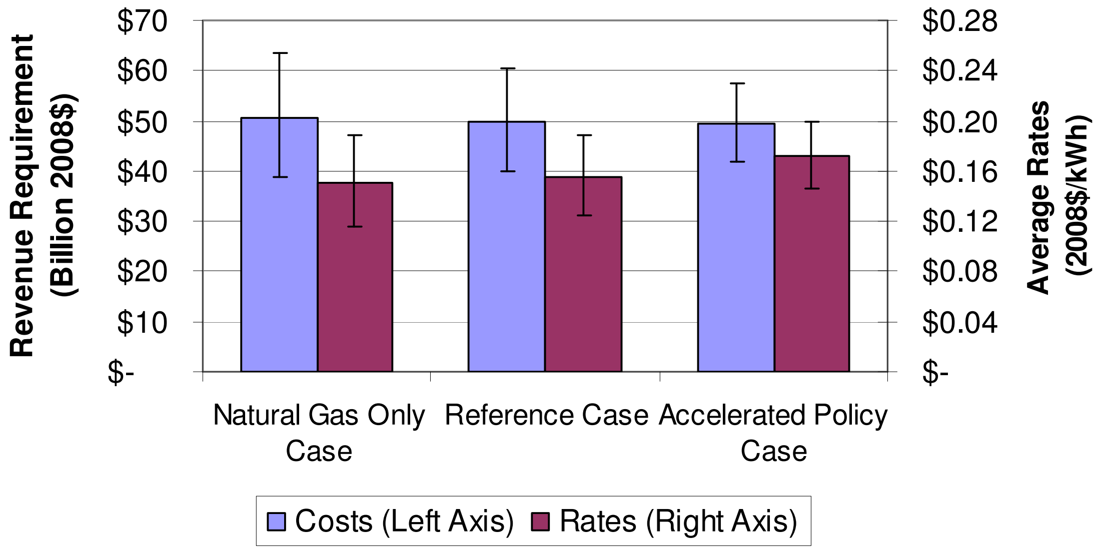
4.1 Natural Gas Price

Natural gas prices are notoriously volatile. For example, when this project began in 2007, gas prices stood at about $8 per million Btu (MMBtu). Natural gas prices increased to around $12/MMBtu in the summer 2008 and as of the writing of this report in September 2009, natural gas prices stood close to $3/MMBtu. Natural gas prices have a large impact on the cost of delivering electricity to Californians, because currently a large share of the state's electricity supply is based on natural gas fired power plants, and these power plants tend to set the wholesale market price of electricity. Finally, the calculation of the net cost of an emission reduction measure is intimately tied to the cost of the avoided natural gas that the emission reduction measure saved.

For these reasons, the natural gas price sensitivity is perhaps one of the most important sensitivities to test in this analysis. The baseline natural gas price in all scenarios is $7.85/MMBtu in 2020, in 2008 dollars. The high natural gas price sensitivity is set at $14/MMBtu in 2020, in 2008 dollars, and the low natural gas price sensitivity is set at $2/MMBtu in 2020, in 2008 dollars. This range of natural gas prices seeks to represent a very broad range of possible future gas prices, and as a result this sensitivity creates the widest range in outcomes out of all of the sensitivity ranges tested here.

Note that this analysis does not include an estimate of the price elasticity of demand with respect to natural gas prices. As a result, we do not estimate the impact of this wide range of natural gas prices on GHG emissions.

Figure 12. Sensitivity Analysis of Natural Gas Prices on 2020 Statewide Revenue Requirement and Average Rates by Scenario (low error bars represent $2/MMBtu natural gas prices and high error bars represent $14/MMBtu natural gas prices in 2020) , updated for v.3b



4.2 Energy Efficiency Achievements

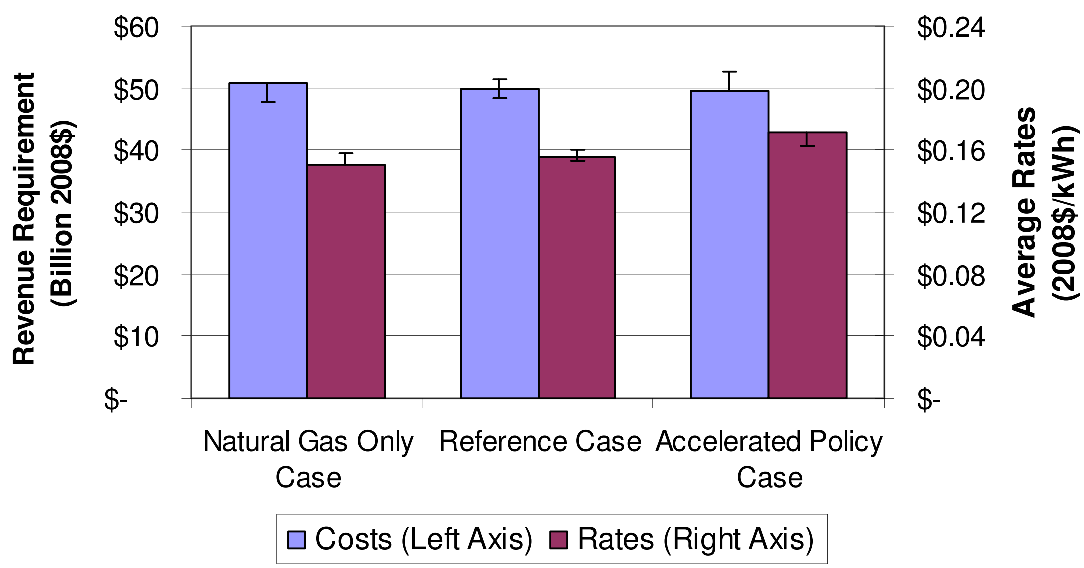
Energy efficiency is an important source of potential GHG savings in California's electricity sector, however, the future levels of energy efficiency achievements in the state remain highly uncertain. To address this uncertainty, we perform a sensitivity test on the level of energy efficiency savings achieved in each scenario. Figure 13 shows the impacts of higher and lower levels of energy efficiency savings on statewide revenue requirement and average rates in 2020.

In the Natural Gas Only case, the baseline level of energy efficiency is zero energy efficiency beyond 2008. For this sensitivity, we increase the level of energy efficiency to reach the "High Goals EE" scenario. This higher level of energy efficiency decreases the expected 2020 statewide utility revenue requirement, because the energy efficiency is cost-effective. Likewise, higher levels of energy efficiency slightly increase expected 2020 statewide average rates.

In the Accelerated Policy Case, the baseline level of energy efficiency is the "High Goals EE" scenario. For this sensitivity, we decrease the level of energy efficiency to the same level assumed in the Natural Gas Only case, zero energy efficiency beyond 2008. This sensitivity increases the 2020 expected statewide utility revenue requirement, and decreases expected average electricity rates in the Natural Gas Only Case.

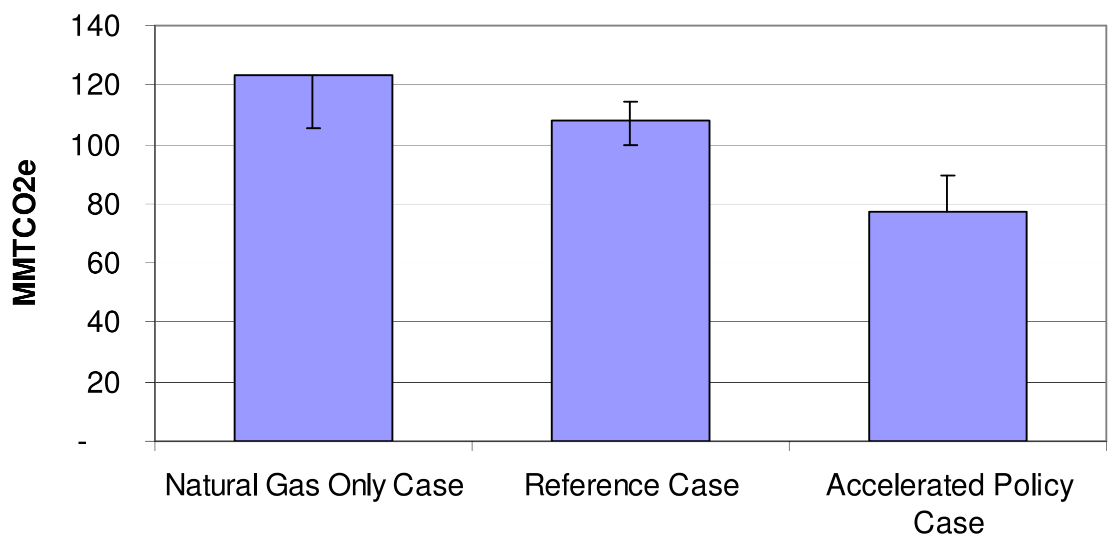
For the Reference case, the baseline level of energy efficiency is the "Reference case" level of EE. The Reference case level of EE is approximately equal to the amount of energy efficiency that E3 estimated was embedded in the 2007 California Energy Commission electricity demand forecast, or about 16,000 GWh of EE by 2020. For this sensitivity we both increased and decreased the level of EE achievements, equivalent to the "High Goals EE" case and the "no EE" case. The results of this sensitivity analysis are shown in Figure 13.

Figure 13. Sensitivity Analysis of Energy Efficiency Achievements on 2020 Statewide Revenue Requirement and Average Rates by Scenario (error bars represent high EE goals and no EE increment achievements, where applicable), updated for v.3b



Higher levels of energy efficiency savings result in lower levels of GHG emissions and vice-versa. The impact of the energy efficiency sensitivity on GHG emissions is shown in Figure 14.

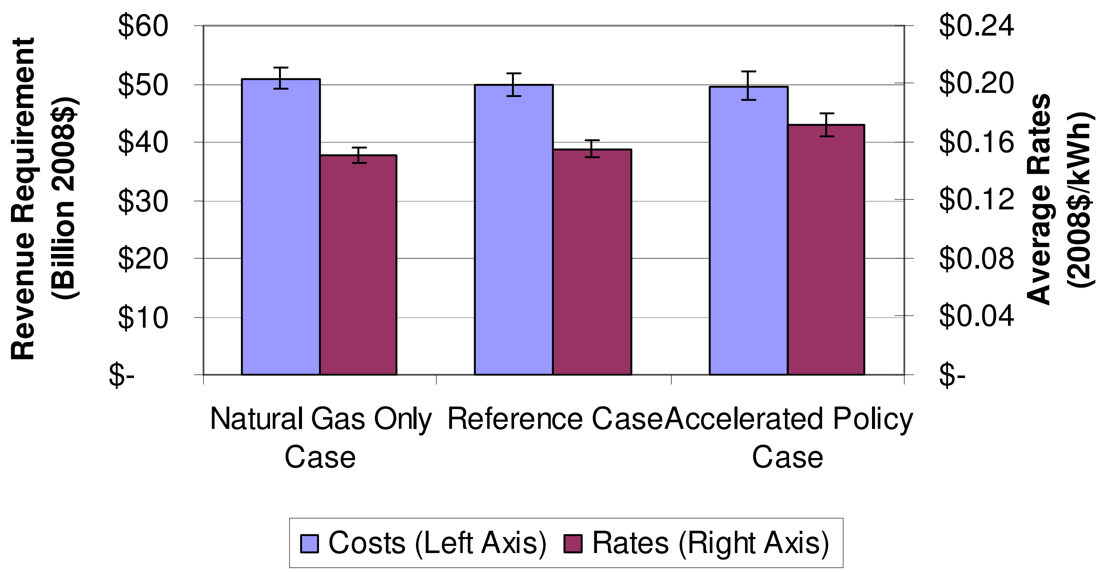
Figure 14. Sensitivity Analysis of Energy Efficiency Achievements on 2020 GHG Emissions by Scenario (error bars represent high EE goals and no incremental EE achievements, where applicable)



4.3 Load Growth

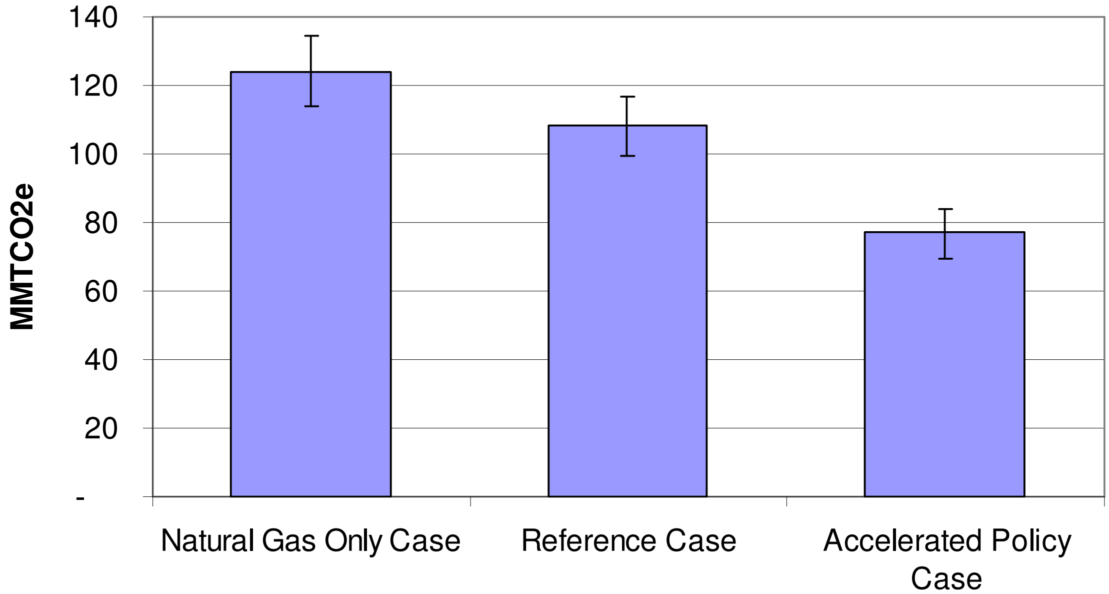
The Reference Case has an average annual load growth of 1.2% per year, the Accelerated Policy Case grows 0.3% per year and the Natural Gas Only Case by 1.6% per year. A sensitivity test on each of these cases is run, increasing and decreasing load growth by 0.5% per year. Figure 15 shows the impacts of this load growth sensitivity on statewide average utility cost and average statewide electricity rates. The figure shows that even relatively large long-term perturbations in electricity demand have relatively modest impacts on total statewide electricity costs (utility revenue requirement) and average statewide electricity rates.

Figure 15. Sensitivity Analysis of Load Growth on 2020 Statewide Revenue Requirement and Average Rates by Scenario (error bars represent +/- 0.5%/year change in load growth), updated for v.3b



As load growth increases, greenhouse gas emissions increase and vice-versa. Under the load growth sensitivities tested here, increasing and decreasing load growth by 0.5% per year results in a GHG emissions change of about +/- 9% in all scenarios.

Figure 16. Sensitivity Analysis of Load Growth on 2020 GHG Emissions by Scenario (error bars represent +/- 0.5%/year change in load growth)



5 Impacts to California Electric Retail Providers

The GHG Calculator disaggregates the statewide average cost and rate impact estimates for 2020 to forecast impacts on seven groupings of retail providers for each scenario analyzed.[28] The magnitude of the 2020 impact of each scenario on an individual retail provider or grouping of retail providers is influenced by a number of factors in the GHG Calculator. Here, we have highlighted a few of the key factors that influence the GHG Calculator's estimate of retail providers' 2020 cost and rate impacts:

- Generation Mix: including utility-owned generation, long-term power contracts (for renewable, hydroelectric, nuclear or fossil generation) defined here as "specified generation," and "unspecified generation" and the resulting emissions intensity of electricity,
- Current progress towards achieving Renewables Portfolio Standard (RPS) targets,
- Energy efficiency achievements, and
- Load growth.

These key factors for each of the retail providers modeled in the GHG Calculator are described below.

5.1 Generation Mix

Specified and Unspecified Power

California retail providers differ in terms of their ownership and contractual arrangements with specific generators. These differences, in turn, affect the impact on retail providers of various policies including the RPS requirements and of cap and trade policies. Therefore, we track specified power purchases, to the extent that they were known and publicly available as of 2008. "Specified" power, or specified purchases

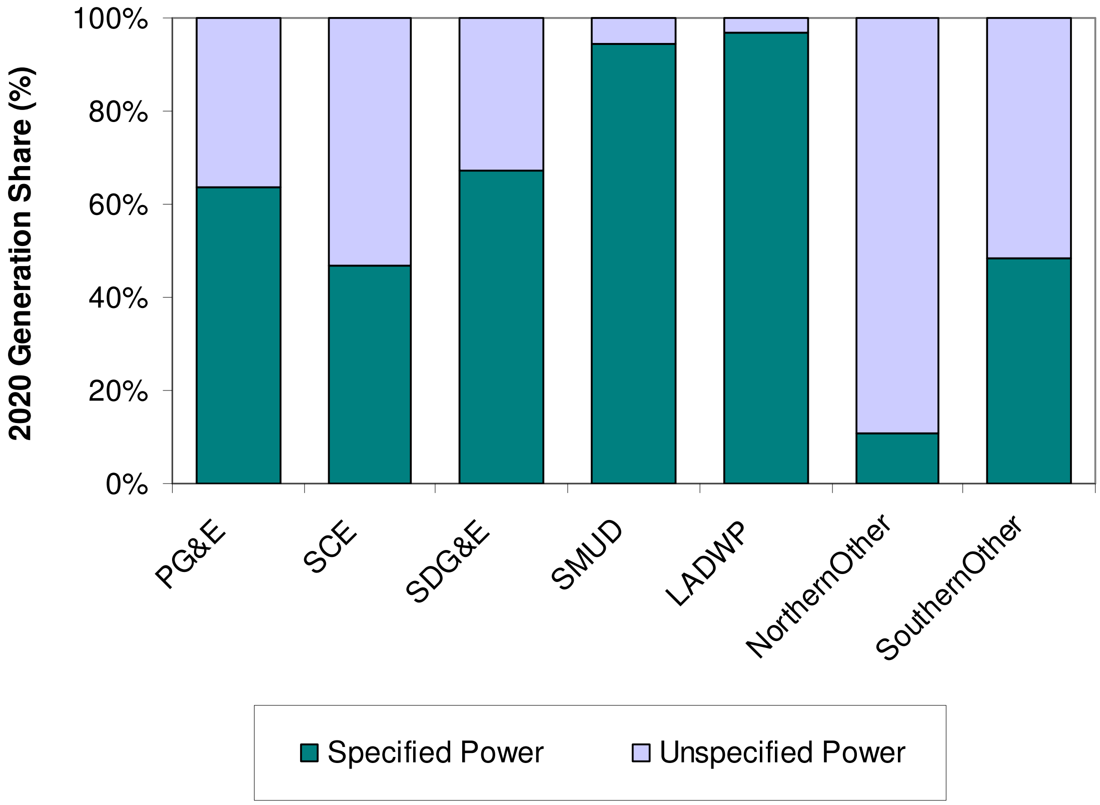
[28] The GHG Calculator does not calculate cost and rate impacts to the Water Agencies category of retail provider.

include power purchase agreements, bilateral contracts and utility-owned generation for either conventional or renewable generation. Retail providers' remaining power purchase needs, which are not met with specified purchases, are assumed to be met with "unspecified power" purchases. In the GHG Calculator, the default emissions intensity of unspecified power purchases is 1,100 lbs CO_2/MWh (0.5 metric tons CO_2/MWh).

A retail provider's share of unspecified power purchases increases its exposure to changes in market prices for electricity from a cap and trade program. Retail providers with higher shares of unspecified power purchases are more exposed to changing market prices of electricity, because they have not locked in long-term power purchase agreements.

The 2020 share of specified and unspecified power for each retail provider in the Accelerated Policy Case is shown in Figure 17 below. LADWP and SMUD have the most contracted and utility-owned generation of the retail providers modeled. As a result, these publicly-owned utilities are expected to be relatively protected from fluctuations in electricity market prices due to the addition of a price of carbon on GHG emissions. The "Northern Other" and "Southern Other" retail provider categories which include the state's direct access customers have the highest share of generation needs which are met with "unspecified power" in the GHG Calculator, meaning that in the model these retail providers are the most exposed to changes in the market price of electricity due to the introduction of carbon prices. However, the data availability regarding long-term contracts and generation ownership contracts for the "Northern Other" and "Southern Other" retail providers was relatively poor. As a result, the results for the Northern Other and Southern Other retail providers are not as robust as the results for the other retail providers.

Figure 17. 2020 Accelerated Policy Case Specified and Unspecified Power by Retail Provider



Coal-Fired Power Plant Ownership Shares and Long-Term Contracts

Another indicator of a retail providers' electricity costs are the relative share of long-term ownership agreements and contracts with coal-fired generators. Long-term power purchase agreements and other long-term contractual arrangements between retail providers and coal-fired generators can result in more stable electricity rates for consumers and can act as a price hedge against volatile natural gas prices and other fluctuations in short-term electricity prices. However, coal-fired generation is also high in GHG emissions and carries a CO_2 price risk.

Some existing contracts between California retail providers and coal-fired generators are slated to expire between 2008 and 2020, a fact which is reflected in the GHG Calculator default assumptions. Since coal-fired generation contracts generally deliver lower cost power than natural gas generation and renewable generation, coal contracts tend to lower a utility's electric rates. As a result, in the GHG Calculator, electricity rates generally increase for those retail providers whose current coal contracts end before 2020.

Table 6 shows the coal-fired generators that have long-term contracts or ownership arrangements with California retail providers. The table shows that SDG&E, LADWP, the "Water Agencies", and the "Northern California Other" and "Southern California Other" retail providers are all expected to see existing contracts with coal-fired generators expire before 2020. Under current law (Senate Bill 1368), retail providers are limited in their ability to renew contracts for more than five years with these coal plants (because the emissions rate of these generators exceeds 1,100 lbs/MWh). For the purposes of the GHG Calculator, we assume that the California utilities no longer purchase generation from a coal plant once the existing contract expires.

Table 6. Retail Provider Ownership and Contractual Shares in Coal-Fired Power Plants

California Retail Provider Owner/Contract Holder	Coal-Fired Generator	Unit #	2008 LSE Share of Generator (%)	Contract Expiration Date, if Before 2020
SDG&E	Boardman	1	15%	**2013**
Northern California Other			9%	**2013**
SCE	Four Corners	4 & 5	48%	No
LADWP	Intermountain	1 & 2	49%	No
Southern California Other			30%	No
LADWP	Navajo	1,2 & 3	21%	**2019**
Water Agencies	Reid Gardner	4	68%	**2013**
Southern California Other	San Juan	3	42%	No
Northern California Other		4	29%	No
Southern California Other		4	10%	No
Southern California Other	Bonaza	1	6%	**2009**
Southern California Other	Hunter	2	6%	**2009**

Emissions Intensity

Retail provider's utility-owned generation, long-term power contracts and unspecified power purchases are used to forecast retail providers' electricity emissions intensity over time under different scenarios. The Accelerated Policy Case results in a dramatic decrease in the emissions intensity of all of California's retail providers by 2020. The GHG Calculator estimates that the statewide average emissions intensity of electricity will drop over 30% in the twelve year period from 2008 to 2020, if the Accelerated Policy Case measures can be successfully implemented. In the Accelerated Policy Case, the average California emissions intensity of electricity is expected to drop from 0.34 tonnes/MWh in 2008 to 0.23 tonnes/MWh in 2020 (See Figure 18). This reduction in electricity emissions intensity is achieved through regulatory measures and the replacement of existing coal contracts with lower carbon power. The noticeable dips in 2013 and in 2019 in the emissions intensity of retail providers in the figure below are the result of large coal-contracts expiring (Boardman and Reid Gardner in 2013 and Navajo in 2019). The effects of all other emission reduction measures, such as renewable energy and energy efficiency, are assumed to be linear between 2008 and 2020.

Figure 18. Change in the Emissions Intensity of Electricity of Retail Providers in the Accelerated Policy Case Scenario (2008 – 2020)

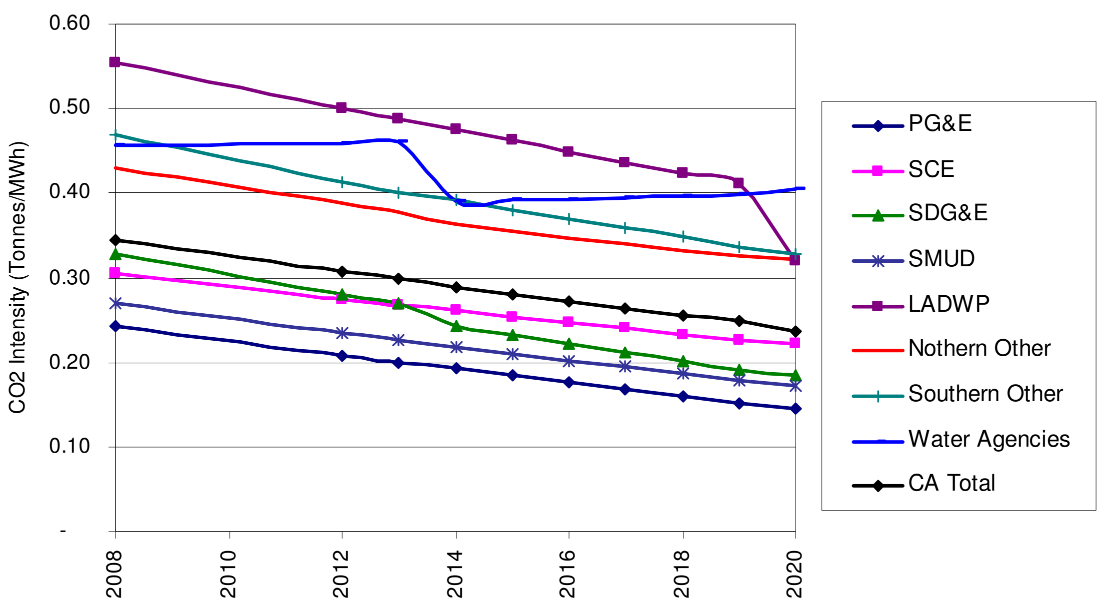
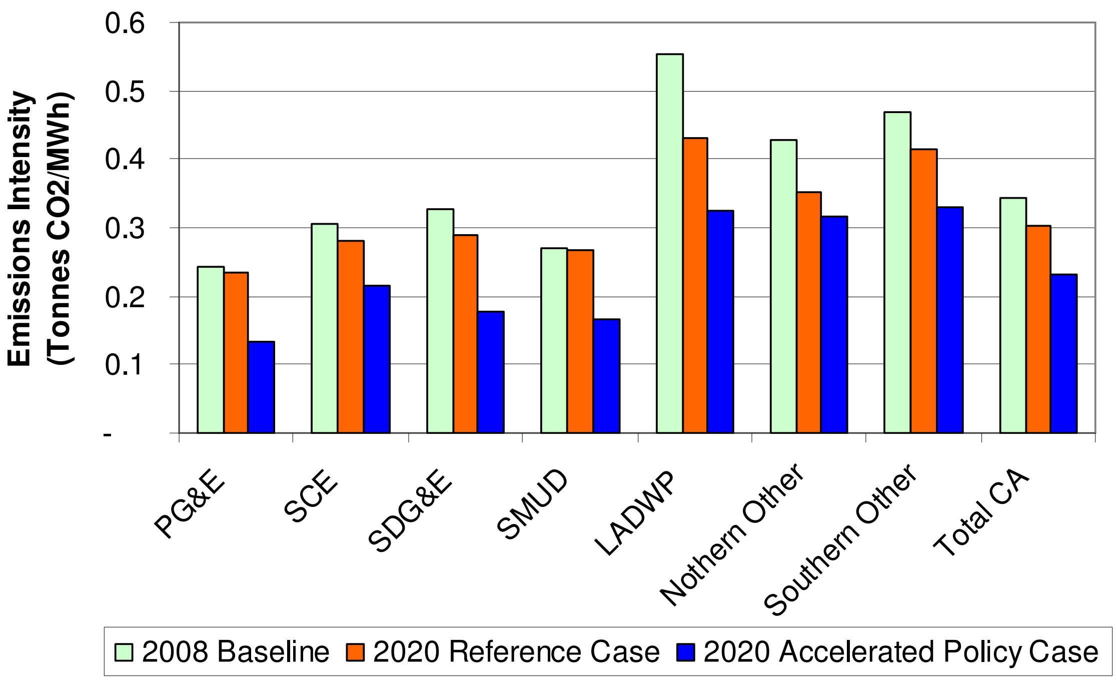


Figure 19 compares the emissions intensity of California retail providers in 2008 compared to the 2020 Reference Case and 2020 Accelerated Policy Case results. All retail providers show dramatic reductions in emissions intensity from 2008 to 2020 under both scenarios. In 2020, PG&E and SMUD are forecast to have the lowest emissions intensity. This is because these utilities are starting from a relatively low-carbon generation mix in 2008. Of course these emissions intensities are only forecasts, and individual retail providers could take any number of actions between now and 2020 to change their 2020 emission intensity.

Figure 19. Retail Providers' 2008 and 2020 Emissions Intensity by Scenario



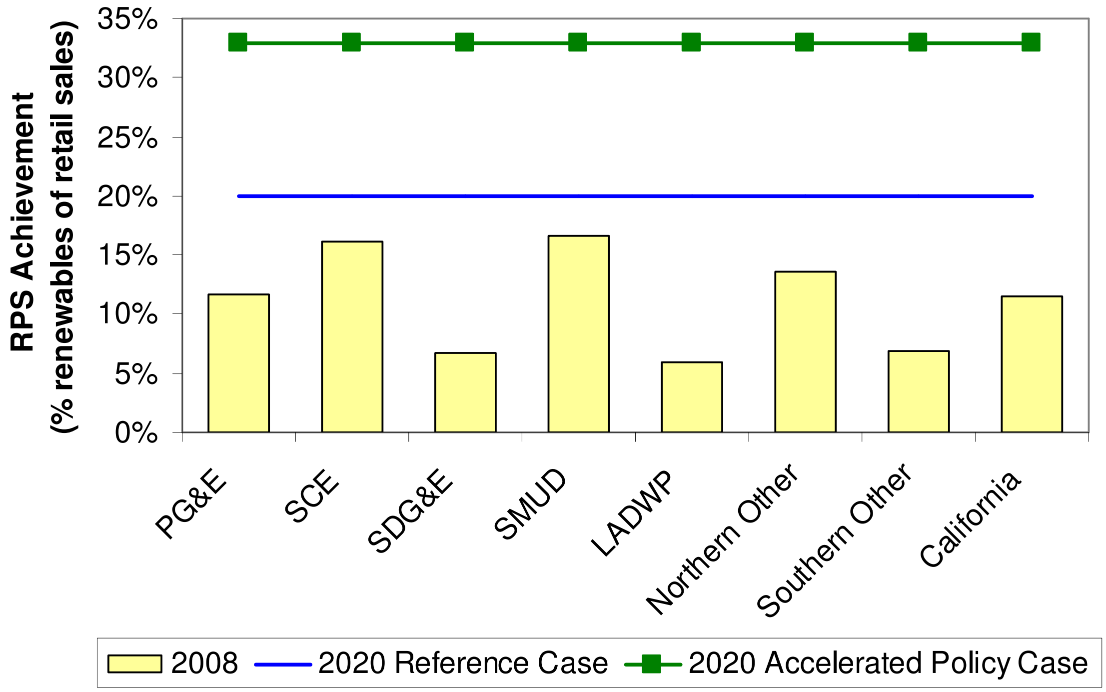
In other scenarios which include a carbon market and a price on CO_2 (the scenarios shown above do not include a CO_2 price), a retail provider's emissions intensity and its share of specified and unspecified power purchases become important indicators for understanding retail providers' estimated 2020 cost and rate impacts under different methods of allocating greenhouse gas allowances (auction, historic-emissions based allocation, output-based allocation, etc.). The impact of these different allocation scenarios on retail providers is discussed in Section 6.5.

5.2 Progress Towards RPS Targets

Another important predictor of the rate impacts and cost changes is a retail provider's 2008 level of RPS attainment. In the GHG Calculator, 2008 levels of RPS achievement are estimated for each grouping of retail provider. Under the Reference

Case, all retail providers are assumed to attain a 20% RPS by 2010 and maintain this level of RPS through 2020. Under the Accelerated Policy Case, all utilities are assumed to attain a 33% RPS by 2020. Retail providers that have higher levels of RPS attainment in 2008 generally see lower cost and rate impacts in 2020 because they do not have to procure as much additional renewable generation to meet the RPS targets. Figure 20 below shows that SMUD and SCE have the highest level of RPS attainment in 2008.

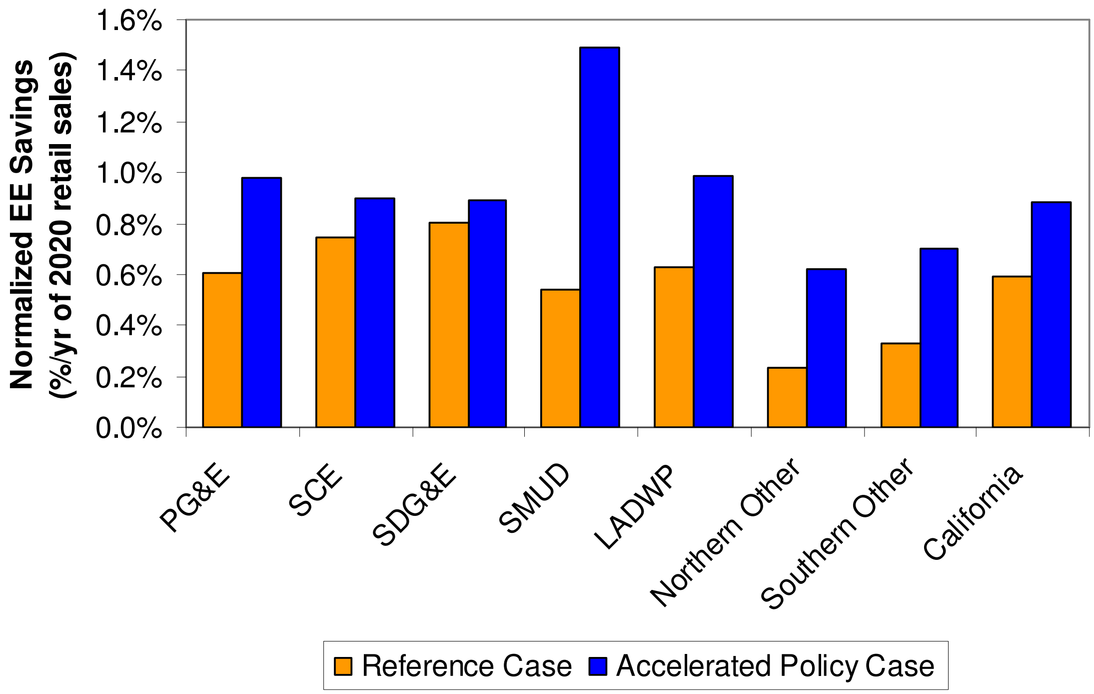
Figure 20. Retail Providers' Renewable Portfolio Standard Achievement in 2008 Relative to 2020 Scenarios



5.3 *Energy Efficiency Achievements*

Energy efficiency achievements are another important predictor of cost and rate impacts in 2020. Retail providers that achieve higher levels of energy efficiency will generally see higher rate impacts, but lower cost impacts. Energy efficiency reduces total sales, meaning that fixed utility costs must be spread across a smaller sales base, which tends to increase electricity rates. Energy efficiency reduces utility costs when an EE program's benefits to a utility are greater than its total costs. Figure 21 below summarizes the assumed annual energy efficiency savings for each retail provider as a percentage of their 2020 retail sales. The figure shows that SMUD in particular, has high expected energy efficiency achievements through 2020 as a percentage of its forecasted total electricity demand.

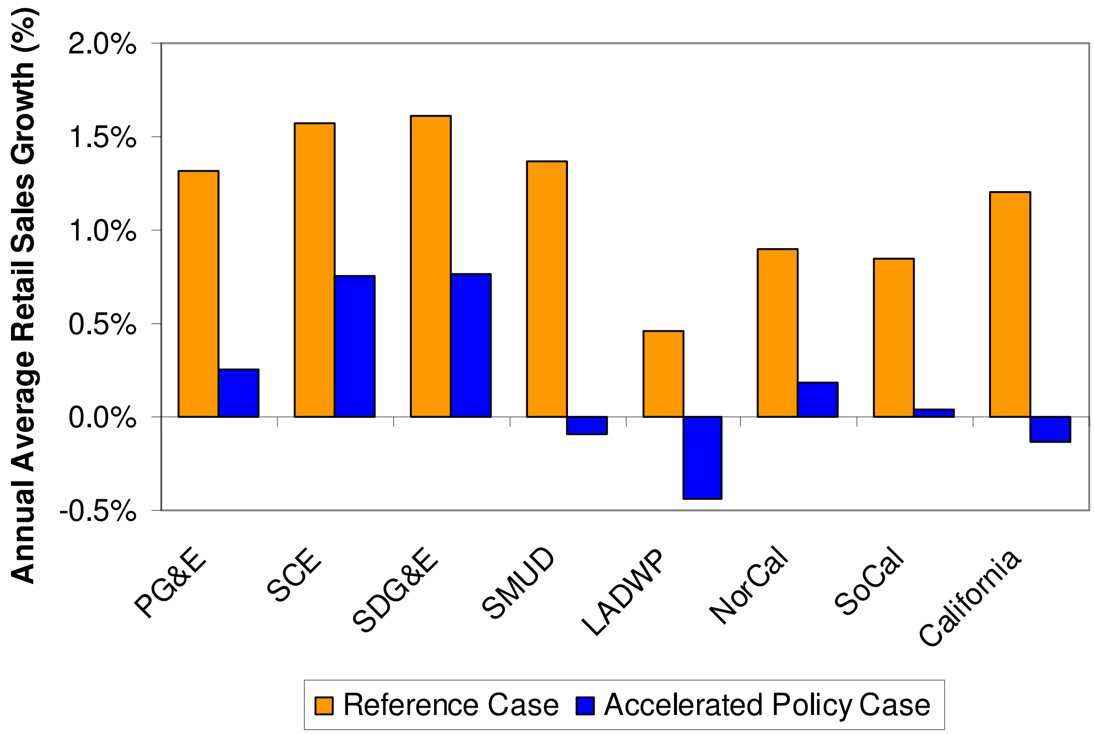
Figure 21. Normalized Energy Efficiency Savings per year (EE savings as a percentage of 2020 retail sales, divided by the number of years from 2008 – 2020)



5.4 Load Growth Forecast

Each retail provider's relative rate of growth in electric sales is another important determinant of rate impacts. Utilities with faster growth will generally experience smaller increases in rates, since costs can be shared over a larger customer base. Figure 22 below shows the relative rates of growth of each retail provider under the Reference Case and the Accelerated Policy Case. The Accelerated Policy Case shows lower growth for all retail providers because this scenario includes more aggressive demand-side measures, including energy efficiency and CHP.

Figure 22. Retail Providers' Annual Average Change in Retail Sales



In the figure, SMUD has a relatively high level of growth in retail sales under the Reference Case. However, the utility's aggressive energy efficiency targets in the Accelerated Policy Case result in negative load growth under that scenario. Likewise, LADWP has a relatively low annual average growth rate in the Reference Case, and a relatively high level of energy efficiency savings forecast in the Aggressive Case. As a result, LADWP ends up with a forecast of negative load growth in the Accelerated Policy Case.

5.5 Electric Retail Providers: Cost and Rate Impact Comparison with No Carbon Price

The combined impact of the factors discussed above results in different 2020 utility cost and rate impact estimates for each retail provider modeled in the GHG Calculator. While it is difficult to parse out the impacts and magnitude of each of these factors, some trends of note emerge.

LADWP is forecast to see the highest cost and rate increases among the group of retail providers analyzed here, in both the Reference Case and the Accelerated Policy Case. This higher impact to LADWP is due to the combined impact of LADWP's relatively inexpensive Navajo power contract expiring in 2019, which is then replaced with more expensive electricity purchases in 2020, as well as LADWP's relatively low 2008 RPS achievement and low forecasted load growth. In the Accelerated Policy Case scenario, LADWP load growth is forecast to fall to negative 0.4%/year due to the combined effect of energy efficiency, additional distributed generation such as combined heat and power generation, and a relatively initial low growth rate forecast.

However, despite the higher cost and rate impacts to LADWP estimated by the GHG Calculator, the 2020 LADWP rates are expected to be approximately equal to the statewide average electricity rate in 2020. This is because LADWP's rates start from a relatively low level in 2008. The three large IOUs (PG&E, SCE and SDG&E) are all expected to have slightly higher rates than LADWP in 2020 under either the Reference Case or the Accelerated Policy Case scenarios due to these utilities' relatively higher rates in 2008.

In contrast, SCE, SMUD and the Northern Other retail providers are expected to see the lowest cost and rate impacts in the Accelerated Policy Case, of the retail providers analyzed here. This is due to these retail providers' relatively high RPS achievements in 2008 relative to the 2020 targets as well as their relatively high load growth forecasts. These retail providers also do not have any coal contracts that are slated to expire before 2020, thus eliminating that as a source for potential cost and rate increases.

The cost and rate impacts by retail provider in 2008 and 2020 for the Reference Case and the Accelerated Policy Case are shown in Figure 23 and Figure 24 and in Table 7 and 8 below.

Figure 23. Average Utility Cost Impact to Retail Providers, 2008 and 2020 (real 2008 dollars), updated for v.3b

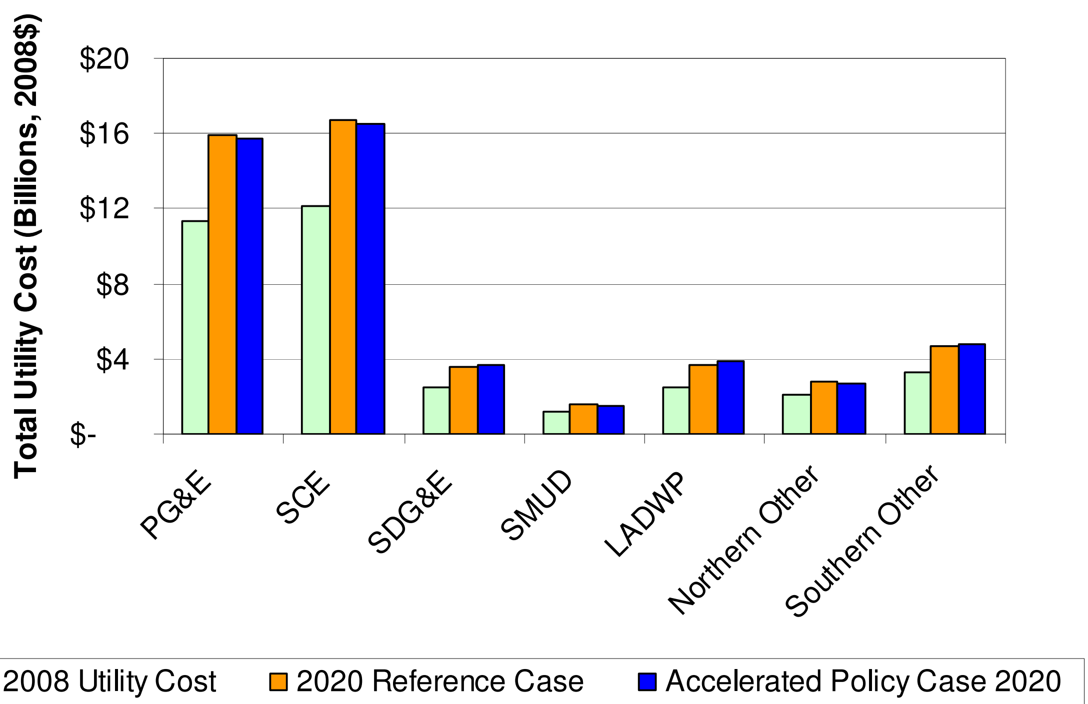


Table 7. Annual Average Percent Change in Utility Cost for California Retail Providers (2008 – 2020, real 2008 dollars), updated for v.3b

Retail Provider:	Reference Case: % change/yr.	Accelerated Policy Case: % change/yr.
PG&E	3.3%	3.2%
SCE	3.2%	3.0%
SDG&E	3.5%	3.8%
SMUD	2.7%	2.5%
LADWP	4.0%	4.6%
Northern Other	2.4%	2.1%
Southern Other	3.6%	3.9%
Total CA	**3.3%**	**3.2%**

Figure 24. Average Rate Impact to Retail Providers, 2008 and 2020 (real 2008 dollars), updated for v.3b

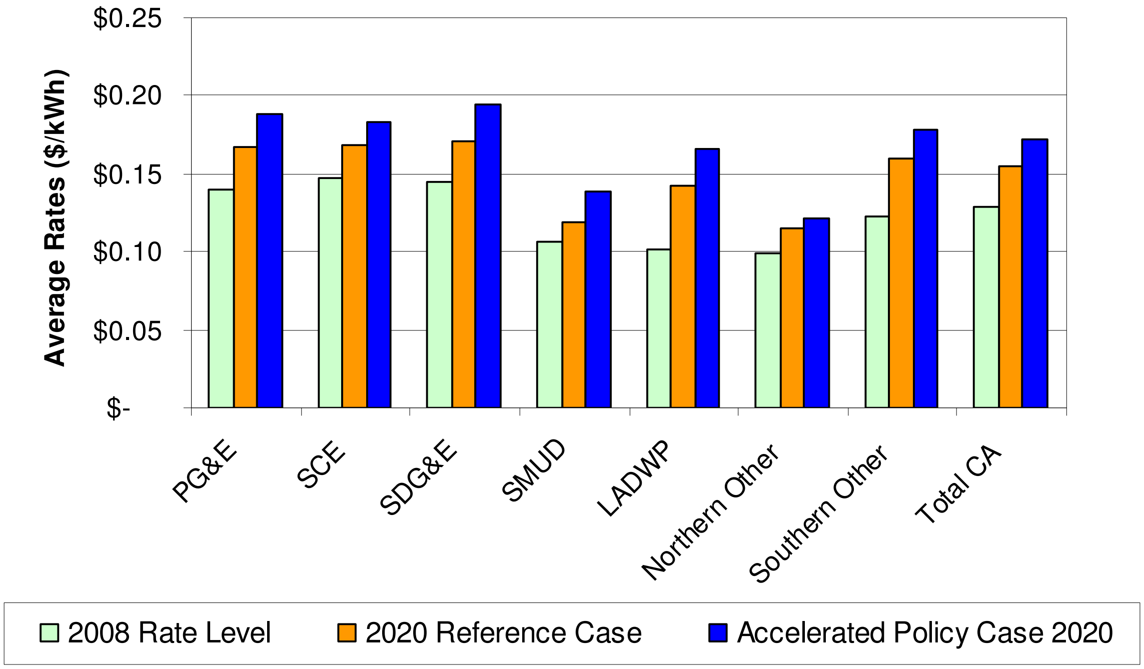


Table 8. Annual Average Percent Change in Average Electricity Rates for California Retail Providers (2008 – 2020, real 2008 dollars), updated for v.3b

Retail Provider:	**Reference Case: % change/yr.**	**Accelerated Policy Case: % change/yr.**
PG&E	1.6%	2.9%
SCE	1.2%	2.1%
SDG&E	1.4%	2.8%
SMUD	1.0%	2.6%
LADWP	3.4%	5.3%
Northern Other	1.3%	1.9%
Southern Other	2.5%	3.8%
Total CA	**1.7%**	**2.7%**

6 Analysis of Cap and Trade Policies

6.1 Methodology

The GHG Calculator models the impact of a GHG price on California's electricity sector and groupings of retail providers in 2020. The GHG price is selected by the user of the GHG Calculator; the GHG price is not determined endogenously within the model. The underlying assumption is that by 2020, a multi-sector statewide, regional or federal cap and trade program will be in place. We therefore assume that the GHG price will not be set by the California electricity sector alone, but will be set by a combination of policies and emission reduction costs across many sectors of the economy. Thus, the exogenously selected GHG price could be chosen to reflect California's participation in the Western Climate Initiative or California's participation in a federally sponsored cap and trade market.

For most of the cap and trade scenarios analyzed here, the GHG price is assumed to be $30/tonne from 2012 through 2020. The selection of a $30/tonne GHG price is not reflective of any presumption that this price is the most likely or most desirable GHG price for California in 2020. Rather, $30/tonne was selected for these scenarios to reflect a price that is neither very high, nor very low. For the purposes of this analysis, the most interesting results come from comparing the relative impacts of a GHG price among retail providers. As a result, the absolute GHG price selected is not as important to this analysis.

In the GHG Calculator, the price of GHG emissions allowances in a cap and trade policy scenario increases the price of wholesale electricity market purchases. The wholesale market price of electricity in California is generally set by the cost of natural gas generation. Thus, a GHG price will generally increase the marginal cost of generation proportionally with the emissions intensity of the marginal natural-gas fired generation unit(s). One exception to this rule is expected to occur if GHG allowances are administratively allocated to generators based on their electricity output, in a policy referred to here as "output-based allocation." The theory underlying this policy choice will be discussed further in Section 6.5.

In addition to affecting the market clearing price of electricity, the price of GHG emission allowances is also expected to impact the marginal cost of generation for fossil-fuel power plants that do not operate in the wholesale electricity markets, but which operate under long-term contractual or ownership terms with electric retail providers. In these cases, the GHG Calculator assumes that allowance prices are simply passed through from generators to retail providers at the actual cost of allowances for these generators.

Zero-carbon generation sources, such as renewable energy, large hydroelectric generation and nuclear power, which are owned by retail providers or which are under long-term contracts with retail providers, are expected to have no carbon-compliance costs. In the GHG Calculator, GHG allowance prices do not affect the electricity price passed through to retail providers for these zero-carbon generation units which are owned or contracted by retail providers.

The GHG Calculator is also designed to investigate the relative impacts of different greenhouse gas allocation policy choices on California's electric retail providers. Policy choices that can be modeled in the GHG Calculator include:

- Percent of GHG allowances that are administratively allocated for free versus auctioned to generators;
- If administrative allocation is selected, percent of allocation that is based on a generator's historic (2008) energy emissions versus a generator's current year output (GWh). Allowances may be allocated either to all generators, or only to fossil-fuel based generation ;[29]

[29] In the GHG Calculator, historic energy sales are based on simulated generation from the 2008 PLEXOS model runs. This does not constitute a recommendation for how to administer a historic allocation policy. In practice, allocation to generators based on their historic output could be based on generation averaged over a number of years, for example, to smooth out variations in hydroelectric output.

- If auction is selected, percent of auction revenue that is returned to retail providers, either on the basis of the retail providers' yearly sales, or on the basis of the retail providers' historic (2008) emissions;[30]
- Greenhouse gas offset prices, as well as limits on the applicability of offsets to meeting the electricity sector greenhouse gas allowance requirement.

All of these policy variables can be adjusted over time between 2012, when the cap and trade market is assumed to begin, and 2020. This means that the GHG Calculator allows policy makers to analyze the cost and rate impacts of "transitional" greenhouse gas allocation policies, which could change between 2012 and 2020.

6.2 Impact of Cap and Trade on Western Region

The California Air Resources Board Scoping Plan, adopted in December 2008, calls for California's cap and trade program to link "with other Western Climate Initiative Partner programs to create a regional market system to achieve greater environmental and economic benefits for California."[31] One of the environmental benefits of linking a California cap and trade program to other regions in the West is that such linkages may reduce the opportunity for 'leakage' of greenhouse gas emissions and 'contract shuffling.' 'Leakage' is defined as a shift in generation which reduces GHG emissions among entities that are regulated by a cap and trade program, while increasing GHG emissions among entities that are not regulated by a cap and trade program. For example, leakage would occur if California sought to reduce its GHG emissions by simply importing more electricity from out-of-state, without fully accounting for the GHG emissions associated with producing the out-of-state power. 'Contract shuffling' is an action that reduces GHG obligations of an entity regulated within a cap and trade

[30] In the GHG Calculator, historic retail provider emissions are based on 2008 estimates of greenhouse gas emissions. This does not constitute a recommendation for how to administer a historic emissions-based auction revenue return. In practice, historic emissions could be calculated for retail providers averaged over a number of years, for example, to smooth our variations in hydroelectric output.

[31] California Air Resources Board, Scoping Plan, adopted December 2008, pg. 30. Available at: http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

program, without any change in actual power plant operations or change in total GHG emissions. For example, contract shuffling would occur if a California utility sold one of its out-of-state power contracts with a coal-fired generator to an out-of-state entity, and California then claimed credit for reducing its GHG emissions, despite the fact that the coal-fired power plant continued to run and operate just as it had before the contract changed ownership.

Whether or not leakage and contract shuffling become a cause for concern in a California cap and trade program will depend on the rules and regulations in the cap and trade program, as well as the geographic extent of the program. Currently, both of these factors are uncertain. As the final regulations surrounding a cap and trade program are designed, more research will likely be required to determine appropriate market rules to minimize leakage and contract shuffling.

The GHG Calculator analysis did not include an investigation of leakage and shuffling issues in a regional cap and trade system. However, some research on this topic has been undertaken by academic researchers.[32] In addition, the Western Climate Initiative has sponsored some analysis of some of these leakage and contract shuffling questions. On October 16, 2008, the Western Climate Initiative hosted an Electricity Subcommittee Technical Working Session in Salt Lake City Utah which discussed issues surrounding policies and regulations to limit the potential for leakage and shuffling.[33] A WCI leakage analysis performed by E3 for this working group concluded that the potential for leakage could be large, unless mitigated with appropriate regulation.[34]

Another environmental benefit of linking a California cap and trade program to other regions is that a regional or federal cap and trade program could help to reduce the emissions intensity of electricity imported into California. As part of the GHG analysis

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[32] See for example: Bushnell, James and Yishu Chen, "Regulation, Allocation, and Leakage in Cap-and-Trade Markets for CO_2," Center for the Study of Energy Markets Working Paper, University of California Energy Institute, CSEM WP 183, March 2009.

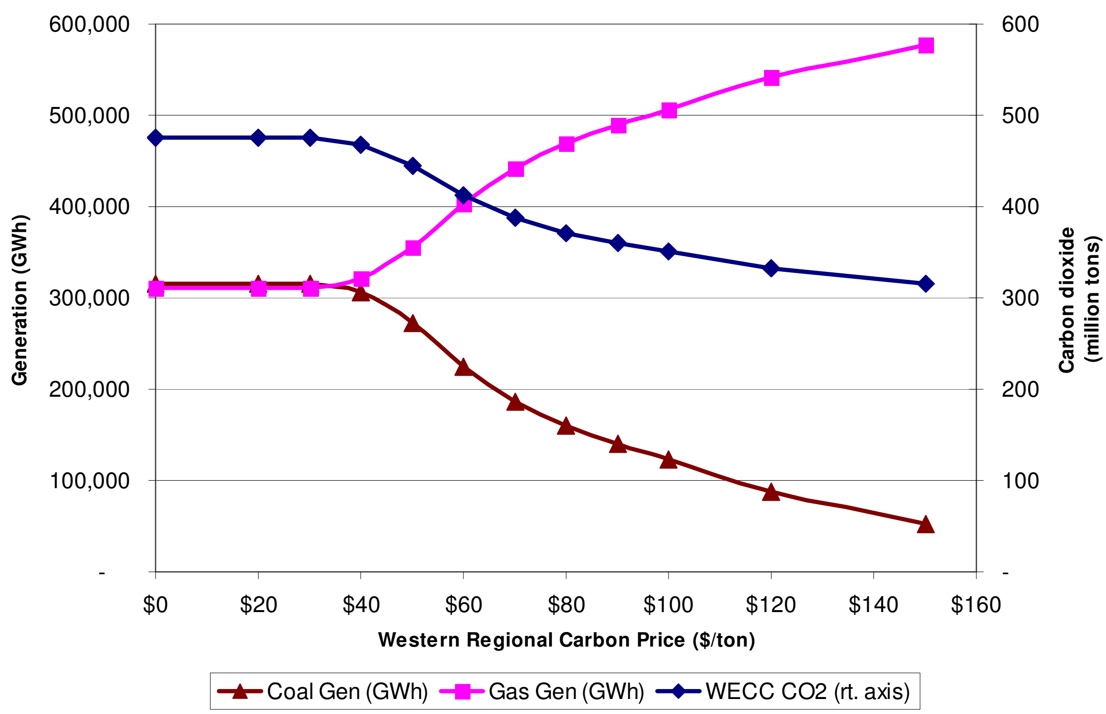
[33] Documents from the WCI October 16th, 2008 Electricity Subcommittee Technical Working Session are available at: http://www.westernclimateinitiative.org/WCI_Meetings_Events.cfm

[34] See WCI October 16, 2008 "E3 Leakage Presentation," available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20156.PDF

undertaken in this project, E3 investigated the question of what GHG price would be required to change the operational patterns of natural gas and coal-fired generators that are expected to be in operation across the Western Electricity Coordinating Council (WECC) in 2020.

Using the production simulation dispatch model PLEXOS, a number of 2020 simulation runs were run, applying different GHG prices to all WECC generators. This analysis found that, at a natural gas price of $7.85/MMBtu and a coal price of $1.01/MMBtu, natural gas generation does not begin to displace coal fired generation in the WECC until the GHG price rises to about $50/tonne. Significant CO_2 reductions, due to the displacement of coal with natural gas, begin occur once the CO_2 price reaches $60/tonne (Figure 25). If the price of coal were to increase relative to natural gas, a lower CO_2 price could induce changes to the natural gas and coal power plant dispatch.

Figure 25. PLEXOS Results for 2020 WECC dispatch under Different WECC-wide CO_2 Prices



This WECC-wide CO_2 price analysis considered the impact of CO_2 prices on existing generation, which is expected to still be operational in 2020. A WECC-wide cap and trade policy could induce different investment decisions in new generation build, which would also affect the total WECC-wide CO_2 level in 2020. Estimating the dynamic impacts of a WECC-wide cap and trade policy on future investment choices is not undertaken here.

6.3 Impact of Cap and Trade on California's Electricity Sector

There are a number of potential ways that a cap and trade policy could be expected to affect California's electricity sector. Many, though not all of these impacts, are modeled in the GHG Calculator. The potential impacts of a cap and trade policy include:

- Change in the dispatch of existing generation;
- Reduction in the emissions intensity of electricity imports;
- New low-carbon generation investment;
- Reduction in electricity demand due to higher electricity prices;
- New low-carbon technology development and market transformation; and
- Distributional economic impacts.

Existing theoretical literature and empirical studies of cap and trade programs on sulfur-dioxide and nitrogen-oxide gases, suggest that cap and trade programs could achieve emission controls at a lower total compliance cost than other approaches. However, given the ambitious GHG reduction goals laid out for the entire state of California under AB 32, complementary policies are likely to be necessary to achieve the GHG target, in addition to market-based mechanisms. We find that a California-only cap-and-trade system is likely to increase costs in the electricity sector without achieving meaningful additional GHG reductions, beyond the level of complementary policy reductions, unless one of the following or a combination of the following conditions occur:

- Carbon prices reach high levels (\$100/tonne CO_2e or more);
- Natural gas prices increase significantly (100% or more from the Reference Case assumption of \$7.85/MMBtu);

- Technology innovation reduces the relative cost of low-carbon electricity resources compared to natural gas generation, or technology improves the performance of low-carbon technologies significantly;
- Lower-cost emission reduction opportunities are available from other sectors under the cap-and-trade program (though in this case the GHG reductions would come from those sectors and not the electricity sector. This condition would serve to reduce the cap and trade compliance costs to the electricity sector, but would not reduce emissions from the electricity sector).

The next sections discuss the analysis and reasons underlying these cap and trade findings for California's electricity sector.

There are potential benefits of a cap and trade program as well. First, a strict, well-enforced GHG cap in a cap and trade program could help ensure that California meets its 2020 GHG target if one or more of the complementary programs in the CARB Scoping Plan fall short of the expected GHG savings due to unforeseen circumstances. Second, if the California cap and trade program links to other jurisdictions, as is currently planned under the Western Climate Initiative, California may be able to purchase lower-cost GHG allowances than would be available in a California-only cap and trade market or under additional complementary policies. Trading GHG permits across a broad jurisdiction has the potential to save Californians money while reducing global GHG emissions.

Dispatch of Existing Generators

Part of the reason that a CO_2 price must be in the range of $100/tonne before a cap and trade program is likely to induce significant changes in the California electricity sector is because, unlike the WECC region as a whole where lower GHG prices could have an important impact on generation dispatch, the California electricity sector contains very little coal-fired generation. This means that there is relatively little opportunity within California to substitute natural gas fired generation for coal-fired generation. The CO_2 emissions that California attributes to coal-fired generation largely come from imported electricity through long-term contracts or ownership arrangements with out of state coal-fired generators. This means that the addition of a CO_2 price on California generators is not likely to change the dispatch, or operational patterns of existing coal generators relative to natural gas generators.

However, this could change if California's cap and trade program were linked to other jurisdictions, such as is currently proposed under the Western Climate Initiative. Since there is a significant amount of coal-fired generation in the Western Interconnect, a regional cap and trade program has the potential to tip the balance between coal and natural gas, potentially leading gas to displace some coal on the system (as described in Section 6.2 and shown in Figure 25). If a regional cap and trade program were rigorously enforced, CO_2 prices could result in a switch from gas to coal, generating significant reductions in GHG emissions and other important environmental co-benefits.

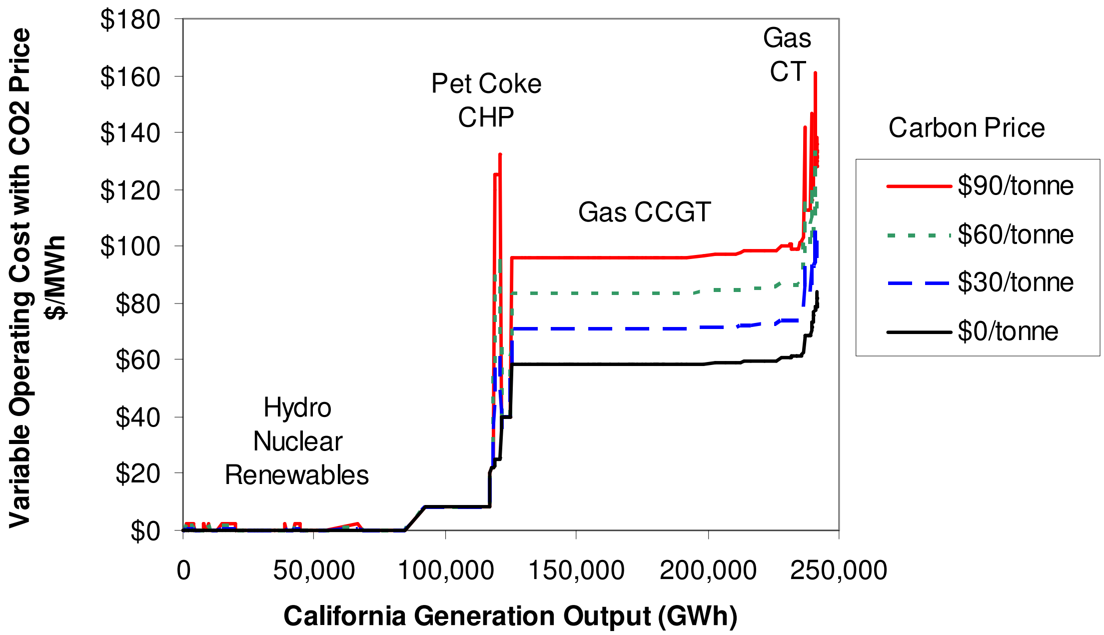
Figure 25, in the previous section, demonstrated that in the WECC as a whole, CO_2 prices must be at least $50 or higher before natural gas generation is likely to be cheaper than coal, using the Reference Case fuel price assumptions. Therefore, the emissions intensity of imported electricity is not likely to change significantly unless the CO_2 price rises above $50/tonne across the WECC as a whole, and California's retail providers no longer have contractual obligations to import coal power.

Another challenge associated with attempting to use a CO_2 price to change generator dispatch comes from the physical reality of power plant efficiencies. Power plants already operate under strong economic incentives to operate as efficiently as possible in order to maximize profits. Improving the efficiency of an existing thermal power plant generally requires that it be entirely overhauled or rebuilt with newer, more efficient technology. This means that in the short-run, without building new power plants and replacing older ones, it is difficult to improve thermal power plant efficiency.

The efficiency of a natural gas combined cycle power plant is an important determinant of its variable, or operating cost. In the wholesale electricity market in California, generators bid into the market based on their marginal cost, and are dispatched from lowest to highest bid. Figure 26 shows that currently, as long as California generators are dispatched in economic order, then they are also dispatched in order of their emissions intensity: hydropower, nuclear power and renewable energy have basically no marginal cost, as well as no GHG emissions, and are dispatched first. Gas generators in California are also dispatched in economic order, from the most efficient combined cycle units (CCGTs) first to the least efficient combustion turbines (CTs) last. This dispatch order corresponds with their emissions intensity rank order. The introduction of a CO_2 price increases the variable cost of natural gas generation, however, it does not change the relative costs of different natural gas generators.

One exception to this rule is the state's petroleum coke (Pet Coke) generation units. As can be seen in the figure, a \$60 or \$90/tonne CO_2 prices can tip the balance, increasing the variable cost of the petroleum coke units such that they are higher than the variable cost of natural gas CCGT units. However, the state's petroleum coke units are mostly located at industrial and refining facilities, and/or are co-generation units. These units are generally running primarily in support of industrial processes rather than primarily as participants in wholesale electricity markets. This means that these units are not likely to change their dispatch patterns due to a GHG price signal if it would disrupt the industrial process they serve.

Figure 26. Variable Cost of California's 2020 Reference Case In-State Generation under Different CO_2 Price Assumptions



Reduction in the Emissions Intensity of Electricity Imports

While California contains very little in-state coal-fired generation, approximately 9% of the electricity sector's emissions (about 10 million metric tons of CO_2) is expected to come from specified contracts with out of state coal-fired generators in 2020 in the GHG Calculator Reference Case. These out-of-state coal contracts are currently cheaper than wholesale electricity purchases because in general, coal is cheaper than the natural gas that sets the wholesale electricity market clearing price in California. However, the introduction of a CO_2 price could change the relative economics of out-of-state coal imports relative to California's wholesale electricity prices.

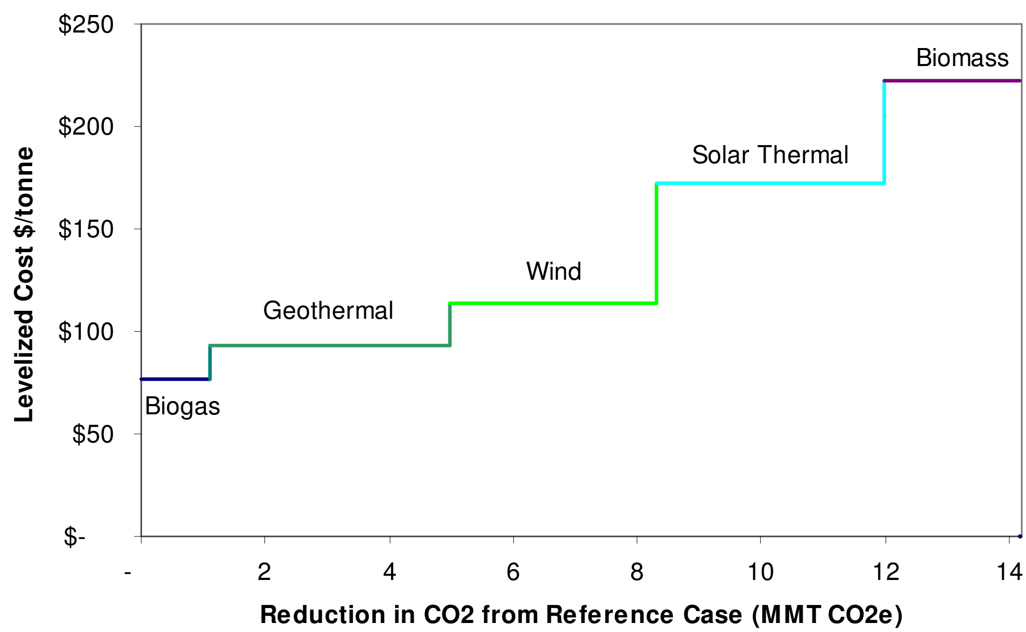
New Low-Carbon Generation Investment

A cap and trade program in California is likely to increase the cost of fossil-fuel fired generation relative to the cost of zero-carbon and low-carbon resources. This relative price change could encourage investment in new low-carbon generation technologies. However, as long as natural gas and coal remain relatively cheap

(Reference Case assumptions of $7.85/MMBtu for natural gas and $1.01/MMBtu for coal), the price of CO_2 would need to rise above approximately $100/tonne before current low-carbon generation technologies become economic relative to fossil-fuel fired generation.

Figure 27 shows that, under current technology costs and fuel price costs, the cost of reducing emissions with new renewable energy (with the exception of biogas) is above $100/tonne of CO_2. This figure includes the average cost of delivering renewable resources located out-of-state to California.

Figure 27. Renewable Energy Supply Curve (Levelized Cost $/tonne CO_2 reduction)



Reducing Electricity Demand due to Higher Electricity Prices

Another potential impact of a cap and trade program in the California electricity sector is increased prices of electricity. A CO_2 price is likely to increase the price of electricity by introducing a higher variable cost to natural gas fired generation, which in California, tends to set the wholesale market clearing price of electricity (this concept is further discussed in Section 6.4). Generally, higher prices reduce the quantity of demand for a product, even for a necessary consumer good such as electricity. If higher CO_2 prices reduce electric demand, and do not simply drive sources of electric demand to other regions of the country or the world, then a cap and trade program may be credited with reducing greenhouse gas emissions in the electricity sector through the price signal impact on consumer demand.

How much might electricity demand fall due to higher electricity prices? This is a question that economists have investigated for many years, using a metric known as the elasticity of electric demand. In general, prior research suggests that in the short run the elasticity of demand for electricity is fairly low, on the order of -0.1 to -0.3, because electricity is usually a necessity rather than a luxury good.[35] This means that a rate increase of 10% due to the introduction of a CO_2 price on electricity would reduce consumption by 1% to 3% between 2008 and 2020. This level of demand reduction would save about 2 million metric tons of CO_2. In the short-run, we do not believe that reductions in electricity demand, due to higher electricity prices, represent a major source of GHG savings.

In the long-run, consumers can adapt to higher electricity prices by finding ways to reduce their electricity consumption, largely through the adoption of more energy efficient technologies. The high levels of energy efficiency included in the Aggressive Policy case are likely to reflect the long-run price response of consumers to the higher electricity rates that result from that scenario.

New Low-Carbon Technology Development and Market Transformation

A higher market price for electricity and a CO_2 price could drive new technology innovation, resulting in new sources of emission reductions. The ability of a cap and trade program to harness the power of market innovation through profit making incentives has historically been a powerful argument in favor of market-based policies such as a cap and trade program. However, predicting how, when and under what circumstances technology innovation is likely to occur is fraught with difficulty.

[35] Energy Information Agency (2009), "Assumptions to the Annual Energy Outlook 2009," Report #: DOE/EIA-0554(2009). http://www.eia.doe.gov/oiaf/aeo/assumption/index.html

Although it is certainly possible that a cap and trade program, or any other emission reduction program, will drive technology development and market transformation in new low-carbon technology, we do not seek to model this effect.

Economic Distributional Impacts

The introduction of a cap and trade program inevitability creates differential distributional impacts across different regions of the state and among different types of electricity consumers and producers. Indeed, any policy that seeks to change the status quo will inevitably have some distributional impacts, many of which could stimulate positive change. The CPUC and CEC have stated that a cap and trade policy should result in, "equitable and fair treatment of market participants."[36] This consideration underpins the analysis described in the following section, which considers some of the distributional impacts of a cap and trade policy in California's electricity sector. The next section of this report begins by considering the distributional impacts between producers and consumers in the electricity sector (generators and loads), and next considers the distributional impacts between different retail providers in California.

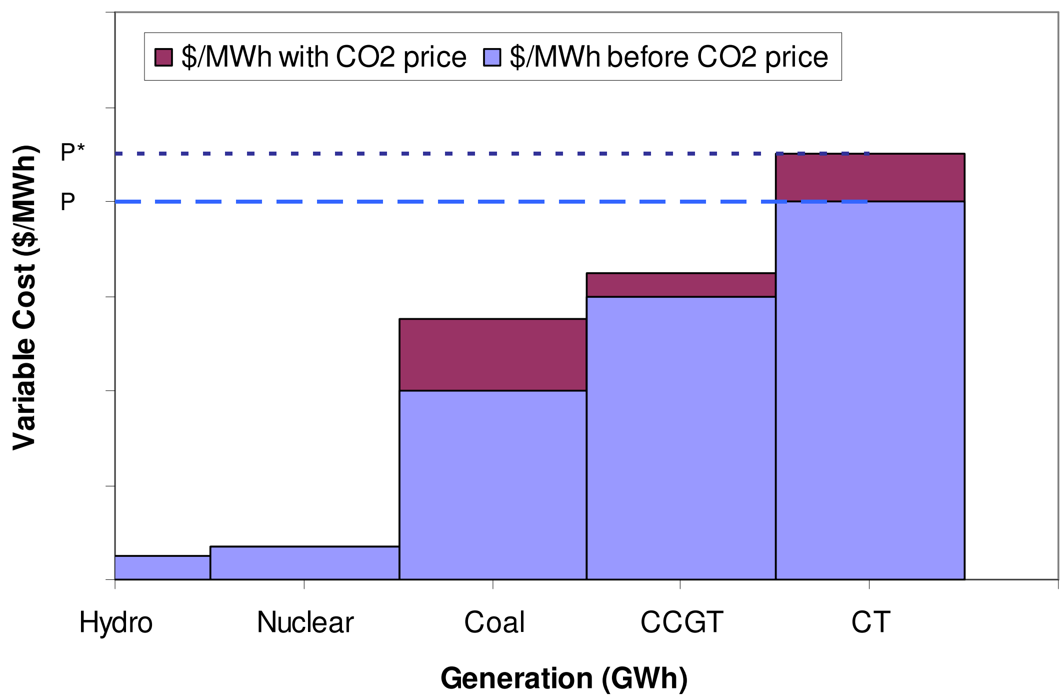
6.4 Producer and Consumer Surplus Impacts of CO_2 Price on Electricity

Under almost any cap and trade program (or carbon tax program) a CO_2 price on electricity will increase the market clearing price of electricity. This will lead to an increase in producer surplus (additional profits) for lower emission generators at the expense of consumers. This is because in California there is a single market clearing price for electricity which is generally set by natural-gas fired generation. The stylized example in the figure below demonstrates how a CO_2 price increases producer surplus for most generators. Initially, the market clearing price of electricity is "P"; as determined by the price point at which electricity demand is equal to electricity supplied. All generation which has a lower variable cost than the final generator that is required to meet supply obtains producer surplus equal to the difference in the market clearing price and their

[36] CPUC Decision 08-10-037 in Rulemaking R.06-04-009, pg. 144.

variable cost. A CO_2 price increases the variable cost of fossil-fueled generation, resulting in a new, higher market clearing price of electricity, "P*". The new, higher electricity price increases the producer surplus for any generator with a lower emissions intensity than the marginal generator. This results in an increase in 'rents to clean generation' equal to the difference in P* and P less the generator's change in variable cost due to the CO_2 price.

Figure 28. Stylized Example of Change in Electricity Sector Producer Surplus due to CO_2 Price



If GHG allowances are allocated to generators free of cost, another source of benefits is accrued to the generators that receive the free allowances. This benefit is known as 'allowance rents.' Allowance rents can be recouped by the state if GHG allowances are auctioned rather than allocated to generators free of charge. However the 'rents to clean generators,' due to a higher market clearing price of electricity, cannot be recouped through an auction. Even under an auction, the market clearing price increase will lead to an increase in producer surplus which the state, or consumers, cannot recoup.

If CO_2 allowances were auctioned to generators at a CO_2 clearing price of $30/tonne, and if these auction revenues were returned to California retail providers, the GHG Calculator estimates that the state would pay an additional $500 to $700 million in 2020 in the form of producer surplus to generators. Relative to California's expected 2020 electricity sector annual costs of about $50 billion, this rent to generators would represent an electricity sector cost increase of less than 2%. This cost calculation assumes that low-carbon generation which is currently either owned or in long-term contracts with utilities will not reflect the change in electricity market clearing prices in their power sales. The details of specific long-term power contracts would need to be analyzed if this assumption were to be further refined.

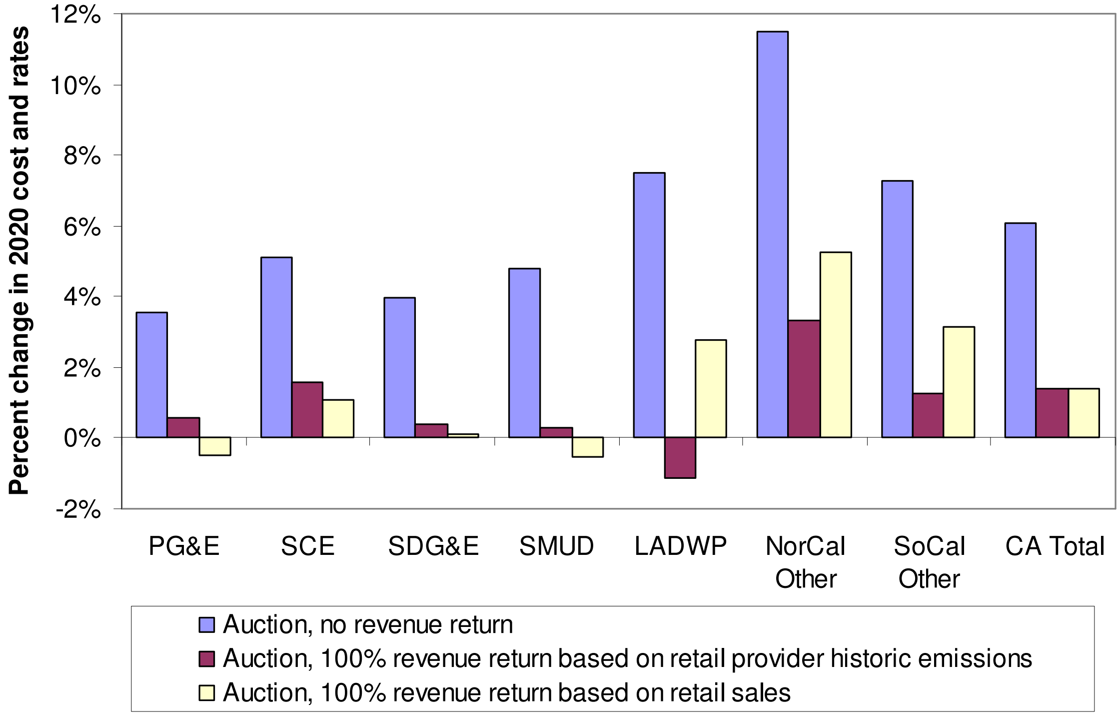
6.5 Impact of Cap and Trade Policy on California's Electric Retail Providers

The Joint Decision's recommended approach for the cap and trade allocation policy in the electricity sector by 2016 is a full auction. A full auction means that a generator must purchase, in an auction, the amount of GHG allowances that it will need each year, in an amount equal to the generator's GHG emissions. There are three main policy options to allocate the revenue generated from a GHG allowance auction: 1) the auction revenue could be spent by the state outside of the electricity sector; 2) the auction revenue could be returned to retail providers on the basis of their historic emissions; or 3) the auction revenue could be returned to retail providers on the basis of their current retail sales. Some combination of these three options is possible as well. Figure 29 shows the 2020 impact to retail providers of three different options for the auction and revenue return of GHG allowances. These three options, assuming a $30/tonne CO_2 price, and the impacts of those options on retail providers in 2020, are described below:

- ***Auction, no revenue return:*** Under this policy, utilities see the highest cost and rate impacts. Costs are highest under this option because the revenues from the auction are used by the state for purposes other than reimbursing electric retail providers. Under this option, costs and rates increase between 3% and 10% higher in 2020 than they would have been under the Accelerated Policy Case with no GHG price.

- ***Auction, 100% revenue return based on retail provider historic emissions:*** Under this policy, retail providers that have historically had higher GHG emission are compensated with a higher allocation of GHG emissions allowances. This policy would benefit retail providers with a historically higher emissions intensity. In the GHG Calculator, LADWP sees lower costs and rates under this policy in 2020 relative to the Accelerated Policy Case with no GHG price. Even though the Northern Other retail providers have a relatively high emissions intensity, this grouping of retail providers still shows a relatively high cost and rate impact under this policy. This is because the Northern Other retail providers have a high proportion of "unspecified power purchases", meaning that they are more exposed to higher market prices of electricity due to the GHG price than other retail providers with a lower share of unspecified power purchases.
- ***Auction, 100% revenue return based on retail sales:*** Under this policy, retail providers receive GHG allowances based simply on their total retail sales. This policy means that the retail providers with the lowest GHG emissions intensity (GHG emissions per MWh of sales), fare the best. Since PG&E and SMUD are forecast to have the cleanest generation mix in California, these retail providers would actually see a decrease in their rates due to this policy, relative to the Accelerated Policy Case with no GHG price. Retail providers with relatively carbon-intensive generation mixes, like LADWP, and Northern Other would see higher costs impacts under this policy.

Figure 29. Percent change in 2020 cost and rate impacts to retail providers relative to Accelerated Policy Case (assuming $30/tonne auction price), updated for v.3b



In general, all of the cap and trade policies analyzed here result in higher costs and rates for the all of the retail providers, regardless of which policy is pursued. This is because the GHG price is expected to increase the market clearing price for electricity, and these costs will be passed through to customers. However, if no auction revenue is returned to utilities, the rate impacts are likely to be highest. In this analysis we assume that when auction revenue is returned to retail providers it is used to reduce utilities' revenue requirement.

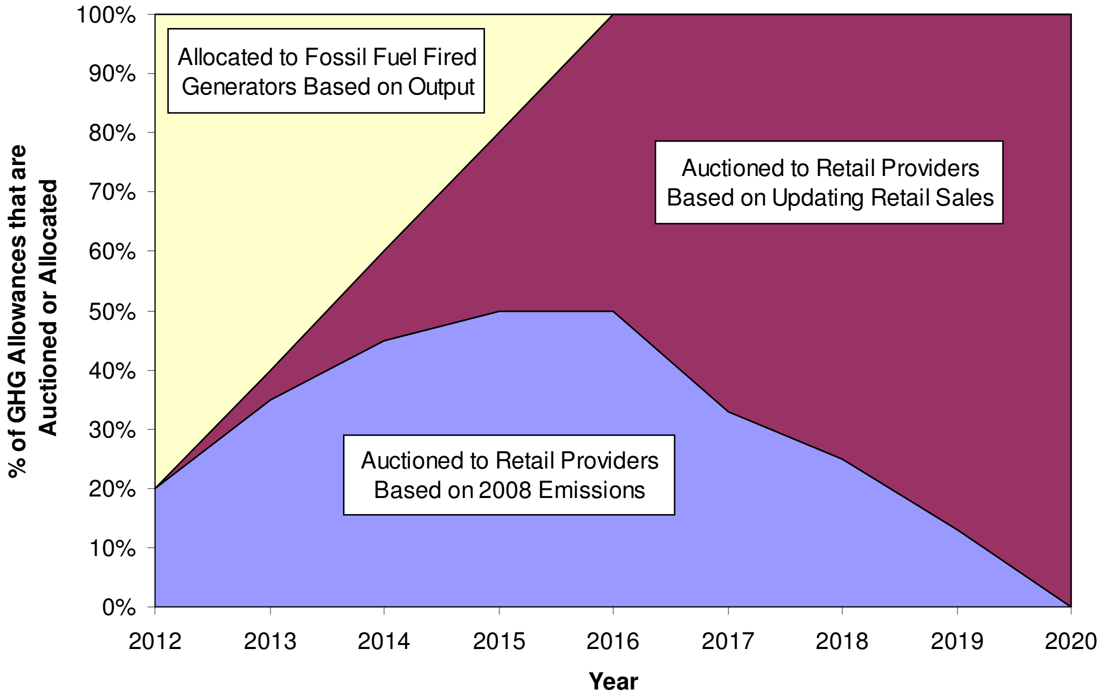
It is possible that a policy could be developed whereby auction revenues that are returned to retail providers could be ear-marked for other purchases besides rate-impact mitigation. Auction revenues could be earmarked for additional spending on renewable energy above baseline RPS targets, or for energy efficiency above stated efficiency targets. However, given that money is fungible, it would be difficult to enforce any earmarking of auction revenues in practice. As a result, we did not analyze the impact of required spending of auction revenue in this analysis.

In analyzing various cap and trade allocation options, the CPUC and CEC considered a number of criteria. In their final joint decision on GHG regulatory policy options (D.08-10-037), the CPUC and CEC stated that a cap and trade allocation policy should minimize costs to consumers, treat all market participants equitably and fairly, and support a well-functioning cap and trade market, among other objectives.

The Final Decision recommends a cap and trade approach for the electricity sector that seeks to balance among these objectives. In the decision, in the initial years of the proposed cap and trade program, 80% of greenhouse gas allowances would be allocated for free to fossil-fuel generators, based on their fuel-weighted generation output. This allocation approach would be phased-out, such that by 2016, none of the allowances would be freely allocated and 100% of greenhouse gas allowances would be auctioned. The CPUC and CEC recommend that by 2020 retail providers should be allocated GHG allowances (which would then be auctioned to generators) based entirely on their current level of retail sales. The transition schedule from a combination of auction and administrative allocation policy choices to an auction which is closest to the Joint Decision recommendations is summarized in Figure 30 below.[37]

[37] The transition to full auctioning is based on the same transition schedule included in the Joint Decision. This transition schedule for the return of auction revenue was included in the Joint Decision for illustrative purposes and does not represent a formal recommendation by the Commissions. While the Commissions recommended that all auction revenue be returned to retail providers, the Joint Decision did not provide a specific rate of transition from auction revenue return based on historical emissions to auction revenue return based on sales.

Figure 30. Joint Decision Proposal for Transition Schedule from GHG Allowance Allocation to Auction



In their final decision, the CPUC and CEC concluded that this relatively rapid transition from a partial administrative allocation to a full auction is preferred. The initial free allocation of allowances to generators on a fuel-differentiated basis would mitigate economic harm to, "the range of market participants in the electricity sector, including customers, retail providers, and deliverers" in the early years of the cap and trade program. In addition, the decision finds that, "Distributing some free allowances to deliverers would reduce short-term impacts on generating resources, and would help generators adapt to the new regulatory environment." [38] The decision also recommends transitioning to an auction relatively rapidly, in order to, "preclude windfall profits from allowance rents to independent deliverers."[39]

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[38] CPUC Decision 08-10-037 in Rulemaking R.06-04-009, Findings of Fact, paragraphs 31 & 35, pg. 288 – 289.

[39] CPUC Decision 08-10-037 in Rulemaking R.06-04-009, Findings of Fact, paragraph 30, pg. 288.

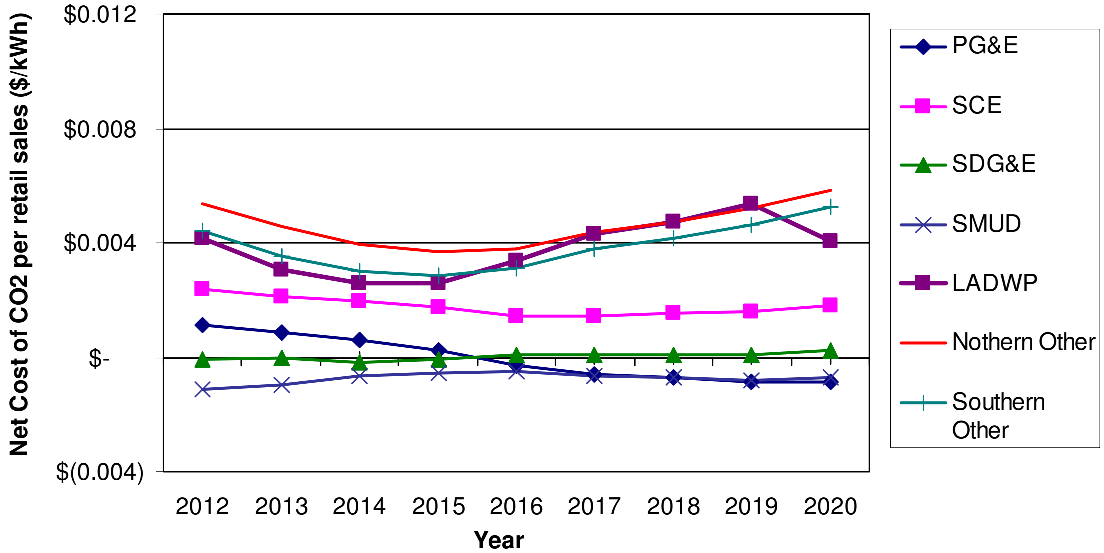
Many combinations of different cap and trade policy options were evaluated in the GHG Modeling proceeding and presented to stakeholders. Some options are more economic for lower-carbon retail providers, while other options are more economic for higher-carbon retail providers. In the GHG Calculator, E3 created a scenario reflecting as closely as possible the recommendations of the CPUC and CEC in the final Decision 08-10-037. However, the GHG Calculator is not designed to model fuel-differentiated output-based allocation, so this recommendation is not reflected below. The impacts to retail providers of the cap and trade allocation transition scenario described above are shown in Figure 31 below.

For simplicity, we assume that the market clearing price of CO_2 allowances is $30/tonne between 2012 and 2020. The assumed CO_2 price affects the overall magnitude of cost and rate impacts due to cap and trade policies, but does not impact the relative effects of different policies between retail providers. In all years of the program, compliance costs are lowest for the low-carbon intensive retail providers, including PG&E, SMUD and SDG&E, and highest for higher-carbon intensive retail providers. This outcome is consistent with the CPUC/CEC's judgment that, "equity dictates that we move to a market in which the 'polluter pays.'"[40]

In the early years of the cap and trade program a high percentage of electricity sector allowances are allocated for free to generators based on the "fuel differentiated output" criteria. Output based allocations of GHG allowances are especially beneficial to retail providers that are assumed to have a high proportion of utility-owned, or long-term contracts with fossil-fuel based generators in 2020, such as SMUD and SDG&E.

[40] CPUC Decision 08-10-037 in Rulemaking R.06-04-009, pg. 146.

Figure 31. Rate impact to retail providers over time of $30/tonne cap and trade program, using the allocation transition policy scenario shown in Figure 30 and Accelerated Policy Case assumptions ($/kWh, 2008 dollars), updated for v.3b



The fuel-differentiated output based allocation may also have the potential to mitigate windfall profits to generators through allowance rents. Some researchers have theorized that an output-based allocation will help to limit increases in wholesale electricity prices by providing generators with an incentive to increase their output. This is because under the output based allocation policy, generators only receive GHG allowances in proportion to the power they produce.[41]

The argument that an output-based allocation could help to mitigate increases in wholesale electricity prices was deemed "somewhat persuasive" in the Joint Decision, although this outcome is not relied on as a criteria for endorsing the output-based allocation method in the early years of the cap and trade program.[42] Indeed, electricity markets are not perfectly competitive, and the inclusion of a market value for CO_2

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[41] Fisher, Carolyn and Alan Fox, "Output-Based Allocations of Emissions Permits: Efficiency and Distributional Effects in a General Equilibrium Setting with Taxes and Trade," Resources for the Future Discussion Paper, December 2004, RFF DP 04-37.

[42] CPUC Decision 08-10-037 in Rulemaking R.06-04-009, pg. 211.

emissions may still lead to some wholesale market price increases. A more detailed analysis of actual market function, as well as impacts on existing and new long-term power contracts, would be necessary to evaluate the ultimate impact of an output-based allocation on market prices.

6.6 Concluding Notes on Cap and Trade

The impacts of a cap and trade policy on California's electricity sector could have important distributional impacts to the state's retail providers, as well as to electricity producers and consumers. A carefully designed cap and trade program will need to balance the multiple, competing policy objectives laid out in the Joint Decision. These objectives include minimizing costs to consumers, treating all market participants equitably and fairly and supporting a well-functioning cap and trade market, among others.

There are several key policy choices that could help to ensure that as many of the Joint Decision's stated objectives are met. This analysis has highlighted some of the distributional impacts of different policy choices on the state's retail providers. While some policy choices are beneficial to lower-carbon intensive retail providers, other policies are more beneficial to higher-carbon intensive retail providers. In all cases, we find that retail providers that own low-carbon generation resources are better off under a cap and trade policy than are the retail providers that are more exposed to market purchases.

Some of the key policy choices, which policymakers will need to consider as they design a cap and trade program include:

- ***The rate of transition to an auction-based allocation mechanism from various allowance allocation approaches.*** Assuming that the goal of a cap and trade program is to end up with a system where the "polluter pays", an auction is the best way to ensure that this objective is met. Higher emissions generators benefit from an historical emissions-based allocation. As expected, and desired, the introduction of an auction in a cap and trade policy environment benefits cleaner generators. The question then becomes, how quickly can the electricity sector adapt to new market rules where the GHG emissions polluter pays? The Joint Final Decision concludes that a transition period of four years (2012 – 2016) from a free allocation to an auction is an appropriate transition period.

- ***The use and allocation of auction revenues, and how this changes over time.*** Auction revenues could represent a significant revenue source for the government, depending on the final price of GHG allowances. Auction revenues, or auction revenue rights, could be distributed in an almost unlimited number ways, for any number of purposes. This analysis has shown that if auction revenue rights are not returned to electricity consumers, their costs and rate impacts will be high, and will increase in proportion to the price of GHG emission allowances. However, even a full refund of auction revenue rights to electricity consumers cannot mitigate all cost impacts.

Other key policy choices, which we have not investigated as part of this analysis but which deserve further investigation include the degree to which offsets are allowed to meet GHG allowance obligations and what types of offsets are allowed what conditions. Another important consideration is which sectors of the economy are to be included in the cap and trade market, under what timeframe and under what conditions.

7 Conclusion

In passing the Global Warming Solutions Act of 2006, California took a firm step towards reducing its greenhouse gas emissions, and towards developing the expertise and knowledge of how to implement a comprehensive, multi-sector greenhouse gas reduction strategy. These lessons and early actions in implementing GHG reductions in California have already influenced energy policy at the federal level.

For example, in mid-2009, the U.S. Environmental Protection Agency granted California permission to implement stricter vehicle emissions standards than are currently required under federal law, effective immediately. These vehicle standards are a critical component of the state's overall strategy to reduce GHG emissions and achieve the goals in AB 32. As a result of California's efforts on this front, thirteen other states and the District of Columbia plan to implement similar standards. In addition, the EPA and the U.S. Department of Transportation are developing compatible federal GHG emissions standards and fuel economy standards.

California's experience in developing, analyzing and implementing policies to reduce greenhouse gas emissions from the electricity sector has applicability for GHG policymaking in other regions and arenas as well. This analysis has shown that achieving significant greenhouse gas reduction policies in the electricity sector may be possible to achieve with manageable cost and electricity rate increases. Achieving high levels of energy efficiency turns out to be the most critical element in keeping GHG compliance costs at manageable levels, by reducing emissions directly and by reducing the amount of more expensive renewable generation that must be purchased to meet the state's RPS goal.

This analysis also finds that electricity sector costs are likely to increase between 2008 and 2020 regardless of what policy options are pursued. This is due to increasing costs of generation of all types. However, this analysis does not find a huge GHG emission reduction benefit from a cap and trade policy in California's electricity sector. It is possible that significant technology breakthroughs in the electricity sector could make a cap and trade policy more effective, by lowering the price point at which low-carbon generation options can effectively compete with conventional fossil-fuel generation. However, in general, we find that direct support and policies to encourage low-carbon generation and energy efficiency are likely to have a bigger, more direct impact on transforming the electricity sector than a cap and trade policy.

While this study has highlighted some key considerations of cap and trade policies in the electricity sector, many of the multi-sector cap and trade and emission reduction policies have not been analyzed in depth and remain poorly understood. One particularly relevant area for multi-sector analysis is the relationship between the transportation sector and the electricity sector, as electric vehicles mover closer to commercialization. How the transportation sector, and especially electric vehicles, will affect a future cap and trade market remains an important area for future research both in California and at the federal level.

As part of currently proposed federal energy legislation, cap and trade policy choices are currently being debated in Washington D.C. The Senate committees are working to develop an energy and climate bill to complement the bill that was recently passed by the House of Representatives, the "American Clean Energy and Security Act" of 2009 (H.R. 2454). These developments at the federal level raise the stakes for California, because California will want to ensure that a federal program represents a desirable approach for the state, especially if the federal program supersedes the cap and trade program under development in California.

Many of the issues that this report has identified regarding the distributional impacts of different cap and trade policies on California electricity retail providers are also applicable to a national analysis, where states and regions are important players. California as a whole is a relatively low-carbon state compared to the rest of the nation, with a relatively high share of utility-owned generation compared to many de-regulated jurisdictions in the East. These state and regional electricity sector differences are already playing a large role in the climate policy negotiations. As a result, it is important for all parties to have a clear, analytically supported basis upon which to evaluate policy choices.