NAVIGANT

Preliminary Assessment of Regulatory Cost Drivers in California's Energy Market

Prepared for:
Californians for Affordable and Reliable Energy

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1. Executive Summary

This is an extremely dynamic time in the California energy industry. Electricity providers are facing new generation, transmission, and distribution infrastructure needs, aggressive renewable energy and emissions goals, and increasingly complex, multifaceted, and multi-jurisdictional policies and regulations, all while striving to maintain reliable and affordable service. Additionally, transportation fuel providers will have to meet stringent carbon intensity limits. As the goals and objectives of these policies and regulations mature from legislation to implementation, they are beginning to introduce additional and potentially substantial costs to the California energy industry.

Energy costs in California are expected to increase sharply in the next several years as a result of several contributing factors. In particular, the cost of providing electricity service to California ratepayers is projected to increase at a more significant pace compared to historical rate increases. These cost increases are based on several factors – some of which are necessary to maintain reliable service to retail customers. These include the need to modify and/or replace an aging generation fleet, upgrade distribution systems and modify or expand electrical transmission systems. However, there are direct and indirect energy system costs primarily attributable to specific California policies focused on greenhouse gas ("GHG") reduction and other environmental objectives.

These regulations and policies will impact the costs of providing electricity service in California through:

1. Altered generation resource portfolios;
2. New transmission delivery requirements for remote, intermittent resources;
3. GHG mitigation costs associated with the environmental impacts of conventional electricity generation;
4. Costs associated with additional generation, storage, or demand-side programs to address intermittent resource integration issues; and
5. Necessary expansion and/or modification of distribution systems to accommodate an expected increase in distributed generation.

Regulatory requirements to lower the carbon intensity of fuels in California will also introduce uncertainties associated with additional costs in the production of transportation fuels, as well as the associated costs of infrastructure development and/or modifications needed for compliance. Specifically, there are substantial levels of uncertainties associated with:

- The ability of industry to significantly reduce the carbon intensity ("CI") values of alternative fuels, and to produce, distribute, and dispense them at an adequate retail scale to support compliance consistent with the current Low Carbon Fuel Standard ("LCFS") compliance schedule;
- The ability of fuel providers to adapt to reduced demand for gasoline and diesel fuels;
- The pace at which California drivers will purchase and use flexible-fuel vehicles, and the ability of industry to manufacture and integrate the needed engine technologies capable of running on alternative fuels;

- The rate at which compliance credits associated with alternative fuel consumption and sales can be generated to offset the deficits that will be incurred when consuming and selling (i.e. replacing) conventional gasoline and diesel; and
- Overall economic impacts to the fuels industry.

The cumulative effect on energy costs (electricity and transportation fuels) is only beginning to be understood by those most affected, which speaks to the need for a more informed dialogue. The intent of this paper is to therefore initiate a dialogue for understanding these costs, their direct and indirect effects on energy prices and reliability, and their more overarching effects on the ability of energy providers and other affected stakeholders to implement them responsibly while providing and receiving affordable energy. To meet this intent, this paper includes the following key objectives:

- Informing the public, policy makers, regulatory agency personnel, and the business community regarding some of the potential costs associated with energy-related policies and regulations;
- Providing a high-level understanding of the issues associated with these costs;
- Communicating retrospective and projected trends in energy costs and their impacts;
- Initiating a dialogue among key stakeholders regarding these costs, the accompanying issues, and their potential effects on California's energy industry; and
- Identification of those important issues that compel more detailed research and analyses that will serve to support this dialogue and assist California in meeting its overall policy objectives in as economically efficient and reliable a manner as practical.

Achievement of the objectives listed above will require an unbiased approach focusing on existing and credible information that can strongly support a comprehensive dialogue regarding these important issues. The analysis conducted in this paper therefore provides foundational information supporting three important points associated with these cost increases affecting California energy and electricity prices, most notably:

1. The price of California energy and electricity across all sectors combined (residential, commercial, industrial, and transportation) is notably higher than comparable prices in the neighboring states of Arizona, Nevada, Oregon, and Washington as well as the U.S. average;
2. Electricity price increases that have historically trended *lower* or near than the consumer price index ("CPI") since 1990 are forecast to increase through 2020 at percentage rates *exceeding* the CPI; and
3. While residential and commercial load growth has increased by an average 32 and 36 percent respectively since 1990, industrial load growth has decreased by over 17 percent.

This paper preliminarily identifies key drivers and areas of uncertainty associated with these three key points, as demonstrated by the potential costs to energy consumers arising from three high profile regulations related to Assembly Bill 32 ("AB 32"), also referred to as The California Global Warming Solutions Act of 2006. AB 32 requires

California to return to 1990 levels of GHG emissions by 2020. These targets are to be achieved through several specific regulations and policies directed at the energy industry.

We are in the early stages of implementing three key energy related policies that are the focus of this paper, namely the Renewable Portfolio Standard ("RPS") and other renewable requirements; (2) GHG cap and trade; and (3) the LCFS. Our preliminary examination of potential cost impacts of these regulations tell us the following:

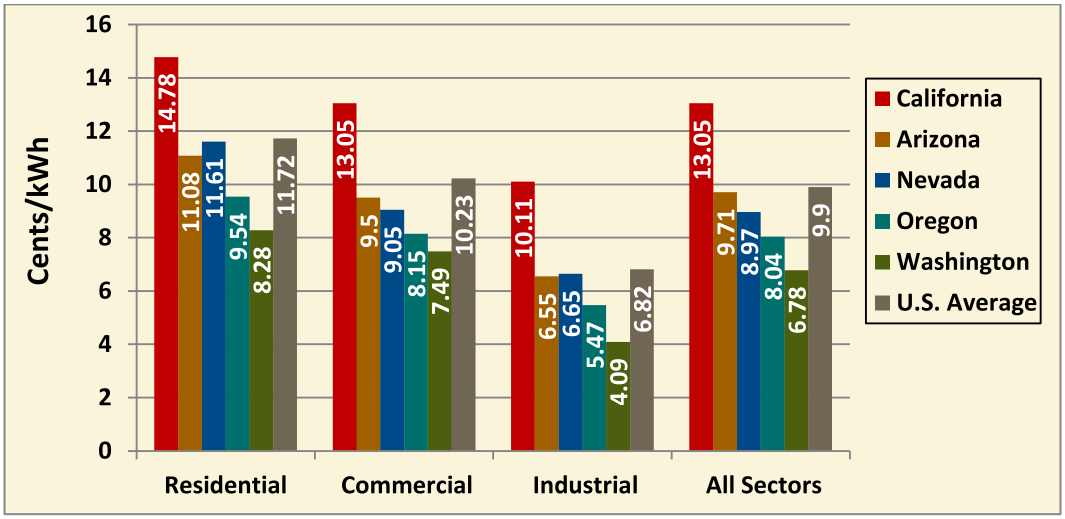
- The 33 percent RPS requirement will likely lead to increased prices and rates as utilities attempt to incrementally phase renewable energy into their portfolios. These incremental adjustments have already created challenges in the industry's ability to provide reliable electric service (e.g. integration; source-to-load transmission connections; etc.).
- Implementation has added to electricity prices attributable to the "carbon component" of energy costs. The California Independent System Operator ("CAISO") has indicated that wholesale bids of gas-fired capacity in 2013 are reflecting the additional costs of carbon. At current carbon prices, this can increase bids into the wholesale market between $6 and $10/MWh, depending on the efficiency of the plant. The impact that these carbon prices will have on electricity bills will differ for end-use consumers due to procedural rules regarding recycling of allowance auction revenue.
- The California Air Resources Board ("CARB") has assumed that full and rapid compliance with the LCFS will result in negligible increases in the price of gasoline and diesel. However, there appears to be considerable uncertainty on the eventual cost impacts as well as considerable litigation to date regarding the legality of the rule. This is compounded by uncertainty regarding the potential supply of alternative fuels and associated infrastructure required for compliance.

As an introduction to these costs, drivers, and uncertainties, this paper shows where energy costs and rates have trended historically, some of the uncertainty regarding their future levels, and their likely drivers. The costs associated with new policies will arise from the need to alter generation and transmission resources needed to comply with these policies and regulatory requirements, along with several other related drivers. Introduction of these costs, the changes they necessitate to resource portfolios, and the accompanying operational complexities are also beginning to show signs that they could adversely affect future grid reliability.

Energy Prices in Neighboring States

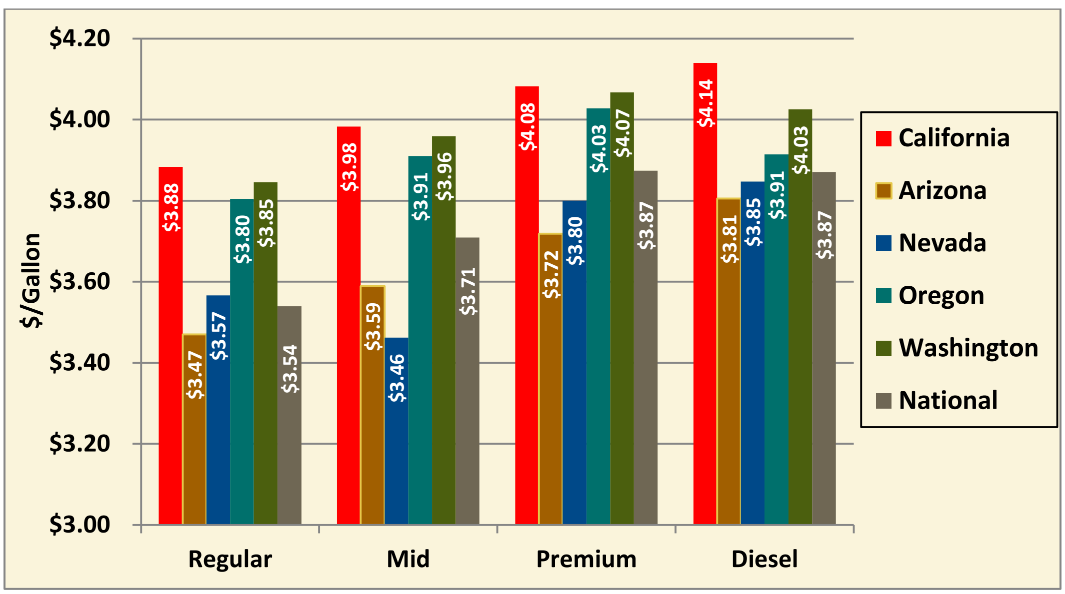
While some load growth reductions can be attributed to higher levels of energy efficiency, other added costs can exacerbate an existing problem of businesses leaving the state for other, lower energy-cost states, as suggested by Figures ES-1 and ES-2 that compare electricity rates and gasoline prices in California to other Western States and the U.S. as a whole.

Figure ES-1: 2011 Average Retail Electricity Price



Source: U.S. Department of Energy – Energy Information Administration. *2011 Average Retail Electricity Price for Bundled and Unbundled Customers.*

Figure ES-2: Gasoline Prices – July 2013



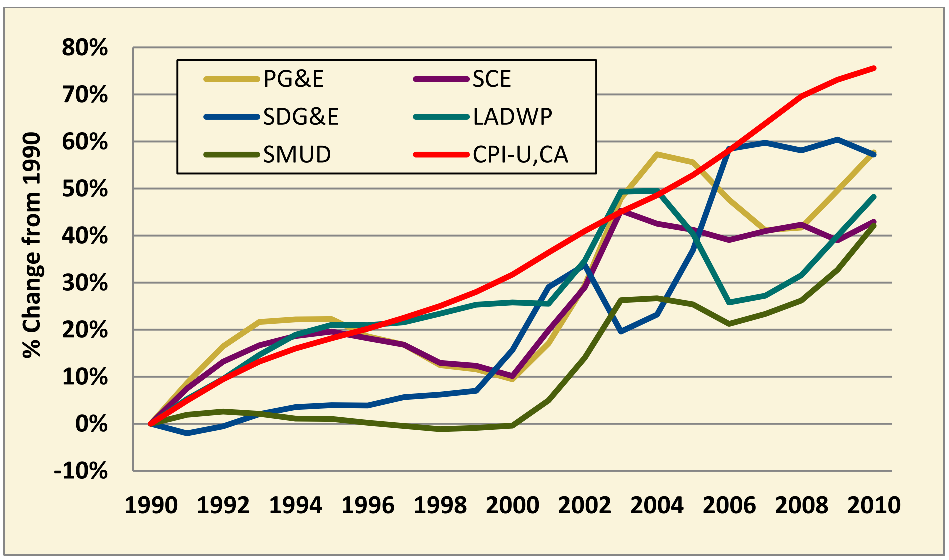
Source: American Automobile Association. *AAA Gauge Fuel Report. National Average Prices*. August 2013.
Note: The disparity in gasoline prices is not a result of the LCFS currently.

The difference in energy costs between California and neighboring states creates impacts not just to industry in California. Fuel and electricity price differences can also have impacts on local communities in the form of increased costs for city or county vehicle fleets, heating and cooling costs for schools and hospitals, electricity costs at water treatment facilities, and costs for providing other essential services.

Electricity Price Increases

Over the past 20 years, California's electric utilities have increased electricity rates at a pace that was below the CPI for California. The following graph illustrates the percentage rate increase for California's five largest utilities since 1990.[1] These utilities include California's three largest investor-owned utilities: Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and the San Diego Gas and Electric Company ("SDG&E"); along with the two largest publicly-owned utilities ("POUs"): the Los Angeles Department of Water and Power ("LADWP") and the Sacramento Municipal Utilities District ("SMUD").

Figure ES-3: 3-year Average Retail Electricity Prices, Percent Change from 1990



Sources: California Department of Finance Financial & Economic Data Website; CPI Calendar Year Averages from 1950, http://www.dof.ca.gov/html/fs_data/latestecondata/documents/BBCYCPI_010.xls
California Energy Commission. *Electricity Statistics and Data Website; http://energyalmanac.ca.gov/electricity/Utility-Wide_Average.xls*

As illustrated in Figure ES-3, all five of California's largest utilities have seen their respective system average rates increase at a rate below CPI since 1990. The utilities did experience significant rate increases as a result of the 'electricity crisis' in 2001, and the subsequent increase in natural gas prices through the early 2000s. This resulted in some of the utilities experiencing average rate increases near or slightly above CPI from 2001-2010, but all of the five major utilities have been below CPI on the 20-year average.

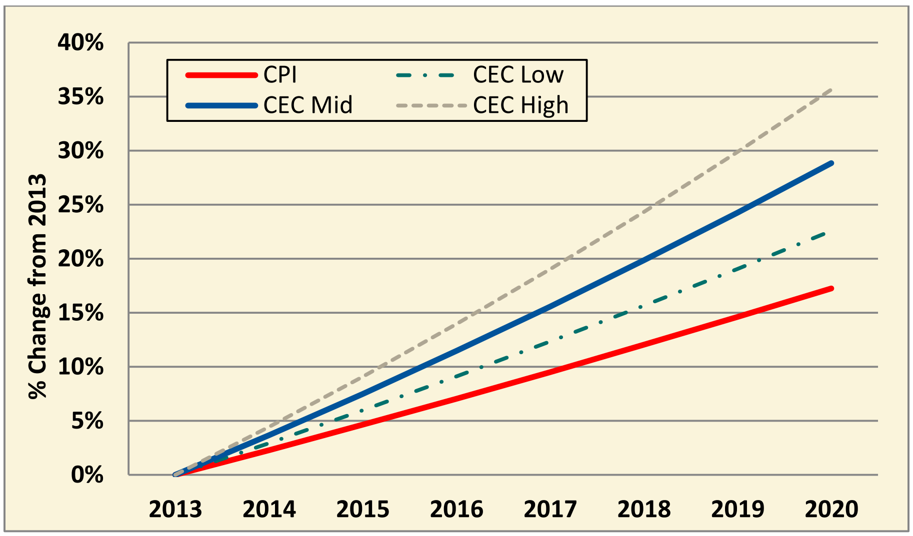
This trend will not continue for the remainder of this decade. As shown on the following chart, system average rates are expected to increase at a pace well in *excess* of CPI through 2020. Figure ES-4 provides three ranges for potential rate increases from a recent

[1] We utilized a three-year rolling average to provide for a 'smoothing' out of the rate changes.

report by the California Energy Commission ("CEC") and shows that under one of the CEC's scenarios system average rates could be as much as double the forecasted CPI.[2]

It is important to note that this forecast of future rates may in fact be conservative as it appears to indicate that a major driver is the beginning of cap and trade. Other cost pressures on California's utilities (including RPS costs) may result in rate increases greater than the CEC forecast.

Figure ES-4: CEC Forecasted System Average Rate Increases Compared to CPI



Source: Source: CPI, Survey of Professional Forecasters, Federal Reserve Bank of Philadelphia, March 10, 2013 and California Energy Demand 2014-2024 Preliminary Forecast Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, p.34, California Energy Commission, May, 2013

Electricity Load Growth and Evolving Customer Base

Over the past two decades California's total electricity demand has increased by an average annual amount of 0.8 percent.[3] This load growth has not been consistent across all customer classes. Changes in the composition of the overall California load being served are evident when examining annual and cumulative percentage load growth changes by sector from 1993 through 2011 (Figure ES-5). The four sectors for which CEC data were available include residential, commercial, industrial, and other.[4]

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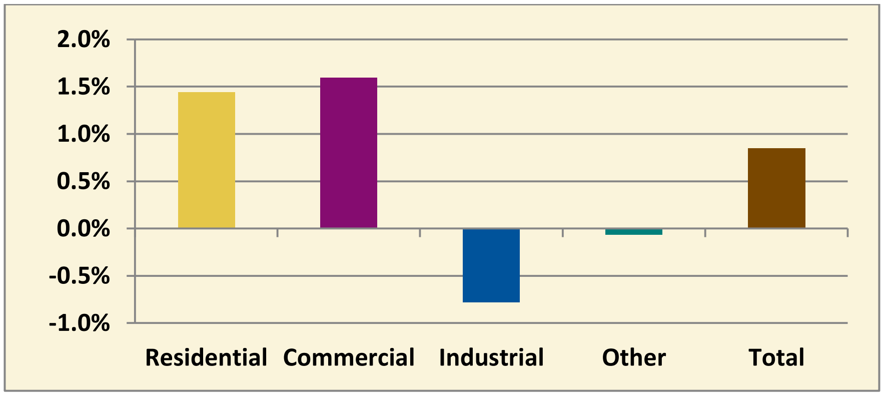
[2] *Source: Source: CPI, Survey of Professional Forecasters, Federal Reserve Bank of Philadelphia, March 10, 2013 and California Energy Demand 2014-2024 Preliminary Forecast Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, p.34, California Energy Commission, May, 2013.*

[3] Actual demand in California peaked in 2008 and has yet to return to pre-recession levels.

[4] The other category includes the remaining load attributable to agricultural and other water pumping load, mining, construction, and streetlights.

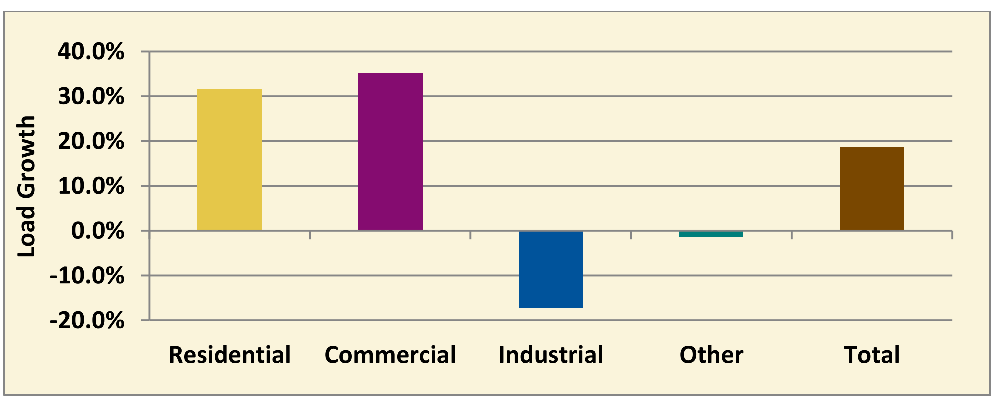
Figure ES-5: Compounded Average Annual Load Growth - Percentage Change by Sector; 1993-2011



Source: California Energy Commission. *Energy Consumption Data Management System, Electricity Consumption by Entity Website;* http://www.ecdms.energy.ca.gov/elecbyutil.aspx

Over the past 18 years, the total average annual increase in load growth across all four sectors has been approximately 0.8 percent. While residential (1.4 percent) and commercial (1.6 percent) classes saw steady load growth during this period, industrial load peaked in 2000 and has declined (-0.8 percent) over the period examined. (Figure ES-6). Cumulative growth in residential (31.7 percent) and commercial (35.1 percent) loads over the past 18 years were similarly offset by reductions in industrial (-17.1 percent) and "Other" (-1.4 percent) loads (Figure ES-7).

Figure ES-6: Cumulative Load Growth - Percentage Change by Sector; 1993-2011



Source: California Energy Commission. *Energy Consumption Data Management System, Electricity Consumption by Entity Website;* http://www.ecdms.energy.ca.gov/elecbyutil.aspx

Changes in the composition of California's load – primarily the shift in industrial load that previously comprised over 20 percent of total load in 1993 to less than 15 percent in 2011 can place additional costs and operations requirements on California's utilities.

Issues and Considerations for California's Energy Future

Increases in California energy costs will be absorbed by all Californians, including local communities. Government services such as fire and police will likely be impacted by increasing fuel and electricity costs. Schools, hospitals, water treatment facilities and other local services will also face higher energy costs that must be addressed by decision makers facing budget challenges.

In addition to the important points and objectives presented above, the analysis and findings of this paper also indicate that:

- The complexity associated with simultaneously implementing several transformative policies and regulations within an already complex and increasingly costly energy landscape in California can lead to unintended consequences. These consequences may include, but are not limited to:
    - Decreasing reliability of the electrical grid associated with increasing grid complexity;
    - Rapid transformation of utility business models;
    - Stranded costs; and
    - Incremental reductions in in resource planning flexibility.
- Improved data, analysis and information are needed as legislators and regulators consider the future direction of energy policy in California. This is a major finding of this paper. There is not a single, credible source of analytics and data that can inform companies and policymakers regarding the cumulative costs of recent energy related policies and regulations.
- Electricity costs are projected to increase at a rate higher than the historical trend. This can contribute to a wider disparity in energy costs between California and other Western states going forward. Californian's recognition regarding the actual electricity costs associated with these policies and regulations is in many respects "softened" by a combination of low natural gas prices and the early stages of the ramp up of the renewable portfolio standard to 33 percent;
    - Current RPS costs reflect older renewable facilities that tend to be at lower costs than future renewable projects (mostly "Qualifying Facilities" under the Public Utilities Regulatory Policy Act of 1978 "PURPA").
- While some administrative efforts have been made to limit the cost impacts of these regulations on select classes of energy consumers, such efforts will lead to considerable complexity with respect to estimating the likely cost impacts of these regulations for specific commercial and industrial consumers.

It is essential that California legislators, regulators, policy, and decision makers recognize that substantial costs are being added to the California energy system. While there are likely to be tangible environmental and health benefits associated with these policies and regulations, it is also important to recognize the cumulative costs involved and account for them when considering development of further regulations and laws affecting the statewide energy industry.

This paper is therefore a first step towards understanding the cost and implications of recent energy-related regulations through the lens of three specific energy related regulations. At a higher level, there is a recognized need for coordination and broad-based planning that brings all key stakeholders together into a discussion surrounding the appropriate path toward meeting the overarching public policy goals adopted and under consideration by California while maintaining a reliable energy system at reasonable costs.

The lack of a comprehensive, detailed analysis of the cumulative costs of recent energy-related policies and regulations places a significant amount of uncertainty on the California energy market.

2. Introduction

This is an extremely dynamic time in the California energy industry. Electricity providers are facing new generation, transmission, and distribution infrastructure needs, aggressive renewable energy and emissions goals, and increasingly complex, multifaceted, and multi-jurisdictional policies and regulations, all while striving to maintain reliable and affordable service. Additionally, transportation fuel providers will have to meet stringent carbon intensity limits. Table 2-1 highlights some of the energy-related regulations that have been passed recently in California.

Table 2-1: Examples of California's Recently Passed Energy Regulations

Recent Existing State Mandates	
Renewable Portfolio Standard (33 % RPS)	Feed in Tariffs (FIT)
AB 32 Regulations (e.g. Cap and Trade)	Renewable Auction Mechanism (RAM)
Once-Through Cooling (OTC) Policy	Net Energy Metering (NEM) – AB 920
California Emission Performance Standards - SB 1368	Energy Efficiency – AB 2021
Mandatory Greenhouse Gas Emissions Reporting Regulation (MRR)	Waste Heat and Carbon Emissions Reduction Act – AB 1613, AB 2791
California Solar Initiative (CSI)	Resource Adequacy – AB 380
New Solar Homes Partnership (NSHP)	Energy Storage – AB 2514
Solar Incentive Program – SB 1	Smart Grid Deployment – SB 17
Self-Generation Incentive Program (SGIP)	AB 32 Administrative Fee

Source: Navigant Consulting, Inc. (unpublished))

Many of these new regulatory requirements are focused on improved air and water quality. Environmental regulations have been present in the energy industry for decades, and continue to be passed at the federal and state levels in response to the public's concerns regarding climate change, greenhouse gas ("GHG") emissions, and a range of other air, land, and water quality issues.

The most prominent of these regulations have been developed in response to California's groundbreaking GHG mitigation law, The Global Warming Solutions Act of 2006, commonly referred to as AB 32. AB 32 requires California to return to 1990 levels of GHG emissions by 2020. These targets are to be achieved through several specific regulations and policies directed at the energy industry.

It is important to note that AB 32 as a law only sets GHG reduction targets and timetables. It does not identify specific regulations and other measures to achieve these targets. Rather, it instructs the California Air Resources Board ("CARB") to coordinate with other state agencies to develop a suite of regulatory measures to achieve the targets. Those regulatory measures are highlighted in Table 2-2. If successful, these regulations will produce meaningful GHG reductions and represent a significant accomplishment by mitigating California's contribution to the some of the adverse environmental and economic impacts of climate change.

Table 2-2: Policies Included in AB 32 Scoping Plan (Page 105)

Existing Laws, Regulations, Policies and Programs
Light-Duty Vehicle Greenhouse Gas Standards (Pavley I)
Renewables Portfolio Standard (to 20 %)
Solar Hot Water Heaters
Million Solar Roofs
High Speed Rail
Measures Strengthening & Expanding Existing Policies & Programs
Electricity Efficiency
Natural Gas Efficiency
Renewables Portfolio Stand (from 20 % to 33 %)
Sustainable Forests
Light-Duty Vehicle Greenhouse Gas Standards (Pavley II)
Discrete Early Actions
Low Carbon Fuel Standard
High GWP in Consumer Products (Adopted)
Smartways
Landfill Methane Capture
High GWP in Semiconductor Manufacturing
Ship Electrification (Adopted)
SF6 in non-electrical applications
Mobile Air Conditioner Repair Cans
Tire Pressure Program
New Measures
California Cap-and-Trade Program Linked to WCI Partner Jurisdictions
Increase Combined Heat and Power
Regional Transportation-Related GHG Targets
Goods Movement Systemwide Efficiency
Vehicle Efficiency Measures
Medium/Heavy Duty Vehicles Hybridization
High GWP Reductions from Mobile Sources
High GWP Reductions from Stationary Sources
Mitigation Fee on High GWP Gases
Oil and Gas Extraction
Oil and Gas Transmission
Refinery Flares
Removal of Methane Exemption from Existing Refinery Regulations

Source: California Air Resources Board. Climate Change Scoping Plan: A Framework for Change. Pursuant to AB 32 The California Global Warming Solutions Act of 2006. December 2008.

The potential environmental benefits resulting from these policies are relatively well known to legislators and regulators. However, the associated costs are less clear, particularly when viewed from a broader perspective that includes the costs associated with several regulations and policies being implemented conjunctively (this point is highlighted in more detail in Section 3).

AB 32 will impact electricity rates primarily through two programs: limits on GHG emissions through a cap and trade program and statewide renewable energy targets. AB 32 will also impact transportation-related energy costs through requirements that fuel providers meet annual average carbon intensity ("CI") requirements that increasingly become more stringent to 2020.

Entities that are directly regulated under these directives will need to alter their resource portfolios, build new infrastructure, and pay for newly internalized costs of carbon pollution. These increases in production costs are almost always passed through to customers to some extent, inclusive of additional energy costs. Importantly, these added costs are not only associated with fossil fuels. New renewable energy requirements will lead to cleaner electricity and fuels, although these resources typically cost more to use on a per unit basis than conventional, fossil-based resources as well as requiring new transmission capacity. For energy consumers, this will likely lead to higher energy expenditures as these costs are absorbed and reflected in prices and rates paid for electricity, transportation fuels, and other carbon-based fossil fuels, mostly natural gas. Therefore, even those energy consumers that are not directly regulated under AB 32 will incur costs associated with compliance requirements that are reflected in energy costs.

While it is generally understood that the environmental benefits associated with AB 32 (and other regulations) will not be achieved without costs, Californians are increasingly concerned about the lack of information on the costs associated with achieving these environmental objectives. This paper addresses the potential cost and rate impacts on energy consumers from these policies and accompanying regulations by summarizing existing and public data and analyses that have attempted to quantify the costs associated with these policies and regulations. *However, it should be noted that this paper is not a comprehensive analysis of costs associated with AB 32.*[5] Additionally, there are also new regulatory requirements that fall outside of AB 32 that will likely place additional costs on the energy system, although it is outside the scope of this paper to assess all costs associated with all recently approved energy related regulations.

We have instead chosen to highlight the cost impacts – and associated uncertainty - of these regulations by focusing on three prominent energy-related regulations: (1) the Renewable Portfolio Standard ("RPS") and other renewable requirements; (2) GHG cap and trade; and (3) the Low Carbon Fuel Standard ("LCFS") as indicative of two broader themes emphasizing that:

1. While there are clearly costs associated with these regulations, their varying impacts on specific classes of energy consumers have not been sufficiently studied in detail. Where cost information and data do exist, the disparity and gaps in the results do not lead to a definitive conclusion regarding energy costs.
2. The cumulative and interactive aspects of the regulations do not appear to have been analyzed in depth, particularly in terms of identifying potential unintended consequences.

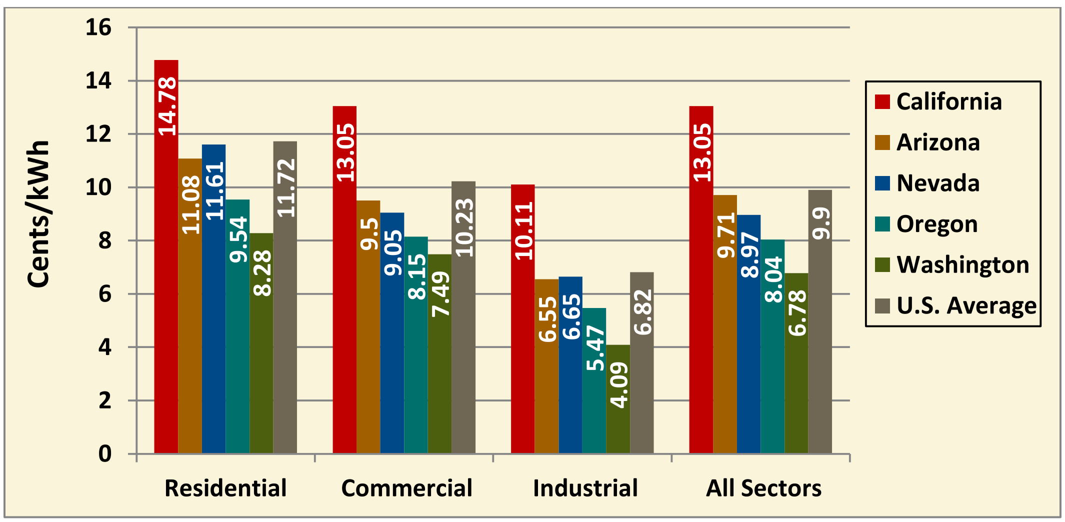
[5] This paper is not a comprehensive assessment of potential cost and rate impacts associated with these policies and regulations. An examination of the full suite of policies and regulations is outside the scope of this paper although this is something that requires further attention and analysis. Nor is this paper a cost benefit analysis. The potential and expected benefits resulting from recently passed regulations and policies have been communicated by policymakers and regulators, typically during the formative stages of the regulatory process. Nor does this paper address issues of energy efficiency and how price signals (e.g. electricity rates, carbon, etc.) can drive lower electricity consumption and lower energy bills.

The paper will highlight the underlying drivers of costs associated with these regulations and will point out where there is uncertainty in not only the magnitude of these costs but in how these costs may be absorbed by specific customer classes. The paper also discusses how the costs of these policies and regulations contribute to the ongoing disparity of energy costs in California compared to other Western states. The paper will conclude with an assessment of further analysis and data needed to provide objective and credible assessments of the likely cost and rate impacts associated with the regulations and policies considered herein.

3. Comparison of Energy Costs across the West

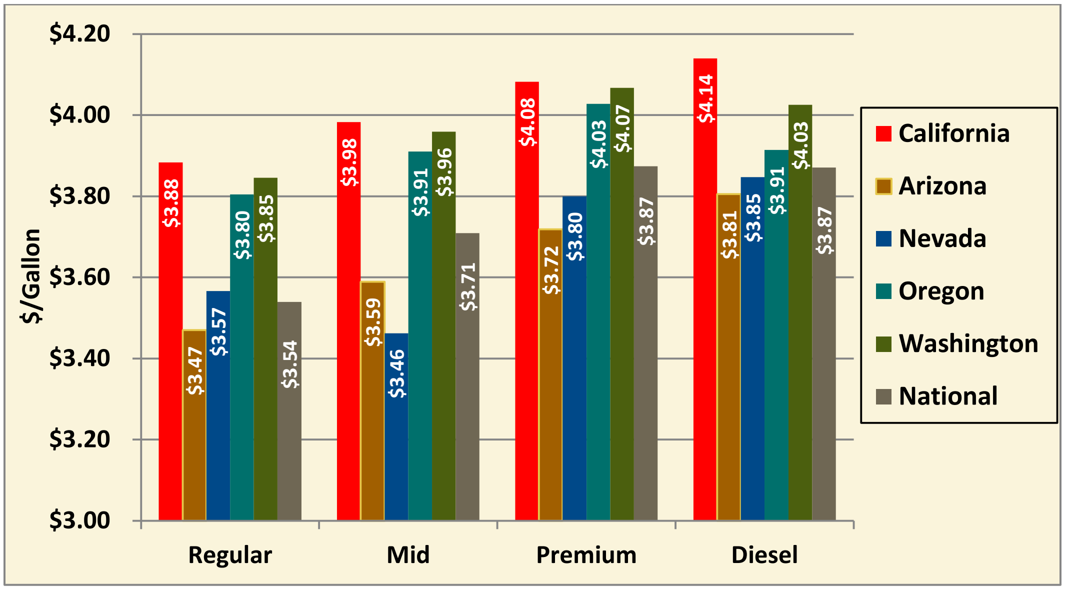
Any assessment of cost impacts associated with energy regulations should begin with an assessment of where California energy costs are currently. Figures 3-1 and 3-2 compare electricity rates and gasoline prices in California to other Western states. The price of California electricity across all sectors combined (residential, commercial, industrial, and transportation) is notably higher than comparable prices in the neighboring states of Arizona, Nevada, Oregon, and Washington. Additionally, gasoline prices are also higher than comparable states in the West. Both electricity and transportation fuel costs in California are higher than U.S. averages.

Figure 3-1: 2011 Average Retail Electricity Price



Source: U.S. Department of Energy – Energy Information Administration. *2011 Average Retail Electricity Price for Bundled and Unbundled Customers*.

Figure 3-2: Gasoline Prices – July 2013



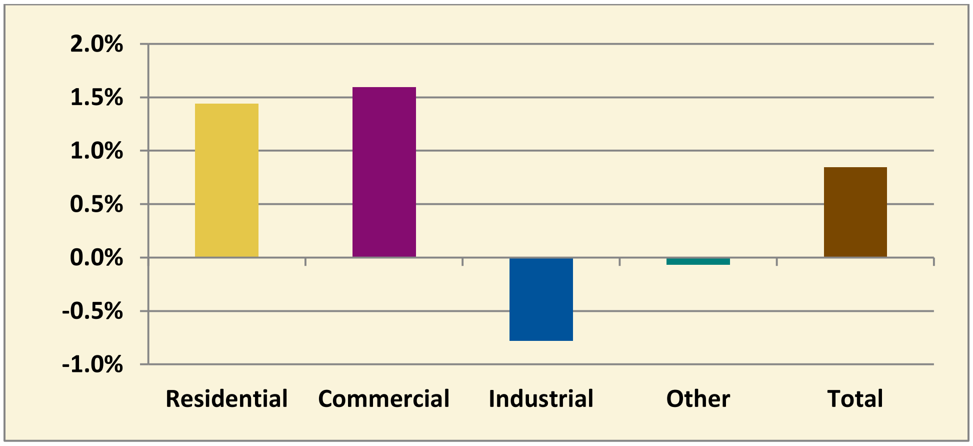
Source: American Automobile Association. *AAA Gauge Fuel Report. National Average Prices*. August 2013.
Note: The disparity in gasoline prices is not a result of the LCFS currently.

Over the past two decades California's total electricity demand has increased by an average annual amount of 0.8 percent.[6] This load growth has not been consistent across all customer classes. Changes in the composition of the overall California load being served are evident when examining annual and cumulative percentage load growth changes by sector from 1993 through 2011 (Figures 3-3 and 3-4). The four sectors for which CEC data were available include residential, commercial, industrial, and other.[7]

Importantly, while residential and commercial load growth has increased by an average 32 and 36 percent respectively since 1990, industrial load growth has decreased by over 17 percent.

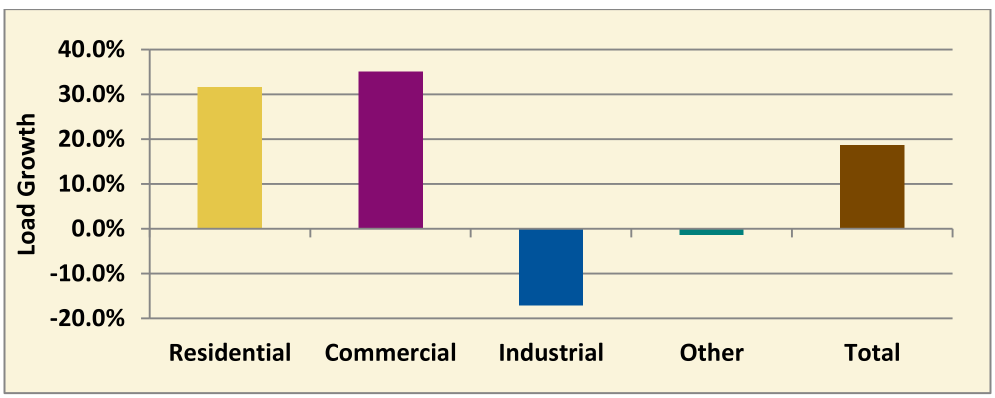
[6] Actual demand in California peaked in 2008 and has yet to return to pre-recession levels.
[7] The other category includes the remaining load attributable to agricultural and other water pumping load, mining, construction, and streetlights.

Figure 3-3: Compounded Average Annual Load Growth - Percentage Change by Sector; 1993-2011



Source: California Energy Commission. *Energy Consumption Data Management System, Electricity Consumption by Entity Website;* http://www.ecdms.energy.ca.gov/elecbyutil.aspx

Figure 3-4: Cumulative Load Growth - Percentage Change by Sector; 1993-2011



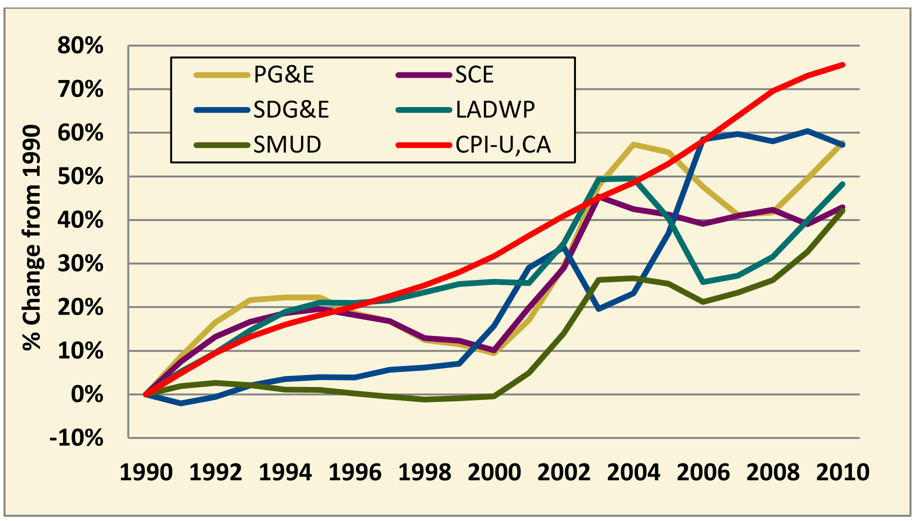
Source: California Energy Commission. *Energy Consumption Data Management System, Electricity Consumption by Entity Website;* http://www.ecdms.energy.ca.gov/elecbyutil.aspx

Changes in the composition of California's load – primarily the shift in industrial load that previously comprised over 20 percent of total load in 1993 to less than 15 percent in 2011 can place additional costs and operations requirements on California's utilities. This is because most industrial customers have load profiles that are more economic and reliable to serve than others customer segments.

4. Illustrative Impacts of AB 32 Regulations on Energy Prices[8]

Over the past 20 years, California's electric utilities have increased electricity rates at a pace that was below the CPI for California. Figure 4-1 illustrates the percentage rate increase for California's five largest utilities since 1990.[9] These utilities include California's three largest investor-owned utilities ("IOUs"): Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and the San Diego Gas and Electric Company ("SDG&E"); along with the two largest publicly-owned utilities ("POUs"): the Los Angeles Department of Water and Power ("LADWP") and the Sacramento Municipal Utilities District ("SMUD").

Figure 4-1: Utility-wide 3-year Average Retail Electricity Prices, Percent Change from 1990



Sources: California Department of Finance Financial & Economic Data Website; CPI Calendar Year Averages from 1950, http://www.dof.ca.gov/html/fs_data/latestecondata/documents/BBCYCPI_010.xls
California Energy Commission. *Electricity Statistics and Data Website; http://energyalmanac.ca.gov/electricity/Utility-Wide_Average.xls*

The utilities experienced a significant rate increases as a result of the 'electricity crisis' in the 2001 and the subsequent increase in natural gas prices through the early 2000s. This resulted in some of the utilities experiencing average rate increases near or slightly above CPI from 2001-2010, but all of the five major utilities have been below CPI on the 20-year average.

While these cost increases have tracked below CPI, retail rates do not seem to have benefited from declines in wholesale electricity prices since 2003. The past several years have seen a significant decline in wholesale electricity prices in California, and nationally as the cost of natural gas has reduced – driven by the development of unconventional

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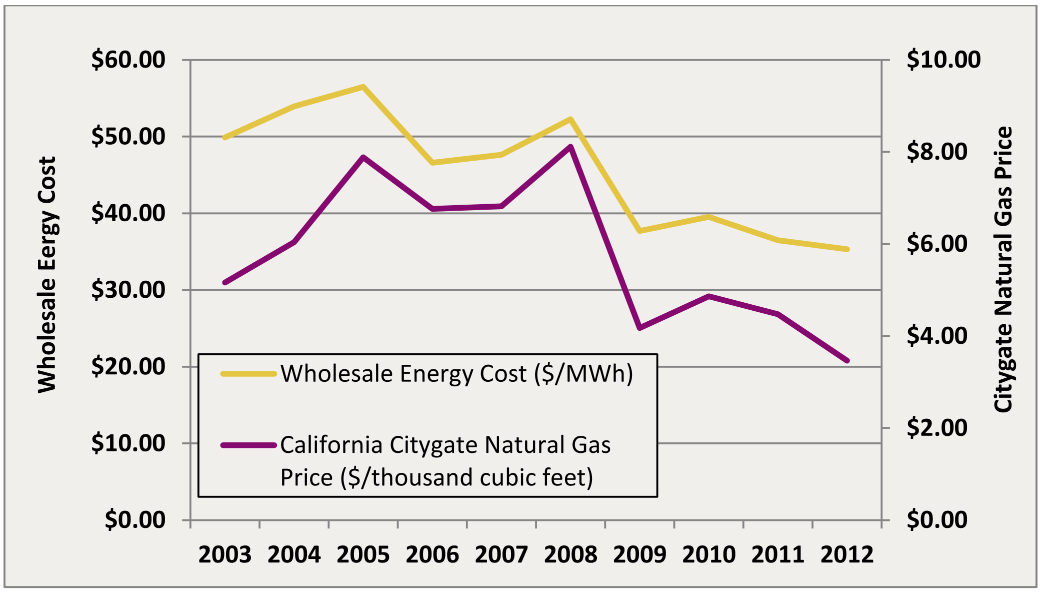
[8] Throughout this section, various data tables and charts are presented from third party reports. This paper does not normalize the data in terms of inflation base year. Where the data is sourced as being from Navigant, they are expressed in 2012 dollars. All other data are represented as they were in the respective reports.
[9] We utilized a three-year rolling average to provide for a 'smoothing' out of the rate changes.

natural gas (and oil) extraction in North America. Figure 4-2 illustrates the recent decline in natural gas prices in California. Without the significant reduction in natural gas prices, retail rates likely would be well above the levels seen today.

Figure 4-2: Natural Gas Prices and Wholesale Energy Costs – 2003 to 2012

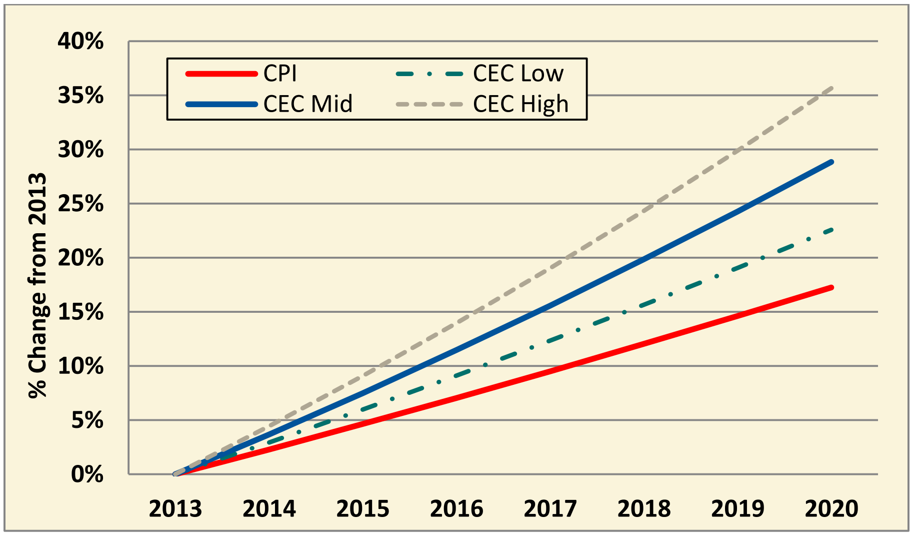


Sources: California Independent System Operator. *2007 Market Issues & Performance Annual Report, p 236*. April, 2008
California Independent System Operator. 2010 Market Issues & Performance Annual Report, Department of Market Monitoring. P. 59. April, 2011
California Independent System Operator. *2012 Market Issues & Performance Annual Report*. Department of Market Monitoring. P. 60. April 2013
U.S. Department of Energy – Energy Information Agency. *Natural Gas Citygate Price in California*. http://www.eia.gov/dnav/ng/hist/n3050ca3a.htm

This trend will not continue for the remainder of this decade. The cost of providing electricity service to California ratepayers is projected to increase significantly compared to historical rates of increase. As shown on in Figure 4-3, system average rates are expected to increase at a pace well in *excess* of CPI through 2020. The data for the chart comes from a projection by the California Energy Commission ("CEC") and shows that under one of the CEC's scenarios system average rates could be as much as double the forecasted CPI.[10]

[10] *California Energy Demand 2014-2024 Preliminary Forecast Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, p.34, California Energy Commission, May, 2013.*

Figure 4-3: CEC Forecasted System Average Rate Increases Compared to CPI



Source: CPI, Survey of Professional Forecasters, Federal Reserve Bank of Philadelphia, March 10, 2013 and California Energy Demand 2014-2024 Preliminary Forecast Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency, p.34, California Energy Commission, May, 2013.

These data and projections warrant an examination into why this is occurring. The remainder of this section provides a preliminary identification of the key drivers and areas of uncertainty of these potential cost increases for a select group of three high profile regulations under AB 32, namely the RPS and other renewable requirements, GHG cap and trade, and the Low Carbon Fuel Standard ("LCFS").

4.1 Renewable Portfolio Standard and Distributed Generation

With the passage of SB 1078 in 2002, California established one of the first RPS programs in the United States. The first iteration of the RPS had fairly a flexible market structure for meeting renewables targets. However, subsequent efforts to legislate updates to the RPS have increasingly placed more restrictions on how the state will meet its RPS targets. From 2008 – 2010, several legislative and regulatory efforts sought to expand the 20 percent RPS to a 33 percent RPS, including Governor Schwarzenegger's Executive Order S-14-08, Senate Bill (SB) 14 and CARB's subsequent "Renewable Energy Standard" proposal.

In 2011, the 33 percent RPS became law with the passage of SB 2 (1X). This law is far more prescriptive than its predecessors, placing significant limitations on how RPS compliance can be met. Importantly, SB 2 (1X) requires utilities to procure renewable resources in three procurement 'buckets' which prioritize in-state generation. Specifically, SB2 (1X) limits RPS compliance to the following:

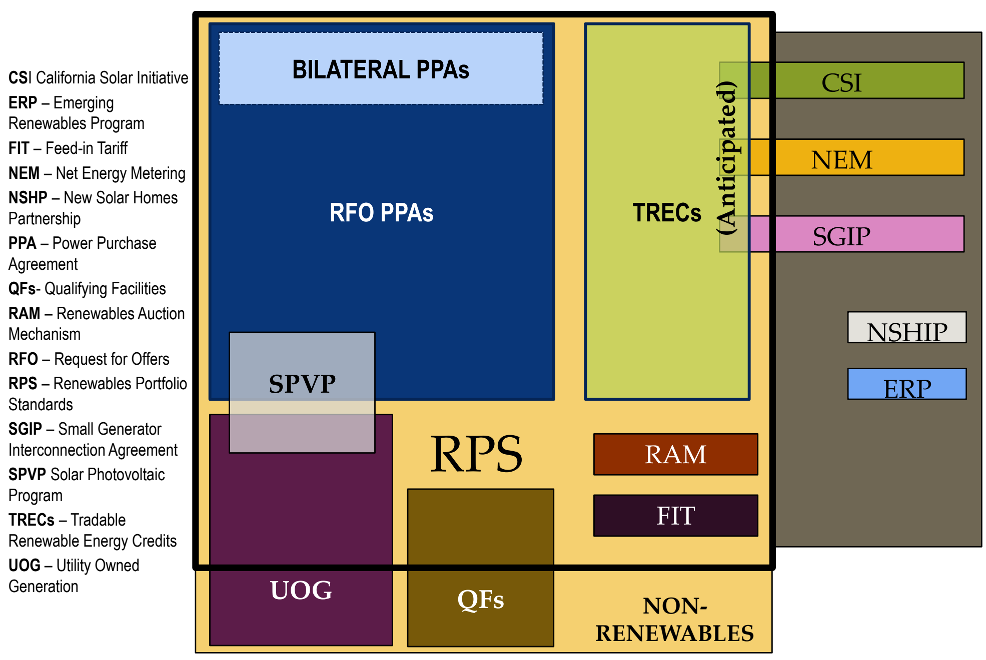
- <u>Bucket 1</u>: 50 percent minimum in-state, connected to California balancing authority or dynamically transferred, increasing to 75 percent minimum by 2020;
- <u>Bucket 3</u>: 25 percent maximum Renewable Energy Credits ("REC") or non-firm and shaped out of state ("OOS") resources, decreasing to 10 percent by 2020; and

- Bucket 2: Remaining are firmed and shaped contracts.

By increasing the amount of renewable generation needed for compliance and limiting the geographic flexibility for procuring this generation, SB 2 (1X) has created the potential for increased compliance costs by California utilities. The vast majority of contracts signed since SB 2 (1X) passed are Bucket 1 (in-state or claimed dynamic transfer). Bucket 2 contracts are mostly pre- SB 2 (1X) Pacific Northwest wind projects with delivery to California. Bucket 3 contracts are either REC-only to meet short-term compliance deficits, or OOS projects. Navigant's ongoing analysis of California's RPS progress indicates that while some California utilities have already procured a large percentage of their energy supply from qualifying renewable resources, others depend highly on newly contracted resources currently under development. The costs of these resources are not yet reflected in electricity rates.

It is important to note that California renewable energy requirements extend beyond SB 2 (1X). California currently has 13 programs that are designed to encourage the development of renewable energy. Figure 4-4 illustrates the breadth and complex nature of California renewable electricity procurement programs.

Figure 4-4: Relationship of Renewable Energy Programs (RPS Programs Defined by Black Box Outline)



Source: California Public Utilities Commission Division of Ratepayer Advocates. The Renewable Jungle – A Guide to California's Renewable Policies and Programs. 2012.

This complexity can increase overall costs associated with meeting renewable energy goals, both those policies and regulations by the RPS and those separate from the RPS. As PG&E notes:

> *"…the impact of mandated procurement programs focused on particular technologies or project size will be more significant as they become a larger share of PG&E's incremental*

> *procurement goals. Programs focused on mandated procurement of certain technologies or on projects within a specific size range do not optimize RPS costs for customers and may not serve as an efficient procurement mechanism. PG&E expects that these programs may therefore increase the overall costs of PG&E's RPS portfolio for customers."*[11]

Renewable resources are predominantly intermittent; the reliability of energy generation varying from source to source. Solar and wind resource intermittency can vary significant from year to year, season to season, and in some cases hour to hour. Therefore, in order to maintain reliability on the grid, the energy output of intermittent renewable production is supplemented by other dispatchable resources, which can be ramped up or down as intermittent resources increase or decrease production. The need to have available power facilities introduces additional costs on the system. Even if these costs are not represented in contracted prices, they are still recovered at the expense of ratepayers. However, there is not yet a method to calculate those integration costs or determine the precise extent of the ongoing need. As PG&E notes in its 2013 RPS Procurement Plan:

> *"PG&E's RPS focus is increasingly moving from high volume procurement in a supply constrained environment to a more balanced but evolving market and regulatory environment in which the primary challenges are not signing additional contracts but rather managing:*
>
> *(a) operational challenges such as variability, uncertainty, ramping up and down, etc. that PG&E's bundled portfolio may experience from this unprecedented growth of generally non flexible and non dispatchable generation; and*
>
> *(b) increased customer costs over time from the rapid growth in renewable deliveries beginning now and continuing through the remainder of this decade."*[12]

These "indirect costs" associated with renewable energy also include the transmission costs necessary to build enough capacity to transmit the required renewable energy from where it is generated to where it is consumed. With the exception of distributed solar photovoltaics ("PV") (albeit in limited amounts) the geographical location of renewable resources is often far from load centers. While clearly this situation necessitates new transmission capacity, so does normal load growth. It is therefore difficult to precisely determine what portion of the state's future transmission build-out is specifically attributable to the RPS.

The next discussion sharpens the focus on the major drivers of these added costs to the ratepayer, namely renewable resource costs, transmission, and integration costs. Given the rapid growth of distributed generation ("DG"), specifically solar PV, this paper also addresses a major regulatory issue now being debated: cost shifts associated with fixed infrastructure costs being borne disproportionately by "non-PV" customers as a result of the manner in which DG regulations are currently structured.

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[11] Pacific Gas and Electric Company's (U 39 E) 2013 Renewable Energy Procurement Plan – June 28 Draft (Public Version). Rulemaking 11-05-005, June 28, 2013.

[12] Pacific Gas and Electric Company's (U 39 E) 2013 Renewable Energy Procurement Plan – June 28 Draft (Public Version). Rulemaking 11-05-005, June 28, 2013.

4.1.1 Drivers of Costs

Renewable Energy Procurement Costs

Although costs for some renewable technologies are declining, particularly solar PV, the costs of renewable technologies are still higher on average than conventional resources. Even when considering the fuel cost advantages of renewable resources, they are still higher on a levelized basis (Table 4-1).[13]

Table 4-1. Estimated Levelized Cost of New Generation Resources, 2018

Plant type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
Dispatchable Technologies						
Conventional Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced Coal	85	84.4	6.8	30.7	1.2	123
Advanced Coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural Gas-fired						
Conventional Combined Cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced Combined Cycle	87	17.4	2	45	1.2	65.6
Advanced CC with CCS	87	34	4.1	54.1	1.2	93.4
Conventional Combustion Turbine	30	44.2	2.7	80	3.4	130.3
Advanced Combustion Turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced Nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12	0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111
Non-Dispatchable Technologies						
Wind	34	70.3	13.1	0	3.2	86.6
Wind-Offshore	37	193.4	22.4	0	5.7	221.5
Solar PV[1]	25	130.4	9.9	0	4	144.3
Solar Thermal	20	214.2	41.4	0	5.9	261.5
Hydro[2]	52	78.1	4.1	6.1	2	90.3

Source: U.S. Department of Energy – Energy Information Administration. *Annual Energy Outlook 2013. Levelized Cost of New Generation Resources in The Annual Energy Outlook 2013.* January 2013.
[1]*Costs are expressed in terms of net AC power available to the grid for the installed capacity.*
[2]*As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.*
Note: These results do not include targeted tax credits such as the production or investment tax credit available for some technologies, which could significantly affect the levelized cost estimate. For example, new solar thermal and PV plants are eligible to receive a 30 percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $22 per MWh ($11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30 percent investment tax credit, if placed in service before the end of 2013, or (2012, for wind only).

Renewable resources are not only more expensive than natural gas fired generation, there is also the issue that the additional volume of these resources as a percentage of the total generation fleet will lead to additional and increased RPS-related costs going forward. Currently, the three IOUs, LADWP and SMUD have between 17 percent and 20 percent of their portfolio comprised of RPS-eligible renewable resources (See Table 4-2). Renewable generation is projected to increase by between 70 percent and 99 percent by

[13] Levelized costs are an economic assessment of the cost of the energy-generating system including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and the cost of capital.

2020 in order to meet the 33 percent RPS requirement. In the case of the IOUs, much of the difference between their current renewable resource levels and the levels they need for the 33 percent target is already under contract, with many projects under development. However, this underscores the fact that much of the costs associated with RPS compliance have not yet begun to be reflected in rates. Higher cost resources going forward are therefore being added to their portfolios at a higher *rate* than before. This situation would be exacerbated if California were to increase its RPS targets under a new law (and assuming large hydroelectric remains excluded as a qualifying resource). As PG&E notes in its 2013 RPS Procurement Plan:

> *"The impact of signed contacts that PG&E expects to commence operation in the next few years has not yet been captured on customer bills. PG&E forecasts that its energy procurement costs will increase in 2014.The cost of generation from renewable sources is a contributing factor to PG&E's procurement cost increase, which is expected to increase the system average bundled rate by 7.9 percent in 2014."*[14,15]

Table 4-2: Potential RPS Procurement Needs for the State's Largest Utilities (GWh)

	2012				
	SCE	**SDG&E**	**PG&E**	**SMUD**	**LADWP**
Total Retail Sales	75,596,658	16,626,721	76,205,120	10,374	23,232
RPS Target @ 20%	15,119,332	3,325,344	15,241,024	2,075	4,646
Procured RPS	15,043,400	3,377,325	14,510,668	2,132	4,054
Procured RPS (%)	**19.9%**	**20.3%**	**19.0%**	**20.6%**	**17.5%**

	2020				
	SCE	**SDG&E**	**PG&E**	**SMUD**	**LADWP**
Total Retail Sales	77,673,406	20,042,000	80,164,711	11,300	24,126
RPS Target @ 33%	25,632,224	6,613,860	26,454,355	3,729	7,962
Delta from 2012	*10,588,824*	*3,236,535*	*11,943,687*	*1,597*	*3,908*

Source: San Diego Gas & Electric *2012 Preliminary Annual 33% RPS Compliance Report Reporting progress towards meeting the procurement quantity requirements for California's RPS Program*. Rulemaking 11-05-005, August 1, 2013.
Pacific Gas and Electric Company. *2012 Preliminary Annual 33% RPS Compliance Report of Pacific Gas and Electric Company (U 39 E)(Public Version)*. Rulemaking 11-05-005, August 1, 2013.
Southern California Edison Company. *(U 338-E) 2012 Preliminary Annual 33% RPS Compliance Report (Public Version)*. Rulemaking 11-05-005, August 1, 2013.
California Energy Commission, Utility Energy Supply Plans from 2013 - *SMUD PUBLIC S-2 supply form 04-10-2013*, http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2013/
California Energy Commission, Renewables Portfolio Standard Reports and Notices from Publicly Owned Utilities, Fuel and Purchased Power Budget FY 2012-13, http://www.energy.ca.gov/portfolio/rps_pou_reports.html

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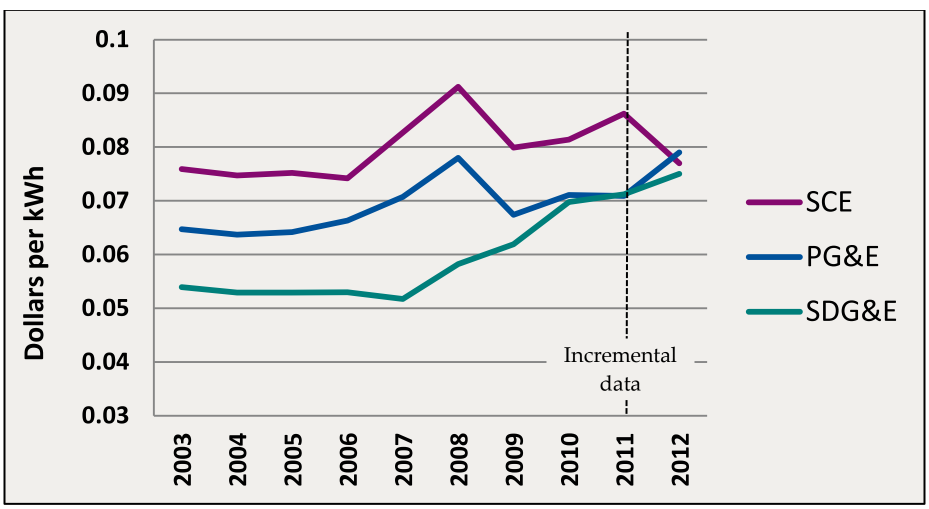
[14] Pacific Gas and Electric Company's (U 39 E) 2013 Renewable Energy Procurement Plan – June 28 Draft (Public Version). Rulemaking 11-05-005, June 28, 2013.
[15] PG&E states the forecast rate increase does not reflect the revenues associated with the sale cap and trade program allowances.

According to a recent report from the CPUC to the Legislature, from 2003 to 2012, the average Time of Day ("TOD") adjusted price of approved RPS contracts by the CPUC has increased from 5.4 cents to 9.9 cents/kilowatt-hour ("kWh") in nominal dollars, or 8.1 cents to 9.9 cents/kWh in real dollars.[16] The CPUC states this is a result of a transition in resources away from existing, relatively lower cost renewable facilities contracted at the beginning of the RPS program (mostly "Qualifying Facilities" under the Public Utilities Regulatory Policy Act of 1978 "PURPA") towards mostly new facilities that typically result in higher contract costs in order to recover the capital needed to develop them. Figure 4-5 shows the procurement expenditures of the three IOUs in terms of the weighted average costs per kWh adjusted for contract specific TOD factors.

The CPUC states that contract costs have also increased in part due to changes in the technology mix, increases in commodity costs, and demand exceeding supply. It is important to note that many of these new contracts benefit from the federal production tax credit ("PTC"), investment tax credit ("ITC") and the attendant Section 1603 cash grant program. The Section 1603 program has expired and the PTC and ITC are set to expire under current law in 2013 and 2016, respectively. If these tax credits are not renewed, then contracts signed after their expiration will likely be priced higher, all else being equal, by the amount of the tax subsidy in additional to any technology cost changes due to market forces.

Figure 4-5: Weighted Average TOD-Adjusted RPS Procurement Expenditures of Bundled Renewable Energy by Year (2003 – 2012)



Source: California Public Utilities Commission. *The Padilla Report to the Legislature – The Costs of Renewables in Compliance with Senate Bill 836* (Padilla, 2011). 2013.

The CPUC notes that the average cost of renewable energy, including older Qualifying Facilities, remains above the average cost for the total energy portfolio (See Figure 4-6).

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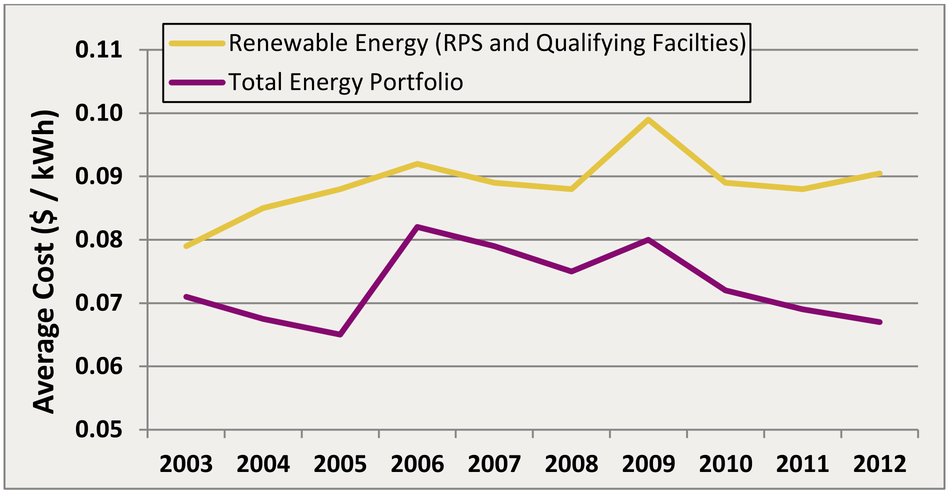
[16] California Public Utilities Commission. *The Padilla Report to the Legislature – The Costs of Renewables in Compliance with Senate Bill 836* (Padilla, 2011). 2013.

Although it acknowledges that total energy portfolio costs are decreasing due to natural gas price declines and one-time refunds in rates in 2011 and 2012.[17]

Figure 4-6: Average Cost of IOU RPS Sources and Total Energy Portfolio



Source: California Public Utilities Commission. Electric and Gas Utility Cost Report. Public Utilities Code Section 747 Report to the Governor and Legislature. 2012.

Transmission and Integration Costs

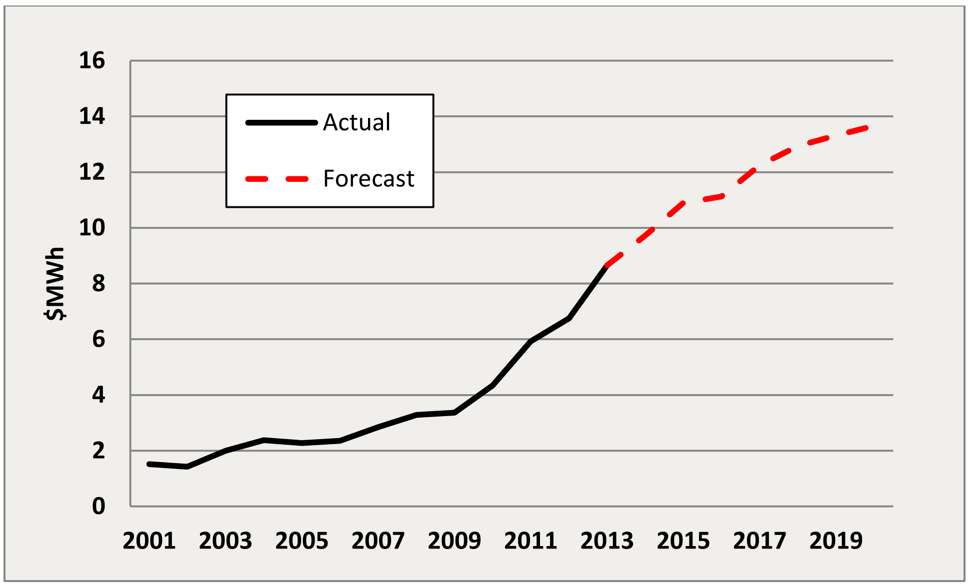
There can be considerable indirect costs of integrating renewables into the electric grid. These indirect costs are typically not accounted for in prices for contracted purchases of renewable energy. Typically, specific renewable contracts do not include the costs associated with fossil fuel-based backup and load following generation, transmission and distribution grid upgrades, and other measures needed to maintain grid reliability. Therefore, understanding the entire cost impact of the RPS program also requires understanding the magnitude of these indirect costs.

In terms of transmission costs, while the California Independent System Operator ("CAISO") does not generally conduct retail rate impact analyses, it is empowered to make decisions on needed transmission infrastructure to meet its goals. The primary avenue through which it accomplishes this is the Annual Transmission Plan. The most recently completed plan—the 2012-2013 Transmission Plan—was completed in March 2013. It called for approximately $421 million of transmission additions that are considered renewable upgrades. It should be noted that the "renewable" designation does not necessarily indicate that a transmission line is needed to meet renewable standards. It may have instead been identified as a reliability need, but because it also provides sufficient benefits to renewable delivery it is classified as a policy-driven element. Conversely, some projects designated as reliability projects may still provide renewable benefits. The CAISO does not formally itemize its transmission costs in such a way as to give a specific dollar amount to renewable delivery or renewable integration.

[17] California Public Utilities Commission. Electric and Gas Utility Cost Report. Public Utilities Code Section 747 Report to the Governor and Legislature. 2012

It is nevertheless clear that transmission costs have been rising in California and that this is not only due to load growth. An indication of these increases can be seen in the increase in the Transmission Access Charge ("TAC"), a wholesale transmission charge for users of the CAISO grid. The charge has been expanding recently due in large part to the addition of new high voltage transmission specifically dedicated to bringing renewable transmission onto the grid. In 2008, the High Voltage TAC was \$3.53/megawatt-hour ("MWh") in 2008 while currently it is at \$8.99/MWh.[18] According to the CAISO 2012-13 Transmission Plan there is not much need for additional large scale transmission to accommodate *a 33 percent RPS* apart from those projects currently underway and no other major projects are currently planned. Figure 4-7 shows the forecasted TAC to 2020.

Figure 4-7: High Voltage Transmission Access Charge Forecast



Sources: California Independent System Operator. *High Voltage Rates archive.* http://www.caiso.com/Documents/High%20voltage%20rates%20archive.
Navigant Internal TAC Forecast

In terms of integration costs, both the CPUC and the CAISO have identified the likelihood that additional, flexible capacity will be required to provide the required firming capacity needed to balance intermittent renewables.[19] However, the costs associated with this additional capacity are unclear. The CAISO has conducted several Renewable Integration Studies at the behest of the CPUC and for their own purposes. Those studies preliminarily found that in some sensitivity cases there may be a need for

[18] Vast majority of this increase is due to new major transmission facilities to access renewable rich regions of California, e.g. Tehachapi wind, Mojave solar and the Imperial Valley.
[19] See "Proposed Decision Adopting Local Procurement Obligations for 2014, A Flexible Capacity Framework, and Further Refining the Resource Adequacy Program," issued May 28, 2013 (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K705/65705989.pdf); "CAISO Initial Comments on Workshop Issues," R.11-10-023,filed April 8, 2013 (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M064/K140/64140277.pdf); and CAISO Reply Comments on Workshop Issues," R.11-10-023, filed April 15, 2013 (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M064/K660/64660258.pdf).

up to 4,000 MW of new capacity. However, in most cases there is adequate capacity to meet the reserve needs. At issue, though, is making sure that capacity is indeed available. To this end the CAISO has instituted Flexible Resource Adequacy stakeholder processes to try and ensure that resources with the needed operational/ramping characteristics are in place to accommodate the variability of intermittent resources such as wind and solar. SCE underscores the issue of indirect costs in its 2013 RPS Procurement Plan stating that:

> *"Integration costs are real costs associated with intermittent renewable resources and the Commission should not rely on outdated assumptions and the lack of public analysis as the basis for a zero integration cost adder."*[20]

Costs Associated with Distributed Solar

There is a considerable amount of renewable generation being installed in addition to that being counted towards the RPS. These installations are mostly in the form of distributed solar on residential and commercial installations, particularly rooftop applications. Distributed solar is gaining significant traction primarily as a result of improving economics driven by market forces (e.g. decreases in solar module prices), by federal policies (i.e. the ITC) and state-level regulations—in particular rules regarding net energy metering ("NEM").

NEM rules stipulate that owners of PV systems on the customer-side of the meter are compensated for energy that is 'exported' to the grid. The compensation rate is the full retail rate, inclusive of transmission, distribution, and other non-energy charges. This means that when energy from a PV system is being exported to the grid, the utility is not recovering costs associated with its infrastructure. These costs then have to be "spread" over a smaller customer base (i.e. non-solar customers) – leading to higher electric bills and potentially more customers choosing solar because the economics are better. Customers that are not participating in NEM programs are therefore effectively paying a disproportionate share of the costs associated with the transmission and distribution system.

The NEM cost shift issue is increasingly becoming a major issue for the state's utilities. This is fundamentally an issue of rate design and cost recovery for both energy and infrastructure because current retail rate designs do not adequately address this issue. The importance of this issue will increase in direct proportion to the amount of distributed solar installed on the grid. As SDG&E noted in a recent report on utility costs to the Legislature:

> *"Absent adoption of an unbundled distribution integration and reliability service, elimination of existing tier differentials, or elimination of the NEM program, customers that lack competitive alternatives will be forced to subsidize those with competitive options, potentially at significant cost. This could generate tremendous opposition to California's renewable energy efforts, potentially stifling progress on an important long-*

[20] *Southern California Edison Company's (U 338-E) 2013 Renewables Portfolio Standard Procurement Plan- Volume 1 (Public Version)*. Rulemaking 11-05-005, June 28, 2013.

term policy initiative. California's renewable energy programs should be designed to last."[21]

4.2 Cap and Trade

California's GHG cap and trade program took effect on January 1, 2012 (with amendments effective September 1, 2012). The enforceable compliance obligation began on January 1, 2013. The cap and trade program sets a firm declining cap covering 85 percent of the state's GHG emissions and covers about 350 businesses, representing roughly 600 facilities. It includes major GHG-emitting sources, such as electricity generation (including imports), and large stationary sources that emit more than 25,000 metric tons of carbon dioxide equivalent ($MTCO_2e$) per year.[22] California's cap and trade program is the second active cap and trade program in the U.S. after the Regional Greenhouse Gas Initiative in the Northeast.

In 2015, the program will be expanded to require fuel providers to address emissions from transportation fuels, and from combustion from other fossil fuels not directly covered at large sources in the initial phase of the program. Entities subject to the cap and trade regulation are referred to as "covered entities."

In an approach designed to give businesses and industries sufficient time to reduce their emissions in a cost-effective manner, without unnecessary short-term costs, CARB allocated the bulk of allowances for free in 2013, but will gradually auction an increasing number of allowances between 2013 and 2020. The IOUs are required to sell their allocated allowances at CARB quarterly auctions. The proceeds from these auctions must then be used to mitigate the bill impacts on their distribution customers (explained below). Most POUs own and operate their own generation in additional to purchasing power. Therefore, allowances directly allocated to POUs may either be consigned for sale at the general quarterly auctions or used directly to meet their compliance obligations.

California's carbon cap and trade program will impact the price of electricity by reflecting the cost of carbon in fuels used to produce electricity. The cap and trade program limits GHG emissions associated with the production of electricity in California or electricity that is scheduled to be delivered into the state. Since the California electricity market is mostly restructured into wholesale and retail (distribution) elements, this means that prices for wholesale power will be higher as a function of new carbon costs. Similarly, for GHG-emitting generation sources that are owned by utilities (mostly POUs) costs associated with procuring sufficient allowances to cover emission will be reflected in the rates charged to electricity consumers.[23]

4.2.1 Drivers of Costs

At a basic level, the total impact of carbon on electricity prices depends primarily on two factors: the market price of carbon allowances and aggregate emission from covered

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[21] California Public Utilities Commission. Electric and Gas Utility Cost Report. *Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases. June* 2013.

[22] The terms "carbon" and "greenhouse gas" are used interchangeable throughout this section although the authors acknowledge they are technically different; albeit insignificantly for purposes of this paper.

[23] This section does not address costs associated with GHG-intensive production practices (e.g. cement production) and how this is in turn will be reflected in production costs and prices of products.

entities, including the relative shares of coal, natural gas, and oil in total electricity production.[24]

In the California market, carbon pricing affects wholesale market prices to the extent that market participants covered by the program increase bids into the CAISO market to account for the incremental cost of allowances. The CAISO amended its tariff, effective January 1, 2013, to include GHG compliance cost in the calculation of each of the following:

- Resource commitment costs (start-up and minimum load costs);
- Default energy bids, which are bids used in the automated local market power mitigation process; and
- Generated bids (i.e. bids generated on behalf of resource adequacy resources and as otherwise specified in the CAISO tariff).

Cost of Carbon Allowances

The CAISO recently issued its first analysis on the initial effects of California's cap and trade program.[25] The report states that the initial market price for GHG allowances has ranged from $13.50 to $16.50 per ton over the first three months of 2013, averaging about $14.55 per ton.[26] According to the CAISO, roughly 85 percent of gas-fired capacity included higher bids in January 2013 than in the last week of 2012 (i.e. prior to the cap and trade program taking effect), with approximately 80 percent of this capacity increasing their bids by less than $10/MWh. The CAISO states that an increase of this magnitude is within the range of additional carbon costs associated with generating units with different efficiencies given allowance costs during this time period. By way of example, for a relatively efficient unit with a heat rate of 8,000 MMBtu/kWh, a $14.55 allowance price represents an additional cost of about $6.19/MWh.[27] However, other analyses have indicated this impact could be as high as $10/MWh depending on the efficiency of the power plant.[28]

However, projections for carbon prices are highly uncertain, being a function of not only the generation mix in the electricity sector but also of the supply and demand dynamics of a emission trading system encompassing 85 percent of California's GHG emissions.

A recent draft study on the variability of carbon prices to supply and demand patterns highlights this uncertainty. Bailey *et al* state that:

> *"Our empirical assessment of the potential demand for emissions allowances and supply of abatement and offsets suggests that the most likely outcome in the market will be a price very close to the auction reserve level. In what we view as the most plausible scenario, we find an 80 percent probability of such an outcome. In all of the scenarios we examine, however, we find a very low probability that the price will be in an intermediate*

[24] Among these fuels, oil plays a negligible role in electricity generation in California. Between coal and natural gas, natural gas is much more prominent in California and has roughly half the carbon content of coal.

[25] CAISO, Department of Market Monitoring. *Q1 2013 Report on Market Issues and Performance.* May 29, 2013.

[26] CAISO, Department of Market Monitoring. *Q1 2013 Report on Market Issues and Performance.* May 29, 2013.

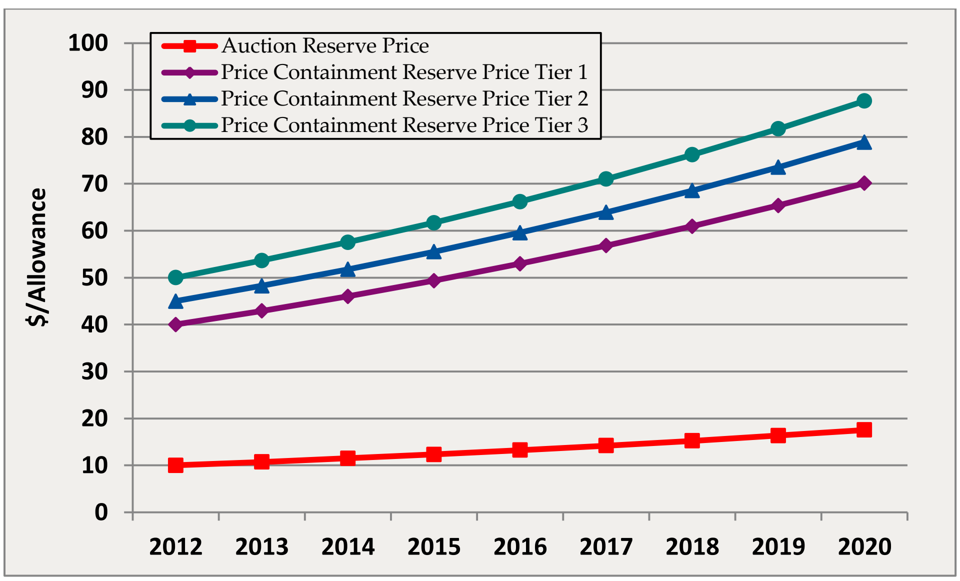
[27] $14.55/mtCO2e x 0.053165 mtCO2/MMBtu x 8,000 Btu/kWh = $6.19/MWh.

[28] Shively, Bob. "What are the impacts of carbon pricing in California?" posted on July 18, 2013 by Enerdynamics.

range, substantially above the auction reserve level, but below the containment reserve prices. Thus, most of the remaining probability weight is on outcomes in which some or all of the allowances in the price containment reserve are needed."[29]

Figure 4-8 shows the level of the auction reserve price compared to the three tiers of the price containment reserve price. While the Bailey study points to the likelihood that carbon prices will be at or near the auction reserve price, it also points to the possibility that prices could be substantially higher, approaching the levels seen at the higher end of the band (i.e. the price containment reserve price). It should be noted however that the price containment reserve price is not technically a price ceiling. Containment reserve prices are those at which additional GHG allowances are sold to the market in an effort to increase the available market supply of allowances and therefore put downward pressure on carbon prices as a function of supply and demand economics. However, if demand for allowances were to exceed supply despite the release of these additional allowances, carbon prices could indeed be higher than the price containment reserve price.

Figure 4-8: California GHG Allowance Auction Reserve And Price Containment Reserve Prices



Source: California Code of Regulations Title 17, Subchapter 10, Article 5. Sections 95800 to 96023. California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. 2011.

Basic economics advise that the price of any tradable good is a function of supply and demand. In a cap and trade system, the supply of the good in question (e.g. GHG allowances) is fixed; total supply is equal to all allowances allocated under the cap (inclusive of those banked for future compliance requirements as well as those allocated to the price containment reserve). Demand is a function of actual, realized emissions. The higher the emissions from California covered entities, the higher the demand curve will

[29] Elizabeth M. Bailey, Severin Borenstein, James Bushnell, Frank A. Wolak and Matthew Zaragoza-Watkins. DRAFT - Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market. March 12, 2013.

be relative to the supply curve. Put another way, demand for allowances can be variable depending on economic output and the amount of electricity generation from fossil-based resources, among other drivers.

Hence the logic underpinning the price containment reserve function of the auction process. If market allowances prices begin to increase to the price containment reserve trigger levels (i.e. Tiers 1-3), additional allowances will be sold to the market in an effort to increase supply and stabilize prices. If the additional allowances sold by CARB from the price containment reserve are not sufficient to cover the incremental demand causing the increase in market prices, then it is possible that carbon prices could increase past the price containment reserve price. It is therefore worthwhile to consider what could cause additional demand for carbon allowances beyond which was already factored into the original allowance allocation process.

Electricity Generation Mix

There are several market events and system requirements that have surfaced in the last 1-2 years (i.e. after the initial cap and trade requirements and allocations were set) that can put upward pressure on GHG emissions in the electricity sector therefore increasing demand for GHG allowances in California. The most important of which is the shutdown of the San Onofre Nuclear Generating Station ("SONGS"). If the lost generation is replaced with natural gas fired units,[30] this would represent an additional 2,200 MW of fossil-based generation, equating to roughly 15 TWh[31] of energy that would be required to hold GHG allowances. It is unclear (but unlikely) whether this additional fossil-based capacity was factored into CARB's original assessment and design of the cap and trade system.

Potential Impact on Ratepayers

Regardless of the uncertainty in carbon prices, there are studies that have estimated the impacts on electricity rates from a given carbon allowance price point. Table 4-3 shows the CPUC's estimated ranges of bill increases for representative customer classes in the IOU's service territories, assuming an allowance cost of $10 per ton (the 2013 auction reserve price) and an allowance cost of $40 per ton (the 2013 first tier Price Containment Reserve price).[32]

[30] It is unlikely this capacity will be replaced with coal fired units given the state's effective moratorium on new coal–fired generating capacity due the Emission Performance Standard (SB 1368), which establishes an emissions standard for baseload generation of 1,100 lbs CO_2 /MWh; or similar to a natural gas fired unit.
[31] Assuming a capacity factor of 80%.
[32] It should be noted that these prices are statutorily inflated annual by 5% plus CPI as shown in Figure 4-8.

Table 4-3: CPUC Estimated Bill Increases for Various Customer Classes

	$10 per ton Allowance Price	$40 per ton Allowance Price
Residential = 500 kWh/Month	0.7%- 1.0% Increase	2.6%- 3.8% increase
Residential = 1000 kWh/Month	1.5% - 2.5% Increase	5.9% - 9.8% increase
Residential = 1500 kWh/Month	1.6% - 2.7% Increase	6.3% - 10.8% increase
Commercial = 750 kWh/Month	1.0%- 1.4% Increase	4.0% - 5.5% increase
Commercial = 1500 kWh/Month	1.1% – 1.3% Increase	4.3% - 5.7% increase
Commercial = 3000 kWh/Month	1.1%-1.5% Increase	4.5% - 5.8% increase

Source: California Public Utilities Commission. Decision Adopting Cap-And-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities. Rulemaking 11-03-012. Decision 12-12-033. 2012.

In the same document, The CPUC also estimated the impact of carbon costs on system average rates. These estimates are based on a model that compares rates with and without carbon costs keeping other variables constant, under different policy scenarios.[33] Using the "accelerated" policy scenario defined in that model[34], Table 4-4 below shows projected increases in system average rates between 2 percent and 8 percent between 2013 and 2020, depending on the assumed price of allowances. It should be noted that this is based on an assumption that system average rates without carbon prices increase by 2.4 percent compounded annually between 2013 and 2020.

Table 4-4: CPUC Estimates of Carbon Price Impacts on Aggregate System Average Rates (2008$)[35]

	No Carbon Price ($/kWh)	Allowance price assumed to be Auction Reserve Price[36]		Allowance price assumed to be First Tier of Price Containment Reserve[37]	
		($/kWh)	% Change	($/kWh)	% Change
2013	0.157	0.161	2.00%	0.171	8.36%
2014	0.161	0.165	2.02%	0.175	8.40%
2015	0.166	0.169	2.04%	0.180	8.46%
2016	0.170	0.173	2.05%	0.184	8.50%
2017	0.174	0.177	2.07%	0.188	8.54%
2018	0.178	0.181	2.08%	0.193	8.56%
2019	0.181	0.185	2.09%	0.197	8.58%
2020	0.185	0.189	2.10%	0.201	8.61%

Source: California Public Utilities Commission. Decision Adopting Cap-And-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities. Rulemaking 11-03-012. Decision 12-12-033. 2012.

Despite the impact of carbon prices on wholesale power costs, there are important statutory obligations on the part of market participants that will impact how these costs

[33] This model is referred to as the "E3 Model" that was developed in R.06-04-009, in which the CPUC evaluated options for allocating carbon allowances among California utilities.
[34] The "accelerated policy scenario" assumes 33% RPS by 2020, 'high case' energy efficiency by 2020, and increased GHG savings from combined heat and power (CHP) relative to the 'reference scenario.' http://ethree.com/documents/GHG%20update/CPUC_GHG_Revised_Report_v3b_update_Oct2010.pdf
[35] It should be noted that the system average rate projections provided by the CPUC in the document different from CEC estimates. It is not known how these system average rate projections were developed, or if in fact they are provided for illustrative purposes only.
[36] Pursuant to ARB.17 CCR § 95911(a)(b)(5).
[37] Pursuant to ARB.17 CCR § 95913(d)(2).

are reflected in overall electricity bills (as opposed to electricity rates). As part of the cap-and-trade program, a portion of the allowances that were allocated to the state's electric distribution utilities are to be consigned to auction with the sale proceeds used to compensate electricity consumers for the costs associated with higher electricity rates.

Pursuant to CPUC decision D.12-12-033[38], the IOUs will distribute these proceeds to the following ratepayers based on a prescribed formula:

- Emissions-intensive and trade-exposed businesses;
- Small businesses[39]; and
- Residential ratepayers.

Remaining revenues will be given to residential customers as an equal semi-annual bill credit. It is likely that these ratepayers will be made whole in terms of the higher electricity rates they see on their bills. However it is important to note that there are some classes of ratepayers that will not receive auction proceeds. Those classes of customers not receiving auction proceeds will incur additional carbon costs reflected in electricity rates but will not receive any corresponding offset benefits from the proceeds of the auction.

In terms of commercial and industrial consumers of electricity, the CPUC determined that entities identified by CARB as eligible for industry assistance (referred to as emissions-intensive and trade-exposed, or EITE, entities) should be allowed to receive auction proceeds in an effort to reduce the impact that carbon costs have on their electricity bills.

The formulas used to allocate revenue to these industries are in the process of being developed. Additional studies will be conducted to determine if other industrial sectors, aside from those identified by CARB, should be compensated with GHG allowances revenue. Table 4-5 lists those sectors that are currently listed as EITE sectors by CARB. Those commercial entities that are not deemed eligible for receipt of allowance auction proceeds will see increases in their electricity bills as a result of GHG allowance costs. SCE noted this issue in a recent report to the Legislature when it stated that:

> *"…the Commission issued a decision in R.11-03-012 that primarily will return the cap & trade revenue to residential customers and excludes many businesses including universities, and hospitals."*[40]

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[38] California Public Utilities Commission. *Decision Adopting Cap-And-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities. Order Instituting Rulemaking to Address Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions.* Rulemaking 11-03-012.Decision 12-12-033. 2012.
[39] Defined as non-residential businesses with energy demand that does not exceed 20kW for more than 3 months during the previous 12 month period.
[40] California Public Utilities Commission. Electric and Gas Utility Cost Report. *Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases. June* 2013.

Table 4-5: Sectors That Will Likely Receive GHG Auction Revenue

Sector	NAICS Code	Sector	NAICS Code
Crude Petroleum and Natural Gas Extraction	211111	Cut and Sew Apparel Manufacturing	3152
Natural Gas Liquid Extraction	211112	Breweries	312120
Potash, Soda, and Borate Mineral Mining	212391	Petroleum Refineries	324110
All Other Nonmetallic Mineral Mining	212399	Industrial Gas Manufacturing	325120
Paper (except Newsprint) Mills	322121	Biological Product (Except	325414
Paperboard Mills	322130	Diagnostic) Manufacturing	
All Other Petroleum and Coal Products Manufacturing	324199	Gypsum Product Manufacturing	327420
All Other Basic Inorganic Chemical Manufacturing	325188	Mineral Wool Manufacturing	327993
All Other Basic Organic Chemical Manufacturing	325199	Rolled Steel Shape Manufacturing	331221
Nitrogenous Fertilizer Manufacturing	325311	Secondary Smelting and Alloying of Aluminum	331314
Flat Glass Manufacturing	327211	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (Except Copper and Aluminum)	331492
Glass Container Manufacturing	327213	Iron Foundries	331511
Cement Manufacturing	327310	Turbine and Turbine Generator Set Units Manufacturing	333611
Lime Manufacturing	327410	Pharmaceutical and Medicine Manufacturing	325412
Iron and Steel Mills	331111	Aircraft Manufacturing	336411
Rolled Steel Shape Manufacturing	331221	Support Activities for Air Transportation	4881
Food Manufacturing	311		

Source: California Air Resources Board, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, California Code of Regulations. Article 5: CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS. Table 8-1. October 2011.

4.3 Low Carbon Fuel Standard

In 2007 Governor Schwarzenegger signed Executive Order S-01-07 establishing California's Low Carbon Fuel Standard ("LCFS").[41] The LCFS was developed consistent with guidance provided in AB 32 relating to GHG emission reductions associated with statewide fuel supplies. CARB adopted the LCFS regulations in 2009. Although the program has been implemented and enforced since the beginning of 2011, there are considerable uncertainties with respect to legal challenges of the law. The LCFS is a flexible market-based standard implemented using a system of credits and deficits. Section 95482 of the LCFS requires regulated parties, beginning in 2011, and each year thereafter, to meet annual average carbon intensity requirements that achieve the 2020 Target. Regulated Parties generate either transportation fuels credits or deficits based on the carbon intensity of the transportation fuels for which they are regulated. Transportation fuels that have lower carbon intensities than the compliance schedule include ethanol, biodiesel (both only from some feedstock/production pathways), ETE, natural gas, electricity, and hydrogen. CARB quantifies and publishes carbon intensity values for all fuel pathways.

Seven classes of Regulated Parties are initially established by type of transportation fuel including: (1) gasoline; (2) diesel fuel and diesel fuel blends; (3) liquid alternative fuels not blended with gasoline; (4) blends of liquid alternative fuels and gasoline or diesel

[41] California Code of Regulations Title 17, Subchapter 10. Climate Change, Article 4. Regulations to Achieve Greenhouse Gas Emission Reductions, Subarticle 7. Low Carbon Fuel Standard §§ 95480-95490.

fuel; (5) natural gas; (6) electricity; and (7) hydrogen or hydrogen blends. Extensive criteria and rules are developed for designating "Producers and Importers," as Regulated Parties and the effects of various transactions within the fuel cycle among the various supply chain participants regarding the resulting Regulated Party.

4.3.1 Drivers of Costs

According to CARB, the LCFS will have little effect on the price of gasoline. Their internal estimates conclude that gas prices may increase by nine to thirteen cents per gallon.[42] They estimate that diesel fuel prices could decrease by four cents per gallon at the outset, and increase by 26 cents per gallon by 2020.[43] The reasons CARB offers these relatively low estimates are based on the assumption that increased investment in low-carbon fuels will reduce their price due to innovative technology and cost efficiencies associated with the rapid adoption of the LCFS goals between now and the year 2020.

However, there is considerable uncertainty regarding the cost impacts of California's LCFS. CARB and a recent University of California Davis ("UCD") study project relatively low cost increases and achievable compliance. On the other hand, studies by Sierra Research Inc. ("Sierra") and Stonebridge Associates Inc. ("Stonebridge") call into question the assumptions, analyses, and conclusions asserted by CARB. Their combined effect is to emphasize the divergence of opinions, and therefore the increasing level of uncertainty associated with LCFS compliance and costs.

CARB analyzed the feasibility and cost of compliance with the LCFS using 11 "illustrative" LCFS compliance scenarios related to gasoline and gasoline substitutes.[44] CARB's analysis relied heavily on assumptions regarding substitute fuels availability, technological improvements that would reduce their CI, and a relatively rapid, accelerated public adoption rate for alternative vehicle technologies. CARB recognized that the economic analyses of the LCFS are:

> *"…greatly affected by future oil prices and the actual production costs and timing of lower CI alternative fuels. Economic factors, such as tight supplies of lower-CI fuels or a lengthy economic downturn keeping crude demand down, could result in overall net costs, not savings, of the LCFS…. staff recognizes that RFS2[45] fuels will have to be available in significant quantities for the proposed LCFS to succeed."*[46]

CARB's assumptions, analysis, and conclusions have been questioned in detailed studies conducted by Sierra and Stonebridge. Each of those studies provided detailed analysis

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[42] California Air Resources Board. Proposed Regulation to Implement the Low Carbon Fuel Standard – Volume 1 – Staff Report: Initial Statement of Reasons. March 5, 2009.

[43] Ibid.

[44] California Air Resources Board. *Proposed Regulation to Implement the Low Carbon Fuel Standard – Volume 1 – Staff Report: Initial Statement of Reasons.* March 5, 2009.

[45] The Renewable Fuel Standard (RFS) is a federal program that requires transportation fuel sold in the U.S. to contain a minimum volume of renewable fuels. The Environmental Protection Agency (EPA) administers the RFS program with volume requirements for several categories of renewable fuels. Among other provisions, the RFS sets mandatory blend levels for renewable fuels while also establishing GHG reduction criteria.

[46] California Air Resources Board. *Proposed Regulation to Implement the Low Carbon Fuel Standard – Volume 1 – Staff Report: Initial Statement of Reasons.* March 5, 2009.

and supporting source methodologies to assert that there are substantial levels of uncertainties associated with:

- The ability of industry to significantly reduce the CI values of alternative fuels, and to produce, distribute, and dispense them at an adequate retail scale to support compliance;
- The pace at which California drivers will purchase and use flexible-fuel vehicles, and the ability of industry to manufacture and integrate the needed engine technologies capable of running on alternative fuels; and
- The rate at which compliance credits associated with alternative fuel consumption and sales can be generated to offset the deficits that will be incurred when consuming and selling (i.e. replacing) conventional gasoline and diesel, especially as their credit/deficit magnitudes decline and increase, respectively when compared to declining annual compliance targets.

Potential Infrastructure Costs

CARB has made the following assumptions in its Initial Statement of Reasons for the LCFS with regard to the infrastructure needed for implementation of the LCFS. The Energy Independence and Security Act of 2007 (EISA), which established additional federal renewable fuel standards, known as RFS2, will result in significant changes in California's transportation fuels and require ethanol-related infrastructure to be constructed in the state even without the LCFS. CARB staff then recognized that the federal Renewable Fuel Standard (RFS2) will bring significant quantities of ethanol to California, and that the infrastructure required to meet the mandates of RFS2 is essentially the same infrastructure necessary to meet the potential ethanol requirements of the LCFS; therefore, nearly all of the ethanol-related infrastructure costs can be attributed to RFS2 compliance.

The status of zero-emission vehicle technologies was examined by an independent expert review panel ("Panel") established by CARB in 2006. The Panel's projection was that the intense effort on fuel cell electric vehicles would result in technically capable vehicles by the 2015 to 2020 timeframe, but successful commercialization would be dependent on meeting challenging cost goals and availability of an adequate hydrogen infrastructure. The Panel projected this technology to be in a pre-commercial stage (1000's of vehicles per year) based on global volumes in the 2010 to 2020 timeframe. Staff assumed increased throughput of compressed natural gas ("CNG") would require both expanding existing CNG fueling stations (adding infrastructure for increased capacity) and building new stations. Staff assumed the new CNG stations would be added to existing truck stops along major freeways. To accommodate the lower-CI fuels in the market, CARB assumed that businesses will have to invest in the necessary infrastructure to produce, distribute, and dispense those fuels.

CARB staff recognized that:

- Conventional gasoline or RFG can contain up to 10 percent ethanol (E10) by volume and be used in any gasoline vehicle;

- Ethanol 10 (nominally 10 percent ethanol, 90 percent gasoline) needs no infrastructure as all storage tanks and dispensing equipment can accommodate up to E10; however,
- E85 (nominally 85 percent ethanol and 15 percent gasoline) can only be used in vehicles designed for its use. Today, these are flexible-fueled vehicles (FFVs) which can accommodate from E0 (gasoline with no ethanol) to E85. Current gasoline equipment at service stations cannot accommodate E85.

The LCFS compliance cost estimates for biofuels alone for each of the CARB illustrative scenarios result in total compliance costs for the gasoline scenarios over the period from 2011 to 2020 from about $22 to as much as $42 billion.[47] These cost estimates do not account for changes in new vehicle prices for vehicles capable of using alternative fuels or costs associated with the development of alternative fuel refueling infrastructure, each of which would increase the estimated LCFS compliance costs.

Critics of CARB's analysis assert that there is insufficient retail dispensing infrastructure currently in place in California to support anywhere near the E85 volumes assumed by ARB staff. CEC has reported that the infrastructure required to achieve 1.75 billion gallons of E85 use per year will cost between $1 and $21 billion, and that the infrastructure required reaching the ARB staff's assumed level of approximately 3 billion gallons per year will cost between $3 and $102 billion.[48] It stands to reason that significant lead time would be required to install this infrastructure, and the cost of the investment plus a return on that investment would have to be realized—most likely through increases in the cost of E85, which is expected to be a viable fuel only if its cost is less than that of gasoline on an energy equivalent basis.

Uncertainties associated with the long-term success of the LCFS extend to biofuels availability and infrastructure projections. For example, biodiesel must be stored in segregated tanks and special blend equipment used to control blend proportions. The infrastructure for this process is not widely available in California. A similar infrastructure requirement would apply to cellulosic diesel and renewable diesel. Further, low biodiesel consumption could in part be explained by recognizing that California refiners do not have the necessary infrastructure for the transport, storage and blending of biodiesel and have therefore chosen to comply with RFS2 requirements in locations where the supply of biodiesel is associated with the necessary blending and distribution infrastructure.

Several reviews have provided varying estimates regarding the ability of the fuels industry to respond and adapt to the LCFS. UCD acknowledges that uncertainties associated with the LCFS merit further decision maker attention by stating the following:

> *"… it is useful for decision makers to understand what conditions might contribute to this type of slow response/high cost scenario and what signals would indicate that such a scenario is playing out, e.g. little or no demand or supply response to changing prices, and large quantities of gasoline exports resulting in declining profits....we believe*

[47] California Air Resources Board. *California's Low Carbon Fuel Standard Final Statement of Reasons.* December 2009.

[48] Draft Transportation Energy Forecasts and Analyses for the 2011 Integrated Policy Report. Aug. 2011.

> *decision makers would benefit from being able to see and understand a full set of sensitivities overall and the key input and modeling uncertainties that have gone into producing them*."

An argument has therefore been made in the literature[49] that the levels of regulatory requirements themselves place an overly aggressive set of expectations for production and infrastructure development on an alternative fuels industry that is in a very immature state. The latter argument suggests that, given the commercial issues the alternatives industry must address, it is being developed as quickly as it can attract investment and prove the commercial viability of its production systems.

[49] Stonebridge Associates, Inc. *The Impact of the Low Carbon Fuel Standard and Cap and Trade Programs on California Retail Diesel Prices.* April 2012.

5. Conclusions

There is not a single, credible source of analytics and data that can inform companies and policymakers regarding the cumulative costs of recent energy-related policies and regulations. However, energy costs in California are increasing over the next several years. This is due to several factors, not the least of which are the costs of implementing a series of state-adopted policies and regulations that have been passed by the legislature and various state regulatory agencies in the last five to seven years. It is essential that total costs including the costs to specific energy consumers of the current policies and regulations are determined and understood.

Increases in California energy costs will be absorbed by all Californians, including local communities. Government services such as fire and police will likely be impacted by increasing fuel and electricity costs. Schools, hospitals, water treatment facilities and other local services will also face higher energy costs that must be addressed by decision makers facing budget challenges.

The complexity associated with simultaneously implementing several transformative policies and regulations within an already complex and increasingly costly energy landscape in California can lead to unintended consequences. These would include but not limited to the following:

1. Extraneous costs and system impacts stemming from multiple regulatory programs with the same ostensible objective (i.e. GHG reductions)
2. Additional strain on the electrical grid resulting in reliability concerns;
3. Transformation of the business model (ratepayer cost shifts); and
4. Limited utility flexibility to address future uncertainties

This paper provided preliminary assessment of cost drivers focusing on three energy-related regulations, namely the Renewable Portfolio Standard, GHG Cap and Trade and Low Carbon Fuel Standard programs.

The implications of these costs are only now beginning to surface. California energy consumers require a comprehensive analysis and understanding in order to make informed energy choices.

A preliminary examination of cost impacts provides the following:

- The 33 percent RPS requirement will lead to increased cost above historical norms.
- Carbon prices will be reflected in electricity and fuel costs, although the application of these costs will not be uniform.
- There is considerable uncertainty regarding the eventual cost impacts of the LCFS and the viability of the market to provide an adequate demand for alternative fuels and the required infrastructure.

The costs associated with these policies and regulations will continue to widen the disparity in energy costs between California and neighboring states. This may exacerbate an existing problem of businesses either opting to locate initially in another state, or leaving the state for other, lower energy-cost states.

The lack of a comprehensive, detailed analysis of the cumulative costs of recent energy-related policies and regulations continues to contribute to a significant amount of uncertainty on the California energy market.

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