Electricity Pricing and Electrification for Efficient Greenhouse Gas Reductions

By Lee S. Friedman
Professor of Public Policy
Goldman School of Public Policy

University of California, Berkeley

July 2, 2013

This report has been prepared for Next 10 in collaboration with the California Council on Science and Technology as part of the Council's project California's Energy Future to 2050: Policy Issues

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lfried@berkeley.edu

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Abstract

To reach its 2050 greenhouse gas reduction goal, California electricity must become cleaner and some activities that are now fossil-fueled must run partially or fully on the cleaner electricity—a process termed electrification. This paper recommends pricing policy reforms that will help to make decarbonization and electrification decisions effectively and efficiently. Its emphasis is on better alignment of prices with social costs. But participation of many other jurisdictions besides California is also necessary for mitigating climate change efficiently. Therefore California policymakers should look favorably upon linkage of its cap-and-trade program with jurisdictions like Quebec that adopt comparable goals and rules. Policymakers should also act soon to clarify state efforts to reduce GHG emissions beyond the 2020 mandate of AB 32—otherwise, the uncertainty lowers expected future allowance prices and deters investments and research and development efforts for cleaner generation, factories, buildings, and other infrastructure. Substantial reform is also needed with the retail pricing of electricity. Restrictions held over from the state's 2001 electricity crisis are preventing 10 million California residences from receiving any carbon price signal at all, despite the fact that they would be compensated for this price increase with dividends. California also needs to transition its electricity customers on to time-varying rates that reflect the large social cost differences of providing service at different times of the day. The prevailing time-invariant system is an inefficient impediment to vehicle electrification—while it only costs about $.05 per kWh to provide offpeak electricity when recharging is convenient, many customers face rates that are more than 6 times this cost. The same misalignment of rates with costs is also hindering the development of grid storage important to manage increased use of intermittent renewable generation. It is hindering participation in demand response programs that avoid inefficient, high-emission peak generation, facilitate increased renewable generation, and can be used to provide better and cleaner ancillary services. Time-varying prices commensurate with costs of service would not only fix these issues, but they would encourage the development of enabling technology to further improve all of these GHG-reducing actions. Important fairness concerns about time-varying rates can be addressed by several rate design methods, including HOOP (Household On and Off Peak) pricing that combines time-varying marginal-cost based volumetric rates with a system of non-distorting graduated fees.

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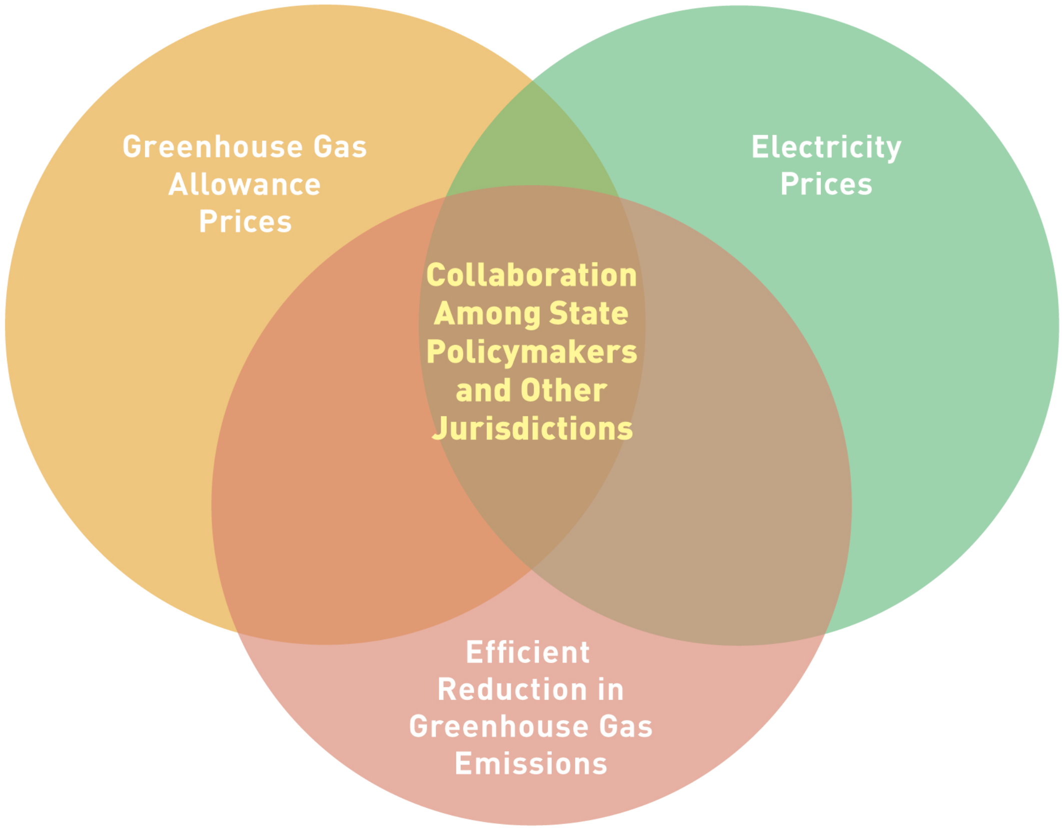
EXECUTIVE SUMMARY

As California proceeds toward its long-run 2050 goal for permitted greenhouse gas (GHG) emissions, it will be necessary for electricity to become more decarbonized. It will also be necessary for some activities that are now fossil-fueled to run partially or fully on the cleaner electricity—a process referred to as electrification. Improved pricing policies are necessary to make decarbonization and electrification decisions effectively and efficiently.

This paper analyzes pricing reforms that could be considered by the state as part of its efforts to make effective and efficient GHG reductions. First, in order to achieve necessary global GHG reductions, it is important that California's carbon market link with other jurisdictions, like Quebec, that have comparable reduction goals and programs. Second, creating certainty in the minds of investors about the GHG reductions that will be required in California beyond 2020 will stimulate long-run infrastructure investments and research and development efforts that will reduce GHG emissions in the future. Third, individual electricity customers as well as small businesses will play a key role in cutting emissions. However, without a clear price signal, their usage is unlikely to change. To remedy this, legislation currently preventing 80 percent of the state's population from receiving any carbon price signal could be reformed, while the California Public Utilities Commission (CPUC) could improve the price signal being given to small businesses. Fourth, and perhaps most importantly, in order to meet long-term GHG reduction goals, California will need to transition its electricity customers to time-varying marginal-cost based rates, as the current disconnect between rates and costs prevents many of the most important actions consumers could and would take to reduce GHG emissions.

The better alignment of prices with costs is one key element to improving pricing policies. Costs include not only the private costs incurred by individuals and businesses that provide goods and services, but also costs to society – for example, the harm from air pollution. When air pollutants like GHG emissions are completely unpriced, a distortion in the market results. Those making emissions could perceive them as having no cost to society whatsoever. AB 32, California's landmark legislation that requires emissions to return to 1990 levels by 2020, addresses this market distortion and directs its Air Resources Board (ARB) to implement cost-effective policies. Policies being implemented to reduce emissions, including the state's AB 32 cap-and-trade program, begin to fix this zero price problem. However, there is substantially more that remains to be done.



An important part of the cap-and-trade program is its linkage with comparable jurisdictions. When California began designing its program, it was with the intent that the program would become linked or integrated with larger programs that included other jurisdictions having similar programs and goals. This is critical for achieving necessary global GHG reductions. It also is a mechanism that lowers costs and creates new economic opportunities to benefit from expertise in, and innovations for, reducing emissions. The Western Climate Initiative (WCI) is a regional group of governments that promote such linkages. California is a founding member, and it includes several Canadian provinces. These jurisdictions have worked to develop their individual policies in coordination with one another, in the expectation of eventual linkage. One of them, the province of Quebec, has proposed formal linkage with California. Following state law, Governor Brown has recently considered this linkage and found that Quebec meets the California standards for comparable goals and policies. **Linkage with Quebec should be encouraged**. It is a first step along a beneficial path that should eventually be well-travelled by many jurisdictions.

Another price-determining aspect of California's cap-and-trade program is the amount and duration of reduction requirements. AB 32 only specifies reductions through 2020, resulting in too little long-run investment in GHG reducing actions, including research and development aimed at commercializing innovative methods for future use**.** An Executive Order of the Governor currently mandates California's 2050 goal, but such orders can be amended or discarded by any sitting governor. Investors are therefore deterred from making investments due to unnecessary uncertainty about permitted GHG emissions beyond 2020**. If the state wishes to lessen this uncertainty and encourage investment, it should act soon to clarify state efforts to reduce GHG emissions beyond 2020**. ARB should consider addressing this uncertainty in its updated Scoping Plan, essentially a blueprint for AB 32 implementation due by the end of 2013, so that the legislature can confirm its intent soon thereafter. Further legislation need not be complex. It could be as simple as confirming a specific interim goal recommended by ARB, for example, achieving a 25 percent reduction in permitted emissions from the 1990 level by 2030. In order to eliminate uncertainty, the state should also consider directing the ARB to continue beyond 2020 with its programs to reduce GHG emissions gradually and steadily from year to year in order to achieve a sustainable level by 2050 and to maintain it thereafter. Actions like these raise the expected savings from reduced fossil-fuel usage from now through the life of any long-run investments undertaken, and will thus encourage important new long-lasting investments in GHG reducing infrastructure as well as valuable research and development efforts.

In addition to policies that affect prices in the cap-and-trade program directly, the retail pricing of electricity has very substantial effects on potential electrifications as well as other GHG-reducing actions. While prices in competitive sectors of the economy automatically adjust to the prices of GHG allowances that affect production costs, retail electricity prices are set through regulatory oversight of providers. In order to make efficient decisions about the usage of electricity, customers must face prices that approximate the marginal social cost of providing the services. To the extent that electrical service requires GHG emissions, over time the price per kilowatt hour (kWh) of service needs to include the cost of the GHG allowances used to provide it.

On the other hand, one does not want consumers to bear the burden of higher prices needlessly. Under the current program, retail electricity distributors receive free GHG allowances to sell at a state-run competitive auction. Under the law, they are required to use the auction proceeds for the benefit of their customers. **The CPUC developed a plan for returning the revenue primarily to residential ratepayers in the form of twice-yearly dividends per residence. This is intended to compensate them for electricity rate increases caused by the allowance system. However, state legislation (SB 695)** that had its roots in the 2001 electricity crisis **prevents the CPUC from passing the carbon price signal (the higher electricity price) through to the vast bulk of its residential customers.** The current system essentially prevents the CPUC from giving any carbon price signal at all to the 10 million households in its residential sector, thus completely eliminating a consumer's natural tendency to conserve energy in the face of higher energy rates. To remedy this market distortion, the legislature could modify this legislation, perhaps simply by clarifying the rate goals it wants the CPUC to achieve, relying upon CPUC expertise for the detailed rate design, and holding the CPUC accountable for achieving these goals. The current legislative constraint does not apply to the **small business customers** that will also qualify for assistance. **The CPUC could improve the method of assisting them by using a dividend approach similar to that intended for the residential sector.**

While a large part of the electricity pricing problem is appropriately incorporating the carbon price signal into rates, another independent part of the pricing problem is that it is difficult to set marginal-cost based rates and also to meet the total revenue constraint that enables a fair rate of return to the utility. A considerable problem of this second type is that **current electricity rates for all but the largest customers do not vary with time, whereas the cost of service varies by many multiples over the hours of any single day as well as over seasons.** This disconnect between current rates and costs prevents many of the most important actions that consumers could and would take to reduce GHG emissions. In order to connect rates with costs, **California should consider ways to transition its electricity customers on to time-varying rate structures that better align rates with marginal social costs.** There are many possible ways to do this. One of the most promising for addressing important fairness concerns is HOOP (Household On and Off Peak) pricing, in which volumetric rates are set at marginal social costs by time and a system of graduated fixed fees is used to cover the small portion of the bill necessary to cover fixed (non-marginal) charges.

In order to meet the state's longer-run emissions goals, the transportation sector must undergo a significant shift toward electrification. However, current electricity rate policy acts as a deterrent to vehicle electrification. This is because so many residential customers now face rates in excess of $.30 per kWh at night, whereas the marginal cost of providing night electricity is much closer to $.05 per kWh. Since the most convenient time for recharging electric vehicles is during the night, our current rates are discouraging one of the most promising methods for significantly reducing California GHG emissions.

In addition, there are numerous other efficient GHG-reducing actions that are being deterred by the time-invariant California system, and that would correspondingly be substantially encouraged by marginal-cost based time-varying rates. **One of these is grid storage batteries**, particularly those that might be located within a distribution network. The value of grid storage batteries depends not only on the technology, but on the differential between the electricity price when charging up the battery and when it is discharged. There is no incentive to store electricity if its price is the same when charging and when discharging, as it is for retail customers under time-invariant rates. If charging electricity has low or no GHG emissions (e.g. night electricity in California) and it is discharged to substitute for relatively high emission fossil-fueled electricity (fossil-fuel fired peaker plants), then the storage is also achieving substantial GHG reductions. Essentially the same logic applies to **clean distributed generation technologies like solar power**. Because current retail volumetric rates embed fixed costs within them, net metering policies sometimes overcompensate and sometimes undercompensate owners of solar installations. Marginal-cost based time-varying rates would align these incentives, and customers knowing that they will receive fair value are more likely to purchase such installations.

Finally, time-varying electricity rates can help to unlock the vast potential of reducing GHG emissions through **increased demand response resources**. Instead of using fossil-fueled generation to meet brief demand surges (or dips in the expected supply), retail electricity customers can often simply reduce briefly their demands. Under the time-invariant rate system, neither customers nor utilities have strong incentives to participate in these programs. But under marginal-cost based rates, end-users have much more incentive to reduce their consumption during demand response events. This in turn creates more incentive for the suppliers of appliance-control technologies—those that make consumption-shaving automatic and often not even noticed by the consumer—to develop and improve them. As the control technologies develop, it expands the range of circumstances under which demand response resources are practical to use. These resources involve substituting zero-emission resources for what are often high-emission fossil-fuel generators.

The collective reforms identified in this paper would help to ensure the continued support of Californians for meeting emissions reduction goals, and that California will serve as a model that encourages other jurisdictions to act similarly. Indeed, the GHG problem is only solvable with widespread global action to achieve goals comparable to those of California.

Intended Audience: This paper considers pricing policy reforms intended to guide California firms, residents and policymakers to a future characterized by far fewer greenhouse gas (GHG) emissions.

Electricity Pricing and Electrification for Efficient GHG Reductions

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I. What is Efficient and Effective Electrification?

When environmentally-concerned people think about ways to reduce greenhouse gas (GHG) emissions, they often think about "electrification"—instead of using a fossil fuel to power something (a vehicle, a building's water and space heating, a lawn mower, a kitchen stove, a clothes dryer), have it run on electricity. This idea is then conjoined with the separate idea of decarbonizing the electricity supply (no fossil-fueled electricity generation), so that the net result of implementing both ideas is a reduction in GHG emissions. Neither idea on its own is sufficient to ensure a reduction in GHG emissions. Electrification of something run on natural gas now will not reduce GHG emissions if the current electricity supply is primarily made with conventional coal-based generators, or any set of generation sources that emit more CO_2e for the electrical energy equivalent of the natural gas. Decarbonizing the electricity supply will not reduce GHG emissions if (perhaps due to its expense) more things are run on fossil fuels.

One important question thus becomes: when will the electrification of something actually reduce GHG emissions? We refer to this as the **environmental effectiveness** question. **When an electrification will reduce GHG emissions**, a second important question becomes relevant: is it worth doing? We refer to this second question as the economic efficiency question. If it is only possibly to electrify some particular thing at very great expense (e.g. change the heating system in a large existing building from natural gas to electricity), and the reduction in GHG emissions is minimal (the emissions from the electricity supply will only be a smidgeon below that of natural gas), then this would not be sensible—there would be a myriad of far less expensive ways to reduce GHG emissions. **Efficient electrifications are those that reduce GHG emissions at the least possible social cost**. **We consider in this paper policy changes that are needed for Californians to select effective and efficient electrifications within the next 10-15 years** as they proceed toward the state's 2050 GHG emissions reduction goal.

Electrification plays a key role in the report *California's Energy Future—The View to 2050* by the California Council on Science and Technology (CCST 2011), and the *Science* article written by some of the study's participants (Williams et al 2012). This work

[1] I am grateful to Next 10 for supporting this research, and to the members of the California Council on Science and Technology's project *California's Energy Future to 2050: Policy Issues* who provided important feedback during the development of this paper, especially Jane Long. I would particularly like to thank subcommittee members Jan Schori and Nancy Ryan for comments on earlier drafts, and Alejandra Mejia for her capable research assistance. My grateful thanks as well to Dallas Burtraw, Chris Busch and Robert Levin for their very valuable comments and suggestions on the completed draft.

considers whether it is technologically possible to meet California's long-run GHG emissions reduction goal—reducing GHG emissions by 2050 to 20 percent of the 1990 level (or to 85 million metric tons of CO_2e). The analysis concludes that the goal cannot be achieved by known methods if all reductions were to occur within California borders.[2] Only about 60 percent below the 1990 level can be achieved by known methods, and the remainder must come from innovations that have not yet occurred. This need for innovation is a key finding of this work, and how to foster it is an important policy question.

A further conclusion of CCST 2011 is that it will be necessary to "electrify everything" that is technically feasible, but it does not specify when any specific emissions reduction actions should be undertaken. The *Science* article suggests (p.58): "The logical sequence of deployment for the main components of this transformation is EE [energy efficiency] first, followed by decarbonization of generation, followed by electrification." Numerical costs were not considered as part of this analysis. In other words, this work considered the environmental effectiveness question, but did not consider the economic efficiency question. This paper considers further the findings of CCST 2011 and Williams et al 2012 in conjunction with the economic efficiency question.

Unlike the suggested deployment in the *Science* article, there are many electrification actions that are important to do soon, without waiting for further decarbonization of the electricity supply. There will be additional electrifications that become important as the electricity supply becomes cleaner, even if still far from being decarbonized. Yet policy makers have at best very limited knowledge of when and which electrifications are efficient to undertake. We wish to identify policy changes that will be needed before 2020 in order to use electricity intelligently as a means for reducing GHG emissions between now and roughly 2030, particularly for effective and efficient electrifications. An important aspect of this will be understanding how prices are used to guide these decisions, both within any given year and across the years, and the importance of having prices that are aligned with the marginal social costs of providing the priced goods and services. For example, to the extent that electricity service requires GHG emissions, the price per kWh of service should include the cost of the GHG allowances used to provide it. However, current retail electricity pricing policies often depart substantially from this alignment. We clarify these in the body of the report, and first clarify here our focus on the time frame from now until 2030.

California's AB 32 legislation mandates a 2020 reduction goal and gives primary responsibility to the California Air Resources Board (ARB) to implement policies that will achieve that goal in a cost-effective manner. These policies are largely in place and will be primary determinants of reductions from now until 2020. These include an array of

[2] It does not consider the equivalent reduction made within a larger area that encompasses California, as is expected to evolve over time as other jurisdictions adopt comparable goals. We discuss this later in the article.

policies including incentives, standards, and mandates that apply to both the public and private sectors of the economy. Some important elements are a cap-and-trade program for GHG emissions that will cover 85 percent of the state's GHG sources, motor vehicle standards that will gradually reduce GHG emissions from new vehicles, and a renewable portfolio standard for the state's electricity supply that requires renewable energy generation to comprise 33 percent of the state's supply by 2020. However, not too much research has been published at this point on policies that will be needed beyond 2020, and we wish to look beyond the AB 32 time frame to consider what is needed for the longer run.

At the same time, we must remain quite humble about anyone's ability to project human behavior too far into the future. Both technology and costs change in unexpected ways in response to human efforts at research and development. Sometimes progress is slow and steady, but sometimes there are major breakthroughs that redefine what is possible. Human behavior in the realm of politics can also profoundly affect economic possibilities. In particular for global warming, there is no point in California achieving its 2050 GHG reduction goal if it is the only jurisdiction with such a goal. It is the world as a whole that needs to achieve a similar goal in order to mitigate climate change. If the rest of the world does not eventually join with California in this task, one cannot expect Californians to continue the extensive efforts needed for what would become a meaningless long-run achievement. Relevant to this, California's long-run goal exists only as a gubernatorial executive order that could be eliminated or changed at any time at the whim of any sitting governor.

As California does establish linkages with other jurisdictions, as may happen through the Western Climate Initiative (linkage of California's cap-and-trade with Quebec is pending) or through national legislation, the possibilities for reducing GHG emissions expand and the cost of reducing GHG emissions to the combined limit becomes unambiguously lower. The larger market increases the rewards for research and development leading to innovations in GHG reduction methods, another vital aspect necessary for long-run success. Thus for multiple reasons—widespread participation, cost, and innovation—such linkages must be encouraged. Interestingly, if we get anywhere close to the worldwide effort that is needed, than it is doubtful that California would need to electrify everything by 2050. With a large number of jurisdictions all having appropriate reduction goals, it could be far less costly for the world to meet its goal if part of California's contribution (and that of other jurisdictions as well) paid for less expensive GHG reductions wherever they are available within the group. This would happen quite naturally under a linked cap-and-trade system, for example. Still, there is no question that very substantial emissions reductions must be made within California, and that this will require a cleaner electricity supply and increased electrification.

What we must strive for today is the set of policies that will keep us on a path beyond 2020 to the long-run objective of a healthy, sustainable atmosphere. We want policies today that fairly and efficiently reduce GHG emissions within California and any linked jurisdictions, that encourage other jurisdictions to undertake similar efforts, that encourage GHG-reducing innovations, and that are adaptive to changing future circumstances. Indeed, the success of current policies at fostering important innovations can itself be a key reason why we must remain adaptable to what will be discovered. We simply know too little about what conditions will be like beyond 2030 to try and specify today the details of policies intended to guide post-2030 decisions. Thus if AB 32 has led us to policies that guide decisions from 2012-2020, this paper can be considered part of the effort to plan policies to guide decisions over a somewhat more extended time frame, to include the 2020-2030 period. These will need to be solidified well before we actually reach 2020, so that firms, individuals, and local governments can intelligently plan how they will respond to them. A similar effort should take place by the mid 2020s to plan for the 2030-2040 period, and so on. This type of planning for significant time segments allows for both stability and predictability of policies within the segment as well as continually encouraging new knowledge and adaptability to changing circumstances as we proceed over the long haul.

While the AB 32 policies may be an excellent start, **unless additional actions are taken within the next few years California's GHG reductions will be lower and more expensive than necessary**. This is because the existing policies allow some important sources of economic inefficiency to continue, some of which will have significant adverse impacts even in the 2012-2020 AB 32 period. These sources are likely to have greater effects as we advance into the 2020s. By important inefficiency, we refer to GHG reduction methods that are substantially more expensive than necessary to achieve the reduction goals. **Perhaps most importantly, because these inefficiencies cause the cost of reducing GHG emissions to be higher than necessary, they jeopardize the support of Californians for continuing along the emissions-reducing path and discourage by their costliness other jurisdictions from joining in this critical task.** These inefficiencies unless corrected will also be substantial impediments to the electrifications discussed in CCST 2011 that are relatively inexpensive and thus important to undertake during the time period from now through 2030.

One of the most important of these is **vehicle electrification**, which **is being substantially deterred by inefficient electricity pricing. Electricity pricing inefficiencies are also retarding the development of smart grid demand response programs and various types of electricity storage facilities that would ease the integration of renewable generation sources and facilitate cleaner ancillary service provision. Electricity pricing policy also needs to be revised to be sure that the appropriate price signal of costly GHG emissions is visible to all electricity consumers**, so that everyone recognizes the value of reducing these emissions and will have an incentive to make efficient decisions including electrifications. An additional important inefficiency that affects not only electrification but all GHG reduction efforts is **the unnecessary uncertainty in terms of California governmental commitment to more specific levels of permitted GHG emissions in the years following 2020—under these circumstances, the private sector will not undertake enough long-run investment and research and**

development efforts to produce long-lasting GHG emission reductions—through major changes in plants, buildings or other infrastructure—that require to justify their expense savings from reduced GHG emissions over a long period.

We proceed as follows. In the next section, we review the importance of adding the efficiency criterion to that of environmental effectiveness, and clarify its implication to undertake the least expensive GHG reductions first. We then in section three explain the lack of sufficient or credible commitment in California that may inefficiently deter major investments in GHG reductions, and also an efficiency problem to avoid that is caused by the free distribution of GHG allowances to retail electricity distributors, and options that could solve them. In the fourth section we turn to the crucial role of electricity pricing in inducing GHG reductions, and why there are pricing difficulties in an electricity system with regulated or public monopoly retail providers. The fifth section shows that **the primary electricity pricing inefficiency that is deterring GHG reductions is the absence of widespread time-varying electricity rates based on marginal costs**, and discusses options like HOOP (Household On and Off Peak) pricing methods for solving this. A sixth section relates the absence of time-varying rates to efficient vehicle electrification, and to the availability of demand response and storage solutions that would both reduce the cost of integrating renewable generation sources into the grid, and encourage electrification through efficient use of them for ancillary services provision. A final section offers a summary and conclusions.

II. The Economic Efficiency Criterion

We have already defined the economic efficiency criterion as achieving the given environmental goal in the cost-minimizing way: choosing from among all GHG-reducing actions the least costly set. However, there is great uncertainty about the actual cost associated with many of the possible actions, and a central part of the problem is creating a regulatory structure within which those with the best knowledge decide these actions and have incentives to choose them wisely. Another important aspect of the problem is timing or sequencing: *when* should we undertake specific actions. These aspects have implications important for our task, and we clarify them first for the cost uncertainty, then for the decision-making problem, and finally for the timing issue.

We use a well-known 2007 study of U.S. GHG reduction costs by McKinsey & Co. to illustrate some of the great cost uncertainty—although any study similar in scope should convey similar uncertainties.[3] Suppose we ask how much reduction could be done at very little expense. McKinsey & Co. have estimated that about 40 percent of abatement to reach a stringent U.S. reduction target for 2030 can be accomplished at "negative" marginal cost, referring to actions that actually reduce costs rather than increase them. An example would be the purchase of a new energy-efficient refrigerator that more than repays its extra up-front cost through its reduced use of (GHG-emitting) electricity and lower bills.[4] They acknowledge uncertainty about the actual number of opportunities of this type, saying the range may be from 25 to 55 percent. Even given this very broad estimated range, many analysts are skeptical about the abundance of such opportunities for very "low-hanging fruit." If there is so much money to be saved, why have not people done it already simply out of self-interest? Perhaps there are other "hidden" but real costs that the McKinsey analysts could not take into account, like when energy-saving compact fluorescent light bulbs do not look well in chandeliers or work with security features intended to allow remote control of lighting. McKinsey and others think their estimated range of opportunities is accurate but that there are substantial "barriers" that prevent many people from recognizing them or from acting upon them, like lack of knowledge, limited funds for incurring higher up-front expenses, or myopia in terms of requiring too rapid a payback. Nevertheless it is fair to wonder the extent to which these same barriers will similarly prevent the same actions in the future,

[3] The McKinsey & Co. report is "Reducing U.S. Greenhouse Gas Emissions: How Much and at What Cost?", released in December 2007. It is instructive to see from the current vantage point of five years later that some expectations from it remain very useful while others have become outdated as the world has turned out differently. A more recent 2010 study of the same type, with similar qualitative findings although somewhat less optimistic, is by Bloomberg New Energy Finance "A Fresh Look at the Costs of Reducing US Carbon Emissions." This study is available at http://about.bnef.com/white-papers/us-mac-curve-a-fresh-look-at-the-costs-of-reducing-us-carbon-emissions/. We do not know yet which of its projections will be on the mark and which will miss it; the point here is simply that due to the uncertainty we expect some of both.

[4] McKinsey & Co. considered a 2030 goal that would bring U.S. GHG emissions down to 28% below 2005 levels.

even if efforts (perhaps costly ones) to overcome them are increased.[5] Not all of the uncertainty is by any means on the higher-cost-than-expected side; there could be terrific breakthroughs on something like battery technology to enable at little or no cost more energy-efficient consumer devices and other appliances. The truth is that we are simply highly uncertain about just how much GHG reduction can be achieved at little cost, both now and as we proceed into the future.

McKinsey & Co. were most interested in opportunities below $50 per ton of CO_2e abated, as their analysis suggested no need to undertake more expensive reductions: even their most stringent U.S. goal could be accomplished at marginal abatement cost no higher than $50 per ton. However, they did mention a number of abatement options that they would not undertake because they were too expensive. They specifically mention, for example, that retrofitting an existing building can cost as much as $80 per ton of CO_2e *more* than installation of the same features during initial construction—so in their scenarios, many technologically-possible retrofitting opportunities were substantially inefficient and therefore were not selected as ways to reach the 2030 goal that they were considering. Another review undertaken at about the same time, and specifically for California, reported estimates for using biomass for electricity generation at $190 per ton of CO_2e, and use of coal with carbon capture and sequestration (CCS) for electricity of $255 per ton.[6]

A particularly interesting high-cost option reported in the McKinsey study is solar photovoltaics (PVs), with an estimated cost per ton of abatement of $210. McKinsey & Co. also expected this figure to decline over time, through learning and technological improvement, to the $10-$62 range per ton by 2030. They were not alone either in this assessment. California's electricity is cleaner on average than that in the U.S. as a whole, and the California CO_2e reduction from displaced grid electricity is less and therefore the cost per ton of CO_2e reduced more. At about the same time as the McKinsey & Co. study, the California Public Utilities Commission (CPUC) estimated that the California Solar Initiative would reduce CO_2e at a net cost of $614.78 per ton.[7] However, these

[5] One 2009 study that addresses this issue is from the National Academy of Sciences, and estimates that behavioral interventions in U.S. households with no new regulatory measures could reduce their direct emissions by 20% over 10 years (and U.S. GHG emissions by 7.4%). While the authors emphasize non-financial interventions like media campaigns and information provision, financial interventions are an important component of the interventions and they do not include any cost estimates for these interventions. See Dietz et al, "Household Actions Can Provide a Behavioral Wedge to Rapidly Reduce US Carbon Emissions," in the Proceedings of the National Academy of Sciences, November 3, 2009, V106, N44, pp. 18452-18456.

[6] See p. 50, Table 11 of Jim Sweeney and John Weyant, "Analysis of Measures to Meet the Requirements of California's Assembly Bill 32," Precourt Institute for Energy Efficiency, Stanford University, manuscript dated September 27, 2008.

[7] See p. 4 Exhibit 2 of the California Air Resources Board Scoping Plan Economic Analysis Technical Stakeholder Meeting June 3, 2008, Appendix A "Review of Studies that Estimated the Costs of CO2 Emission Reductions" available at http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/060308/ce_appendix_a.pdf.

assessments could not foresee the extraordinarily rapid decline in PV costs that has occurred since those studies were completed. While as recently as 2008 the wholesale cost of solar modules was in the $3.50-$4.00 range per watt, by late 2011 this had fallen to about $1.00 per watt—largely due to the rapid development of manufacturing in China. Additionally, there have been declines in other solar cost components, particularly affecting utility-sized installations (as opposed to residential or small commercial rooftop installations). In March of 2012, both Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) were seeking approval of new PV contracts to build these installations at prices no higher than $.09/kWh—whereas solar prices were well over $.30/kWh in 2008. While these low prices include the effects of various subsidies available for PV installations, they nevertheless illustrate how uncertain we must be about which GHG-reducing actions are efficient, and how unpredictable changes in this set inevitably will occur over time.[8]

A final aspect that we will mention of the McKinsey & Co. work is the great regional differences in the number of opportunities at each of the abatement cost options that they consider. While they do not provide data by the individual states, they point out that according to their estimates the western region of the U.S. has 600 megatons of CO_2e that can be abated at $50 or less, whereas the southern region has 1130 megatons (p. 23). In a linked cap-and-trade program between these two regions with an aggregate cap requiring an abatement total of 1730 megatons, the equilibrium price will be $50 per ton of CO_2e (implicit in the McKinsey scenario) and no matter how the allowances are allocated to the regions the actual abatements will be 600 megatons in the west and 1130 in the south. If the west's allowance allocation would require a reduction of more than 600 megatons (therefore at a marginal abatement cost within the jurisdiction greater than $50), then it would be in the position suggested earlier for California in 2050—the west would buy additional allowances from southerners who will make profit from the $50 cash sale less the cost of the additional under-$50 abatement from its ample supply.[9] There would be no need for California to undertake the more expensive

[8] A review of recent developments in PV costs is contained in Bazilian et al (2013). Van Benthem, Gillingham and Sweeney (2008) show that solar subsidies like those available in California can be efficient if there are substantial "learning by doing" benefits that cannot be captured by the "doing" firm. Wiser and Dong (2013) distinguish between soft (non-hardware) and hard costs in residential PV installations, and present evidence to suggest further potential for cost reduction through learning that decreases the soft costs.

[9] When jurisdictions link, they will be very careful about establishing reduction goals with allowance allocations that represent reasonable fair shares for each jurisdiction. It is these shares, in combination with the unknown-in-advance least-cost solution, that determine who pays whom. Deason and Friedman (2010) in their appendix review fair share concepts that have been proposed for assigning GHG limits across jurisdictions. While it has been difficult at the global level to come to agreement about fair shares across both developed and developing countries, fair share agreements have been successfully forged by regional plans including the EU ETS, RGGI, and the WCI.

reduction actions that would be necessary if it were acting alone (which would have no point for this global problem). Trading opportunities can greatly reduce costs for both parties, and a major source of cost uncertainty is the speed at which California will gain trading partners over time as the rest of the world joins in the GHG reduction efforts, as well as the size of the cost reductions made possible by each additional trading partner. This example also suggests why California should look with favor on the actual proposed linkage with Quebec, one of its WCI partners.[10]

Given the high cost uncertainty of the many possible GHG-reducing actions, an important question is who is best suited to choose the actions undertaken. The varying locations of knowledge in the economy about the cost of reducing particular GHG emissions are the main reason why policy makers use an array of instruments from market-based decision-making to technological emission control requirements. People use energy in virtually every human activity, and no one can know all the reasons why people use it the way they do, or the costs to them of restricting their uses. This is the strongest rationale for policies like market-based solutions, in which individuals have the maximum freedom to make energy choices themselves and policymakers primarily set an aggregate limit and establish a CO_2e price high enough to achieve it. The price provides a guidance signal that affects all of the individual decisions in the market of energy users causing GHG emissions, and provides strong incentive to invent and to adopt less expensive methods of reducing emissions rather than emitting and paying for the required allowances.

The analysis in this paper assumes that California actions are based on the presumption that each jurisdiction should eventually accept responsibility for its fair share. That is why we do not consider inexpensive offsets that might be available from unregulated jurisdictions as a source of efficiency gains—while it is true that allowing such offsets would reduce the cost to California of achieving its fair share emissions goal, it fosters the larger harm of encouraging other jurisdictions to take advantage of California efforts without making comparable efforts of their own that are essential to achieving the necessary worldwide GHG reductions.

The text numerical example is not intended as a determination of fair share—it is only to illustrate that for any initial allocation the final (after-trading) emissions levels will be the same. If the west in the example is allocated enough allowances so that it could reduce by less than 600 megatons, the south would offer enough for some of them to induce westerners to sell them to the south. At western reductions less than 600 megatons, there are still western opportunities to reduce emissions at less than \$50—say \$40. But since total reductions must sum to 1730, the south would be forced to reduce by more than 1130 and thus to make reductions that are more expensive than \$50—say \$60. Since they are allowed to trade allowances, however, the southerner facing the \$60 abatement would be willing to offer the westerner with an allowance and an unused \$40 abatement opportunity some amount in the middle--\$50—to transfer the allowance. Both parties are better off by \$10, the aggregate cap is still intact, and the south would be buying from the west. Jurisdictions will work hard to ensure a fair distribution of the initial allocations of allowances, but for any initial allocation each jurisdiction improves its own welfare by trading rather than proceeding without trade.

[10] Indeed, the main overview webpage about the cap-and-trade program on the ARB website states explicitly "Designed to link with similar trading programs in other states and regions." See http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf. Comparable goals and rules must be established. In California SB 1018 requires this. On April 8, 2013, Governor Jerry Brown certified in a letter that the proposed linkage satisfies the SB 1018 requirements.

While the value of the price signal is extremely important to understand, the market-based method does not work well for all energy-using decisions. There are important reasons why we need building codes, appliance standards, regulators of local health hazards from emissions, regulators of monopoly utilities, and sometimes subsidies or penalties to provide additional incentives aside from the price on GHG emissions (e.g. to overcome some of the barriers to the energy-efficiency actions mentioned earlier).[11] As California under AB 32 will be relying heavily upon a cap-and-trade system to ensure that its aggregate reduction goals are achieved, it becomes crucial to understand that **the market allowance price under the cap-and-trade system signals the cost limit for distinguishing which GHG-reducing actions are the efficient ones to undertake, and which ones would be too costly.** This signal is important not just to those participating in the cap-and-trade market, but to all governmental decision-makers as well. If emissions can be readily reduced at say $25 per ton in the cap-and-trade market, then it usually makes no sense for a government decision-maker to require in the same time frame an additional reduction known to cost $50 per ton—again, the same aggregate limit could be achieved at less expense by an equal-ton tightening of the cap in the cap-and-trade market.[12] Conversely, any government decision-maker who has identified a policy action that reduces emissions at a cost of only $10 per ton, less expensive than the allowance market, would have a strong rationale for implementing it.

There is one final aspect of the efficiency criterion that needs clarification, and that is its implications for the timing or sequencing of emission-reducing actions. Imagine an annual cap for the cap-and-trade program that shrinks gradually from year to year until emissions reach a sustainable level, let us say a level like the 2050 goal for California of emissions 80 percent below the 1990 level. We accept for purposes of argument that the level considered sustainable is consistent with best scientific knowledge, and we focus on the path taken to get there. As the cap tightens from now until then, the annual emissions reductions must be greater and greater each year, and therefore one would expect that on the margins more expensive abatements would be included in the efficient set of actions each year. Therefore the allowance price should be expected to rise gradually from year to year due purely to this effect.

Other forces aside from the cap-tightening will also operate on any year's allowance price, and will cause the price changes to be less smooth than they might be otherwise. For example, the economy periodically and usually unexpectedly experiences recession periods with dampened economic activity. Within these periods, there will be a reduced demand for making emissions compared to an ordinary year, exerting some downward pressure on allowance prices. An economy that unexpectedly begins booming can do

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[11] Goulder and Parry (2008) provide a very good discussion of policy instrument choice.

[12] If the time frames are different, then it is possible that the $50 reduction could be efficient. For example, there might be substantial future cost reductions enabled by the learning from a demonstration project undertaken today. These future cost reductions could more than offset the extra current expense, making it efficient to undertake. We discuss efficient long-run decisions shortly.

the opposite, increasing allowance prices by more than the amount that would otherwise have been expected. Major unexpected innovations can have similar effects—if they are for methods that reduce emissions or increase energy efficiency they will exert downward pressure on allowance prices, and the opposite if the innovations increase energy demand and are much sought-after like popular electronic devices. These sources of variance aside, one would still expect that a goal of far fewer emissions to be reached gradually by reductions from now until 2050 would be associated with an allowance path of generally rising prices.[13] Gradually more expensive abatement methods should be expected to become members of the efficient set of actions as we evolve into the future.

The time path of allowance prices becomes important once we recognize that the set of emissions-reducing actions includes both short-run and long-run decisions. Short-run decisions refer to emissions-making energy usage decisions given the existing stock of capital (e.g. buildings, industrial plants, vehicles, machinery, appliances, infrastructure like electricity generators, bridges, airports and roadways, and other durable equipment). Long-run decisions refer to changes in the emissions-making capital stock over time (e.g. the new electricity generators to be built and the older ones to be retired, changes in the number and qualities of rail lines, changes in the vehicles in use, erection of new buildings and retrofitting or razing of older ones, and changes in appliances like refrigerators, air conditioners and washing machines). **Short-run emissions-making decisions in the market place are made based on the current allowance price.[14] Long-run emissions-making decisions** (i.e. the nature of our future capital stock in terms of how its usage will affect GHGs) **in the market place are made based on the expectations of the future price path of allowances over the life of the capital** (including the remaining life of existing capital). We want both short-run and long-run decisions to be those actions that are in the efficient set, whether or not these decisions are made in the market or by policy makers.

We have already suggested that efficient short-run abatement decisions are those for which the marginal cost per ton of CO_2e saved is no greater than the allowance price. The corresponding statement for long-run abatement decisions is somewhat more complicated, because typically the marginal cost of the abatement occurs while the capital is being built and the marginal benefits occur in future years when the capital is operating and fewer allowances are required because of the abatement. A simple example of a long-run emissions reducing action could arise when an older natural-gas

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[13] It is possible, however, that innovation could be so strong and successful in the emission-reducing direction that allowance prices would not increase at all, and could even decrease. This is exactly what has characterized the price history of many of our exhaustible resources. Rather than inflation-adjusted prices increasing as the known supplies are depleted, innovations have enabled us to identify and recover previously unknown and unrecoverable supplies like oil miles under the ocean, and to use production methods that yield more output for a given resource input. Thus despite our consumption the supply of the exhaustible resource can seem more rather than less plentiful.

[14] The California allowance price for one ton of CO2e during 2013 was $13.62 at the Feb. 19, 2013 auction.

burning furnace needs replacing at an industrial plant in the cap-and-trade program (e.g. a cement kiln). Two different replacement models might be available, one more expensive but more energy-efficient than the other. The marginal cost is the extra cost necessary to purchase the more energy-efficient furnace. There are two types of marginal benefits: less fuel is used when the furnace is operating, and there is a corresponding reduction in the number of allowances the plant will be required to submit.

The first benefit of fuel savings is there even before cap and trade, and it is equal in each year of the life of the new furnace to the amount of natural gas saved that year (compared to the other new but less-energy-efficient model) times the price of natural gas that year. However monetary amounts that occur in different years are not commensurate, and must be adjusted in order to be commensurate. These adjustments, called discounting, convert each future amount into its *present value*. Generally the further into the future that the amount occurs, the lower is its present value.[15] If the present value of all of the fuel savings over the life of the furnace exceeds the marginal cost, then the plant owners would choose the more efficient furnace because it increases the present value of profits. Let us assume that the present value of fuel savings is less than the marginal cost, so that absent the allowance requirement the firm would not choose the more energy-efficient furnace. Let us call this shortfall the marginal cost of abatement (the amount of the marginal cost that is not offset by the present value of fuel savings).

But with the cap-and-trade program, there is a second benefit to purchasing the energy-efficient furnace: the lower emissions mean that fewer allowances will be required each year, and the value of that reduction equals the number of reduced allowances times that year's allowance price. As with the fuel savings benefits, the plant owner will calculate the present value of all the saved allowances over the life of the furnace. The higher the allowance prices, the higher is the marginal benefit from the abatement achieved by investing in the energy-efficient furnace. If the marginal benefit of abatement exceeds the marginal cost of abatement, the plant owner will choose the more energy-efficient furnace.

An efficient long-run abatement is one in which the total present value of the allowance savings exceeds the total present value of the abatement costs. In the furnace example, the abatement is efficient if the present value of the allowance savings is greater than the marginal cost of the energy-efficient furnace less the present value of the fuel savings. For short, such an action may be referred to as having a positive net present value. For some purposes, this same test is referred to as a cost-benefit analysis, and efficient actions are those with positive net benefits. The details and issues involved in making these discounting or cost-benefit calculations go beyond the scope of this

[15] The present value of a savings S that occurs n years in the future with simple interest rate r is $S/(1 + r)^n$, or with continuously compounded interest rate r is Se^{-rn}.

paper, but a key point of our example is that the value of the benefits depends upon the expected future allowance prices. If future allowance prices are expected to be low, then a proposed abatement project is less likely to pass the efficiency test than if future allowance prices were expected to be higher. As long as the emissions reduction targets that determine the number of allowances are appropriate, then relatively low allowance prices are a good thing—they mean that we are able to accomplish our goals at relatively low expense.

To illustrate one practical context for this, the U.S. government conducted a study in 2010, updated in 2013, involving a large interagency team of economists from more than 12 different federal agencies to calculate the "social cost of carbon," a monetary amount to be used across agencies in valuing a one ton reduction in CO_2.[16] The original report selected a range of estimates for 2010, with the central estimates in the $21 - $35 range, a "high discount rate" estimate of $5, and an estimate of $65 representing an unusually adverse scenario taken from the 95th percentile of the distribution of estimated social cost values. These estimates were revised upward in 2013, with the central 2010 range estimated at $33 - $52, high discount scenario at $11, and the 95th percentile adverse scenario at $90. Each of these four 2010 calculations is associated with its corresponding time path out until 2050. For 2050, the revised values of the two central estimates were $71 - $98, with $27 for the "high discount rate" estimate and $221 for the 95th percentile adverse scenario. The price paths of these estimates over time may be the best available estimates of what allowance prices would be in a U.S. cap-and-trade program with mandated reductions commensurate with these social costs.[17]

Let us think back to the McKinsey & Co. report discussed earlier in this section, which reported that retrofitting an existing building could cost $80 per ton of CO2e *more* than abatement undertaken for the same building during initial construction. Without answering the question of when it will be efficient to require increased GHG-reducing

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[16] See Interagency Working group on Social Cost of Carbon, "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, United States Government, February 2010. See also "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under
Executive Order 12866, United States Government, May 2013. All dollar amounts are reported in 2007 dollars. The estimated social costs do not change very much as a function of emission mitigation efforts, largely because mitigation only affects the size of the yearly flow into the much larger and long-lasting atmospheric stock that causes the damage.

[17] These would also be the best estimates of efficient carbon tax rates were a tax policy to be used instead. In either case, this does not mean that the social cost estimates are correct, only that they are the ones most likely to guide U.S. policies. The revisions from the original 2010 estimates are due largely to changes in the three integrated assessment models (DICE, PAGE, and FUND) that underlie the government's method of estimation, and the models were updated to take better account of factors like adaptation efforts and damage from sea level rises. A thoughtful review by Greenstone, Kopits and Wolverton (2013) identifies important areas for future research to improve these estimates, including the way that potentially catastrophic damages are treated.

building standards, the above estimates imply that many of the technically-possible retrofitting actions will not become efficient at all during the 2010-2050 period (allowance prices not expected to be much higher than about $80, except if something like the 95th percentile adverse scenario comes to pass). Along the same lines, it is unlikely to be efficient to completely decarbonize California's electricity supply by 2050—rather than spend very high amounts to get rid of all natural gas-fired ancillary services, it is likely to be less expensive to replace coal-fired plants with other lower-emission plants in states making comparable reductions elsewhere in the United States.[18] Of course there are sure to be in California many retrofitting actions that can and should be done at relatively low cost, and some ancillary service provision that is both efficient and de-carbonizing.

The implication of this for California decisions made during the period from now through 2030 is that the only retrofitting actions that will be efficient are those that have, in present value terms, cost less than the value of the California allowances that they will save. If these allowance values are anywhere within the central range as calculated for the U.S. as above, this will exclude much technically-possible building retrofitting of the expensive type identified by the McKinsey & Co. While contractors and consumers can decide upon these actions on their own, the ones that we should expect to observe being undertaken will be the relatively inexpensive ones. **To the extent that California governments try to encourage retrofitting actions through educational campaigns or other policy actions, they have the responsibility to make sure they are recommending those that are in the efficient set**. **Similarly, the only infrastructure changes that should be set in motion by policymakers are those within the efficient set.** Otherwise they are causing the cost of reducing GHG emissions to be higher than necessary, which both jeopardizes support within California for continuing emissions reductions and discourages other jurisdictions from joining in.

Sometimes opportunities for efficient retrofitting may arise through leverage with independent events. For example, Mayor Edwin Lee of San Francisco recently introduced city legislation to require earthquake retrofitting of 3000 housing units.[19] If this does become a requirement, then the marginal cost of retrofitting actions to reduce GHG emissions *at the same time* goes down considerably (an important part of retrofitting costs is often the lost occupancy of the structure, which in this case would be occurring anyway). Local policy makers need to be alert to opportunities like this

[18] This does not mean that California would pay for them. Recall the discussion in note 7 of determining fair shares of allowance allocations across jurisdictions. In a U.S. national allowance system, California's fair share may turn out to be high enough that this burden falls elsewhere. Should a national system with jurisdictional shares become established, the emphasis within each jurisdiction turns to individual source compliance with their actual emissions (correct number of allowances submitted). The state jurisdictional origins of each allowance do not matter for compliance, just as money is accepted to pay for a purchase without considering its jurisdictional travels.

[19] See the news release from the San Francisco Office of the Mayor posted on February 5, 2013. It is available at http://www.sfmayor.org/index.aspx?recordid=248&page=846.

one, and to be prepared to inform building owners of specific GHG-reducing retrofitting actions (e.g. installing new heating systems, replacing old, leaky heating ducts) that might be especially beneficial to undertake during the seismic retrofitting.

One oversimplification in the description so far of efficient long-run decision-making is the suppression of some important types of uncertainty (aside from allowance price uncertainty) that also affect what is considered efficient. One type of uncertainty that particularly affects new innovative technologies is that it may not be clear before actually making the investment just how much emissions savings there will be, and what it will cost to achieve them. There can be very valuable spillover effects from "learning by doing" if the first investment is promising enough to lead to a second and so on. It is a common occurrence, as we conveyed earlier in the example of the increasing cost-efficiency of solar generation technologies, that an industry learns from its early risk-taking investments how to do it better with successive investments. In other words, the first investment may not actually pass a benefit-cost test but it can still be socially worthwhile if it leads to more mature investments that do pass these tests.

A market difficulty in this situation is that the learning benefits often accrue to firms different from the ones making the initial investments. In the case of investments in new electricity generation technologies, there may also be system learning benefits in terms of system control, dispatch, and uses of the new types of generation sources. Thus these positive spillover learning effects can mean that an investment that looks inefficient on its own may actually be efficient when it is an essential part of a time-successive industry-wide group of investments with collective benefits greater than collective costs. This is why it is not uncommon to have some form of subsidy to encourage the introduction and early adoption of promising innovative technologies, as we have done with solar generation and electric vehicles, even though no one necessarily expects the initial early investments to be efficient on their own. The state intends to use some of the revenues from its allowance auctions for this type of purpose (state law AB 1532).

Along these lines, one might question whether long-run decisions about new electricity plants made at the CPUC (or by the municipal utilities) consider a long-enough time frame to make efficient choices.[20] The CPUC has a process called the "Long-Term Procurement Plan Proceeding" within which it considers the need of the utilities for new generation either to replace existing generation or to supplement it. The proceeding that is ongoing currently has as its planning period the 2012-2020 time frame. This may be suitable for the increased renewable generation required by the state's renewable portfolio standard; these generating sources can be adequately planned and built within

[20] In addition to the CPUC and the municipal utilities, the California Energy Commission (CEC) also plays an important role in this process as the licensing agency for any new power plants 50 megawatts and larger to be sited within the state. For example, it is now finalizing regulations that will require the municipal utilities to report their progress in meeting the state's renewable portfolio standard requirements.

this time period. However, it may be too short of a time frame to consider adequately other types of generation sources, like the possibility of arranging for new baseload resources that might involve a new coal plant built with carbon capture and sequestration, or a new advanced-design nuclear plant like a pebble-bed modular reactor. Such plants could be shared with retail utilities from other states, and need not necessarily be located within California (carbon storage requires a location with suitable geologic conditions). Indeed, to minimize investment risk, any single utility might only contract for a relatively small portion of the plant's output (e.g. 10-20 percent). There might be very high learning value to everyone from some implementation of these type of plants, and if so it is a good argument for some federal assistance to be available to help with the costs. We are not taking a position here about their actual suitability, but only suggesting that we be sure we have a process that can consider them appropriately. This means an assessment based on estimated costs, potential learning and development value, and their potential long-run GHG reduction benefits.

III. Credible Commitment and Clear Signals Needed

In this section, we discuss two policy actions that have not yet been taken in California but that are necessary for its cap-and-trade program to work as intended and result in emissions-reducing actions that are from the efficient set. The first of these actions is the legislative extension of California's AB 32 GHG reduction goals to extend beyond the 2020 period in order to reduce unnecessary uncertainty about the amount of permitted emissions. The second action is to ensure that the cost of California's GHG allowances affects electricity rates similarly to the way they will affect prices of other important goods and services like food and transportation, and involves policymakers for California's municipal electricity suppliers, the CPUC, and the state legislature.

We have just reviewed the idea that actions to reduce GHG emissions involve both short-run and long-run decisions. Consider the long-run decisions that will be made from now through the early 2020s. Some of these decisions, as in the illustration of the cement plant that needs a new kiln, involve large upfront investments whose returns will not occur until a good number of years into the future. Cement kilns normally last from 20-40 years. Most existing coal plants, as a different example, were built before 1980 and are thus more than 30 years old, and they will continue to operate for some more years into the future. Virtually all of our operating nuclear plants were also built before 1980. Large commercial office buildings have similar characteristics, in that they involve very large upfront investment costs with returns that accrue for 30-50 years into the future. Research and development efforts also have this characteristic of significant upfront expenses on the expectations of profits from the successful GHG-reducing innovations during future years. For all new long-run investments of these types, the investors must weigh whether the upfront costs are justified by the future benefits. They consider if the extra cost of constructing a new cement kiln in a GHG-reducing way will be worth it, or more than repaid by the savings from a reduced need for GHG allowances. In the case of the building as opposed to the cement and electricity plants, the savings comes from not having to buy the electricity and/or natural gas that would embed the cost of the GHG allowances for it in its price (more on the latter below). In other words, these investors consider (either explicitly or implicitly) the likelihood of different allowance price paths over a 30-year period or more as an important factor in deciding whether or not to make a large "green" investment. Because of the way that future monetary amounts are discounted, expected allowance prices in the first fifteen years weigh more heavily than those in the years beyond.

We have already conveyed that there will be uncertainty about the future price path of allowances because the cost of abating to various levels is itself uncertain. But there may be a bigger uncertainty facing potential investors in a green California, and that is the uncertainty about the governmental policies that will apply at the end of 2020. There is a gubernatorial executive order in effect that mandates further reductions until 2050, but investors know that such orders can be revised or withdrawn at any time by a sitting governor. Consider a group of investors ready to build a large new building in

2017 for occupancy in 2020, and they could "green it" at a considerable expense that would more than repay itself at allowance prices that averaged $30 per ton of CO2e over the first 15 years of the building's life. Suppose then-current (2017) allowance prices were in the range of $20-25 per ton, up from the initial years, and that the legislature has been silent about post-2020 GHG emission reductions. Are the investors likely to undertake the green investment?

The above scenario is meant to suggest that with certainty about a smooth and steady GHG reduction path at least to 2030, and with allowance prices seeming to follow a gradually increasing path, the illustrative green investment may look reasonable. But once one considers the uncertainty, it may not be judged reasonable. The investors try to consider all factors that could affect the success of their potential investment in forming their expectations. Legislative disagreement, for whatever reason, could lead to an expectation that nothing will be done on that front. There could be debate, for example, if few other jurisdictions have joined in and pledged appropriate reduction goals—perhaps similar to the withdrawal beginning in 2009 of all seven U.S. states except California from the Western Climate Initiative (four Canadian provinces have remained WCI members).[21]

The tragedy of having too much uncertainty is that it impedes the long-run investments that are necessary for gradual transition to a sustainable future. A dilemma is that some of this uncertainty is real and unavoidable, and to the extent that this is true, there should be less green long-run investment than there would be if there was no uncertainty. However, it is unlikely to be the intent of California policymakers to have *unnecessary* uncertainty about California's reduction commitment beyond 2020, and this could be readily fixed: the unnecessary uncertainty reduced, while still maintaining adaptability to future events that are genuine sources of uncertainty. ARB is required to update its Scoping Plan by the end of 2013, and it should in that document at least suggest a range of reductions it is considering for the 2021-2030 period. This would in turn allow the legislature to confirm its commitment for ARB to continue reductions beyond 2020, and to add some specificity: perhaps direct ARB to recommend a more precise 2021-2030 schedule by a year certain (e.g. 2016), or perhaps itself identify a specific interim goal for 2030, like 25 percent below the 1990 level. An additional option would be to consider defining a goal that would increase if substantial additional "partner" jurisdictions adopt similar reduction goals (e.g. perhaps if a certain percentage is reached of global CO2e emissions that are within jurisdictions committed

[21] The withdrawals occurred following the U.S. financial crisis of 2008 and the onset of a severe recession, the same factors that also contributed to the abandonment of climate change legislation at the national level. The withdrawn U.S. states are Arizona, Montana, New Mexico, Oregon, Utah and Washington. The four Canadian province members are British Columbia, Manitoba, Ontario and Quebec.

to reduction of them).[22] The legislature should also confirm that the state authorizes and directs ARB, until further notice, to continue beyond 2030 with its programs to reduce GHG emissions gradually and steadily from year to year in order to achieve a sustainable level by 2050 and to maintain it thereafter.

There are other policies aimed at transforming the long-run energy-using capital stock that compensate partially for the absence of a credible specific commitment from California to GHG reductions beyond 2020. These policies may have independent policy rationales as well, but they also promote greater long-run emissions reductions. California's renewables portfolio standard (RPS), for example, effectively mandates that the stock of electricity generators be tilted toward new renewable generators, and the RPS can be extended beyond its current 2020 mandate for 33 percent renewable electricity generation. Note however that this policy only applies to very specialized investments like solar and wind energy generation and not coal with carbon capture and sequestration or nuclear generation. Similarly, new and stringent GHG building standards could substitute to some extent for market decision-making about buildings. These standards generally are mandatory for new buildings and often voluntary for existing buildings, as many varying circumstances affect the possible retrofitting of existing buildings. Nevertheless sometimes there are valuable spillovers that occur when mandated new building practices voluntarily get adapted to retrofits. Similarly, appliance standards and vehicle fuel efficiency requirements affect the transformation of the appliance and vehicle capital stocks.

But reliance upon these policies as a complete substitute for a long-term market-driven GHG reduction commitment would be substantially inefficient. Policymakers would be relying upon reductions in some specific situations that would inevitably cost more than reductions available but untaken elsewhere in the broad California economy. Indeed, perhaps the genius of California's approach under AB 32 is to have these sectoral policies that prod long-run emissions reductions but layer on top of them the overall cap-and-trade market, allowing the market to fill-in with enough other reductions to meet the aggregate goal, and to signal the price that helps both market and government decision-makers identify the efficient reduction actions. But to make sure that the market does its necessary long-run as well as short-run work, the best solution is a policy that removes the bulk of the 2020-2030 uncertainty about aggregate reduction goals, and continues trying to achieve these goals at the least cost. Simple actions of this

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[22] The shape over time of the efficient reduction pathway as well as strategic considerations in jurisdictional goal-setting are discussed in Deason and Friedman (2010). Australia (2011) in its Climate Action Plan announced a strategic 2020 goal (p. 14): "The Government has committed to reduce carbon pollution by 5 per cent from 2000 levels by 2020 irrespective of what other countries do, and by up to 15 or 25 per cent depending on the scale of global action." Similarly, the European Union has adopted a 2020 goal of reducing its emissions to 20% below the 1990 level, and has offered "to increase its emissions reduction to 30% by 2020 if other major emitting countries in the developed and developing worlds commit to undertake their fair share of a global emissions reduction effort" (see the EU website http://ec.europa.eu/clima/policies/brief/eu/index_en.htm).

type raise the expected savings from reduced fossil-fuel usage from now through the life of any long-run investments undertaken, and will thus encourage important new long-lasting investments in GHG-reducing infrastructure as well as valuable research and development efforts.

In addition to the need for a credible commitment to long-term reduction goals, **it is also crucial that the carbon price that is created gets translated properly as a cost component into the myriad of goods and services that it affects**. For example, a carbon price of $30 per ton of CO_2e will increase the price of an ordinary gallon of gasoline by about $.30 per gallon. Gasoline consumers will not see the allowance price directly, but they are still receiving the correct price signal: the extra $.30 in the gasoline price accounts for the impact of the CO_2e emission. In most sectors of the economy, the prices of goods and services will change as in the gasoline illustration, and the new price signals will appropriately reflect the cost of emissions associated with consumption of the good or service being purchased. **However, the way GHG allowances are initially distributed can, in some important cases, result in distorted price signals that are not reflecting the emissions cost.** The electricity and natural gas sectors are two of the most important sectors where **distortions are possible unless policymakers act to prevent them**.

California's system for the initial distribution of GHG allowances will require most emitters to purchase the allowances at auction. However, retail electricity distributors will be given allocations of allowances at no charge, with a mandate to use the proceeds of those allowances for the benefit of their ratepayers. Most of these retail distributors (specifically, the state's three investor-owned utilities) own little if any fossil-fuel fired generators themselves, so they are not expected to use these primarily to satisfy any allowance submissions that may be required of them. Rather, they will arrange for the sale of them at ARB-sponsored allowance auctions, and then they are required to use the proceeds for the benefit of their ratepayers. In magnitude, these proceeds will largely offset the extra costs to the utilities of the wholesale electricity that they buy (sold by fossil-fuel generators that must acquire the allowances in the market place to cover their emissions). The good news for ratepayers is that this method means that average bills will not change. But should there be no change in pricing, then this means that the 14.89 million California retail electricity customers (essentially the entire population) will be receiving no signal whatsoever about the environmental costliness of their consumption, and not a shred of additional incentive to avoid such costs wherever possible.

That this should be a concern is demonstrated by the treatment of allowances by utilities in another cap-and-trade program, the national Acid Rain program that distributes and requires SO_2 allowances from electricity generators across the nation. These allowances are largely distributed for free to the generators themselves. In some parts of the country, referred to as the restructured electricity areas, the wholesale markets are run on a competitive basis and largely if not entirely separated from the retail markets. In these restructured areas, both competition and self-interest force the generators to recognize that their free allowances are not really free: using them requires paying the opportunity cost of not selling them at market value to someone else. So in these areas, wholesale prices are generally higher by close to the market value of the allowances needed to generate the electricity, and therefore retail rates must also rise to cover and therefore signal to customers the environmental costs of the SO_2 emissions.[23] However, in the other areas of the country that are still served by the traditional vertically-integrated and regulated utility, there are typically no retail rate increases due to the allowances. This is because the generator and the retail utility are one and the same company, and there is no competition. The free allowances mean there is little change in the regulated wholesale cost (the regulator ignores the opportunity cost), and therefore there is little change in the revenue requirement on the retail side.[24]

California is a partially restructured state that, for the purposes of understanding the effects of the GHG allowance system, is just like the traditional regulated areas. While the wholesale prices to the retail utilities will rise by close to the market value of the allowances, those same utilities will be receiving revenue from the sale of the free allowances that essentially offsets the cost increase. If the regulators of these retail utilities (including the managers of the municipal utilities) act as do the regulators in non-restructured areas for SO2 allowances, then there will be little to no change in the retail rates and no signal nor incentive for the customers to avoid these environmental costs. Fortunately, California regulators seem aware of this dilemma and may act to

[23] Competitive conditions do not always allow output prices to rise fully by additional input costs. This depends on the price elasticity of both the demand and supply curves. In the electricity sector, because the long-run supply curve is relatively flat or highly elastic, almost all of the additional costs would be passed on to consumers. An important exception occurs if the regulation causing the additional costs only applies to a limited set of the suppliers. For example, if the additional input costs due to environmental regulation do not apply to competitors outside of the regulated jurisdiction, this may result in consumers buying only from the less expensive, non-regulated suppliers. However, almost all U.S. electricity is generated in the U.S. by generators subject to the same national SO_2 regulation. In the case of California GHG regulation, there are substantial imports of electricity from other western states but the regulation requires that the importer be subject to the same allowance requirement that would apply to an in-state generator. So in both of these cases, wholesale prices are expected to be higher by approximately the market value of the required allowances.

[24] Hanemann (2009), reviewing the effects of the SO2 trading program up through the year 2000, a period during which almost no restructuring had yet gone into effect, finds (p. 82): "…there was virtually no discernible effect in the price of electricity as a result of the Title 4 program." This does not mean that the regulated utilities do nothing in response to the allowance system. As intended, many take advantage of the system to reduce their own emissions at cost less than the market value of the allowances saved, and then they sell the extra allowances. This desirable behavior, however, does not fix the problem that retail customers have received no additional incentive to contribute to the SO_2 emissions reductions. Emissions in the regulated areas are not being reduced at least cost because of this (e.g. the cost of getting greater demand response during times of high SO_2 emissions might often be less than the cost of technological ways to reduce emissions) and other factors identified earlier (Carlson 2000).

avoid it. The CPUC in rulemaking proceeding R11-03-012 offers in its initial scoping memo the following description as one of seven policy objectives for the proceeding:

> *Preserve the Carbon Price Signal*
> *This policy objective refers to the extent to which, under a given proposal, the cost of carbon is reflected in rates, net of any allowance or allowance revenue allocation that might be used to directly offset those cost impacts.*

On the one hand, the title of the objective clearly recognizes the value of having retail customers receive the carbon price signal. However, its last clause seems to take away with the other hand the very signal it hopes to preserve, as if it might want to dampen the price signal as a way of offsetting the cost impact. There are many public policies that are poorly designed precisely because they fail to recognize that a distributional objective can be achieved by a means other than distorting price signals. In this case, legislative constraints are the main obstacles that stand in the way of the CPUC intent to preserve the price signal and to achieve distributional fairness.

There are alternatives that will allow both the proper carbon price signal and the full offsetting of the cost impact to customers. These alternatives work by achieving the distributional objective not through price subsidies but through lump-sum payments that do not change prices. The CPUC has in fact shown great skill in recognizing this clearly, and has made one important component of its policy an action consistent with it: a dividend policy. The CPUC has decided to require that a substantial portion of the proceeds from the sale of allowances be fully returned to customers in the form of a semi-annual dividend of equal amount to each metered residence.[25] Essentially, the higher wholesale cost of electricity (due to generators needing to purchase GHG allowances) is passed through to commercial and industrial electricity consumers, and then this extra cost is offset by a dividend credit to the residential consumers who will be bearing most of its burden. While the prices of goods and services produced in a GHG-intensive manner will increase, thus correctly signaling their true economic costs, consumers will have been given a compensating income adjustment (the dividend) that allows them to adjust their consumption choices in whatever manner is best for them. A dividend equal to the average extra cost caused by the allowance system (in the commercial and industrial sectors) leaves the average residence better off than it was initially, and it discourages GHG-intensive consumption choices.

The annual value of these allowances and the size of the dividend depend upon the allowance price that will be set by market forces. For 2013, the utilities under the CPUC jurisdiction will receive 65,410,680 free allowances. Due to the shrinking aggregate cap,

[25] While the proceeding is still ongoing, the CPUC has decided certain aspects and reported them in Decision 12-12-033 dated December 20, 2012. The general idea that California might return its allowance revenue from the cap-and-trade program directly to consumers through a dividend has been discussed previously. See, for example, Burtraw and Parry (2010), and Burtraw, McLaughlin and Szambelan (2012).

this number will decrease gradually to 54,482,513 for 2020. It is expected that allowance prices will be between $10 (the ARB-set minimum) and $40 (the market price above which ARB will sell additional allowances from a reserve). For 2013 allowances, the market price as of the Feb. 19 auction was $13.62. This means that the total value of the CPUC-jurisdiction allowances is $891 million, and were all of this to be passed back to the approximately 10.2 million residential customers, the annual dividend would be approximately $87 per residence (two semi-annual bill credits of $43.50 each).[26] Were allowance prices to reach $40 by 2020, the value of the annual dividend would increase to $214 per residential customer.

However, not all of the revenue from the sale of allowances will be passed back to consumers in the form of a dividend. An egregious exception is due primarily to state law AB 1X passed in 2001 during the state's electricity crisis, which essentially forbids the passing on of any cost increases to the rates in Tiers 1 and 2 of the multi-tiered residential system (with higher rates on successive tiers). This was modified slightly in 2009 by SB 695 that allows annual cost increases equal to the consumer price index plus one percent, but not more than five percent. Because of this constraint, the CPUC is not able to allow all residential rates to rise by the cost of the residential GHG allowances even though it would provide lump-sum compensation in the form of a higher dividend amount. The constraint would force all of the cost increase to be borne by the tiers above the first two, a minority of total residential consumption.[27] There is already enormous mispricing of electricity caused by this legislative constraint that has stayed in effect well beyond its intended usefulness for crisis management. For the exact same increase in consumption of one kWh, some households are now charged three to four times the amount as other households and these charges are unrelated to the actual marginal cost of providing the service.[28] No income differential between these households exists that might be entertained as a rationale for such differences—in fact, there are separate provisions that provide assistance to low-income (and medically needy) households, and this assistance is generally in the form of a 20 percent discount on rates.[29]

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[26] There is a behavioral issue of whether consumers will respond differently to an actual separate semi-annual dividend check or a semi-annual bill credit. The CPUC considered this (pp. 119-122 of Decision 12-12-033) and tentatively decided that the administrative savings from issuing the rebate as a bill credit were quite significant, and that the behavioral differences are likely to be small as long as the bill credits are infrequent.

[27] Borenstein (2012) in Table 1, p. 62, finds that 64% of residential consumption on the standard tariff is within Tiers 1 and 2, and only 36% within Tiers 3-5.

[28] For example, in 2009, PG&E had a baseline rate of $.115 per kWh and a Tier 5 rate of $.441 per kwH. By early 2012, lower costs narrowed this gap with $.128 baseline and .336 Tier 5. Its residential tariffs are available at http://www.pge.com/tariffs/electric.shtml#RESELEC.

[29] Several scholars have investigated the relationship between income and energy usage. See, for example, Herter (2007) who finds a correlation (R^2) in California of only .079 between income and summer usage. This is not very different than the results reported by Sanquist et al (2012) using a nationwide sample of residential households and finding a simple correlation (R) of .26, with large standard deviation around the mean at any income level (p. 357).

Thus while the CPUC would prefer to treat residential GHG allowance costs exactly the same as commercial and industrial, under current legislation it cannot. Rather than unfairly placing the entire residential burden on a fraction of its households, **it has** instead **chosen to use the allowance proceeds to hold residential rates constant**. **In other words, it has chosen to send no GHG price signal at all to its entire residential sector of 10 million households** (containing about 80 percent of the California population)**.**[30] **This is a problem that needs a legislative remedy soon.** Because rate design is a very complex task, it is preferable for the legislature to specify the rate-making goals that it would like the CPUC to achieve, leave the details to be worked out in CPUC public proceedings that enable substantial stakeholder participation and use of technical expertise, and hold the CPUC accountable for achieving the set goals—just as the legislature has done with AB 32 and ARB. We discuss residential electricity rates further in Section V.

There are other provisions of the CPUC decision that further reduce the amount of allowance sales proceeds available for the consumer dividend, but to the extent that they are temporary measures they may have worthy transitional effects. One provision arises from concerns about the effects of GHG allowance costs on industries with production activities that can be relocated out-of-state where there are no comparable GHG costs (either the firms themselves move, or out-of-state competitors replace them). This is sometimes referred to as the leakage issue, in which California GHG emissions would decrease only to be offset by increased GHG emissions elsewhere. Not only does this achieve nothing environmentally, but it is no one's intent to have state policies that drive out jobs and industry. ARB has addressed this issue by providing free allowances to emitters in industries it considers as "Emissions-Intensive and Trade-Exposed" (EITE).[31] Presumably this is a temporary problem that will be solved by more global participation of other GHG-reducing jurisdictions, and ARB has scheduled decreasing amounts of free allowances over time for most of these entities (but not those at "high" leakage risk, and even those at "low" leakage risk are scheduled to receive 30 percent free allowances in 2020). Because the number of free allowances does not depend on an entity's then-current emissions, it does not interfere with the incentives to reduce emissions cost-effectively. The entity can buy additional allowances or sell unneeded ones at market value, and it will therefore reduce emissions whenever it can do so at a cost less than the market value of the freed-up allowances.

State legislation (SB 1018) passed in 2012 directs the CPUC to credit allowance revenues "directly to the residential, small business, and emissions-intensive trade-exposed retail customers…." The CPUC and the legislature reason that other industries besides those

[30] In 2011, California had 13,002,980 residential customers according to the U.S. Energy Information Administration, Table T1 at http://www.eia.gov/electricity/sales_revenue_price/. Table T6 on the same page lists 10,098,005 or 78% of these customers as served by the three large IOUs and thus under CPUC jurisdiction

[31] For further discussion of this idea, see Morgenstern and Moore (2010).

identified by ARB may be equally trade-exposed and equally emissions-intensive but indirectly through the electricity they purchase. It intends to use some portion of the revenue from allowance sales to buffer these industries similarly to the way ARB has provided free allowances to the EITE entities that are direct emitters. The methodology for doing this is still under development, and we hope that it will continue the principle of assistance in a form that maintains full incentives for these entities to reduce their emissions cost-effectively.

The legislature also requires that small business be given some portion of the allowance revenues as a direct credit (although it does not define small business). The CPUC recognizes that small businesses are overwhelmingly not of the EITE type, but due to the legislative requirement has decided to treat them somewhat equivalently to the “low risk” EITE entities (100 percent free allowances initially declining to 30 percent free in 2020). However, the CPUC reasons that administrative concerns will cause the form of this to be in terms of a price subsidy, muting the incentives for GHG reduction that it would prefer to preserve. In this case, the CPUC may not recognize that it does have administratively simple alternatives that could meet both the direct credit requirement and preserve the price signal. It is true that the same dividend-type credit that it uses in the residential sector cannot simply be applied here: whereas there is a good argument that each residence should receive the same dividend, the same cannot be said for small businesses that vary in size from “mom and pop” enterprises to those with scores of employees. However, the CPUC can certainly treat the small businesses like the residences with a semi-annual award of these credits, so that they do not occur as immediate price offsets to a current bill. Furthermore, the CPUC could go a step further and classify the small businesses into, say, ten categories by amount of historic (2012) annual consumption, and then assign proportionally higher dividend amounts to each successive category—so that no entity would be receiving an amount calculated from its current volumetric consumption.

While there is more to say about what it means to have an appropriate carbon price signal—exactly where in rates should it arise—we save that discussion for the later section on electricity pricing, as the main points of this section have been made. If California wants to achieve its long-run emissions goals with the support of its population, it needs to do so at least cost. To induce Californians to undertake crucial long-run investment decisions, the state government needs to act soon to reduce the uncertainty about the magnitude of reductions that will be required in the 2021-2030 period and confirm that GHG reductions will continue to be required indefinitely beyond 2030. A credible commitment to more specific levels of permitted emissions provides investors with more certainty of returns through saved allowances and will encourage the investments. Furthermore, the overseers of the state’s electricity distribution entities should act to ensure that electricity prices signal the cost of the allowances necessary to produce it. There is no inherent conflict between their doing so and returning the proceeds of their free allowances to customers, but it would be a mistake to use the method of unchanged rates that characterizes the practice of utility regulators in non-restructured states for SO_2 allowances. Retail electricity prices should be allowed to rise commensurately with increases in wholesale electricity prices, and any return of the revenue from sale of free allowances to ratepayers should be done in lump-sum amounts like a semi-annual dividend or bill credit that is not simply proportional to consumption. The CPUC has made a very promising start on this with its dividend policy, and it could do even better by applying a somewhat-similar policy to the required credits for small businesses. However, the current situation in which residential customers receive no price signal at all should be revisited, and this likely requires some legislative relaxation of the constraints of SB 695.

IV. The Retail Electricity Pricing Problem

Current California retail electricity pricing policy will not lead to effective and efficient electrification decisions in the 2015-2030 period. To clarify this, we explain in this section why it is difficult in general for retail electricity prices to be set at efficient levels, and options to improve this situation. Then in the following section we explain why this is such a significant problem for achieving efficient GHG reductions, with options to address this specific issue.

In order for prices to give appropriate signals as to the sensibility of what and when to electrify, they must be equal to their marginal social cost. In reasonably competitive situations, this happens naturally as a result of the competitive forces. But in monopoly situations that largely characterize the California retail distribution of electricity (one retail utility per service area), it is difficult to achieve marginal-cost prices. The retail electricity distributor has generally declining average costs (AC) of service, because so much of the expense of the business is the large fixed cost of constructing the distribution system. This is the so-called "natural monopoly," in that it would not be sensible to have competing firms erect multiple distribution systems to serve the same geographic area. Thus these companies are generally either regulated IOUs or municipal utilities.[32] But whenever average costs are declining, marginal cost (MC) is below average cost (AC). Pricing at MC is required for efficiency, but MC pricing will not raise enough revenue to cover the average cost of service and keep the company whole. The most common response has been to set prices at AC, despite the inefficiency.

Economists have considered this problem at many times beginning early in the 20th century, and have proposed various pricing systems that both meet the "revenue requirements" and improve efficiency. However, none of these proposals have been widely adopted, as various administrative and other practical obstacles to using them have rarely been overcome. Nevertheless from the perspective of the 21st century, the efficiency problems with the prevailing pricing systems have become substantial, and they threaten our ability to respond intelligently to the severe challenge of climate change. The primary source of the inefficiency has to do with very large differences in the marginal costs of service by time of day, whereas very few utility customers except for the largest ones have rates that signal these important marginal cost differences. This is compounded by any unpriced externalities of electricity generation like air pollutants that should be counted as part of its marginal social cost, and that also vary greatly by time of day.

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[32] In many jurisdictions outside of California, authorities have separated into different entities the "distribution wires" company that remains a monopoly but provides no retail service itself, and then competitive retail entities that sign up customers, procure the electricity for them, and deliver it via an open-access system through the distribution wires company. This is an alternative way of trying to rationalize and to improve retail electricity services, and it deserves further study. However in California this would require major institutional reform that is not under consideration at this time.

One of the simplest pricing solutions designed for the residential sector is HOOP (Household On and Off Peak) pricing. The essence of it is that volumetric rates can be set properly at the time-varying social marginal cost level, and the remaining balance of the revenue requirement can be collected through a set of graduated connection fees that are largely fixed from the customer's point of view and determined primarily by fairness considerations. California policymakers have made clear their interest in fairness issues as they relate to electricity pricing. The HOOP idea that addresses both efficiency and fairness is explained in technical detail in Friedman (2012). It overcomes the fairness objections to an older idea called the "two-part tariff" that relies upon a uniform connection fee and thereby raises the bills of low-usage consumers and lowers the bills of high-usage consumers. The graduated connection fees are similar to the idea for small business credits presented in the prior section: classify customers into a relatively small number of categories by average annual consumption, and then assign one fee to each category with the fees gradually rising as one moves from lower-consumption to the higher-consumption categories. It is possible (if desired) to set fees to be negative (i.e. credits) for the lowest-usage categories and for special customer categories like those qualifying for low-income assistance, and it is also possible to set them so that there will only be minor bill changes from the system it is replacing.

As one example of a HOOP pricing plan, Friedman (2012) uses a simple time-of-use plan with a peak period price of $.30/kWh that applies during 2-7PM on nonholiday weekdays, and an offpeak price of $.05/kWh that applies during all other hours. These rates are illustrative of those that would come out of rate proceedings like those held by the CPUC that require the calculation of "marginal cost revenue" (the revenue that would be raised if rates were set at their marginal costs). HOOP plans may use more dynamic rates than these, e.g. they could include a critical peak price that would apply only on a very limited number of days per year when the system capacity is unusually strained. For any system of time-varying marginal-cost based rates, the "marginal cost revenue" raised by the volumetric rates will generally be less than the required total revenue that covers fixed costs and enables the utility to make a fair rate of return. In the example, actual revenue raised by the current time-invariant tiered-rate plan averaged $860.64 per year per residence in a statewide representative sample. For the identical consumption, the average HOOP peak and offpeak revenues per year per residence are $342.72 and $268.80, or a total marginal cost revenue of $611.52. This means that the difference between the required average revenue of $860.64 (to make the HOOP plan revenue-equivalent to the current tiered rate system) and the marginal cost revenue of $611.52 is $249.12 per year per residence, and the graduated fixed fees per residence are assigned by equity or fairness principles to raise exactly this average.

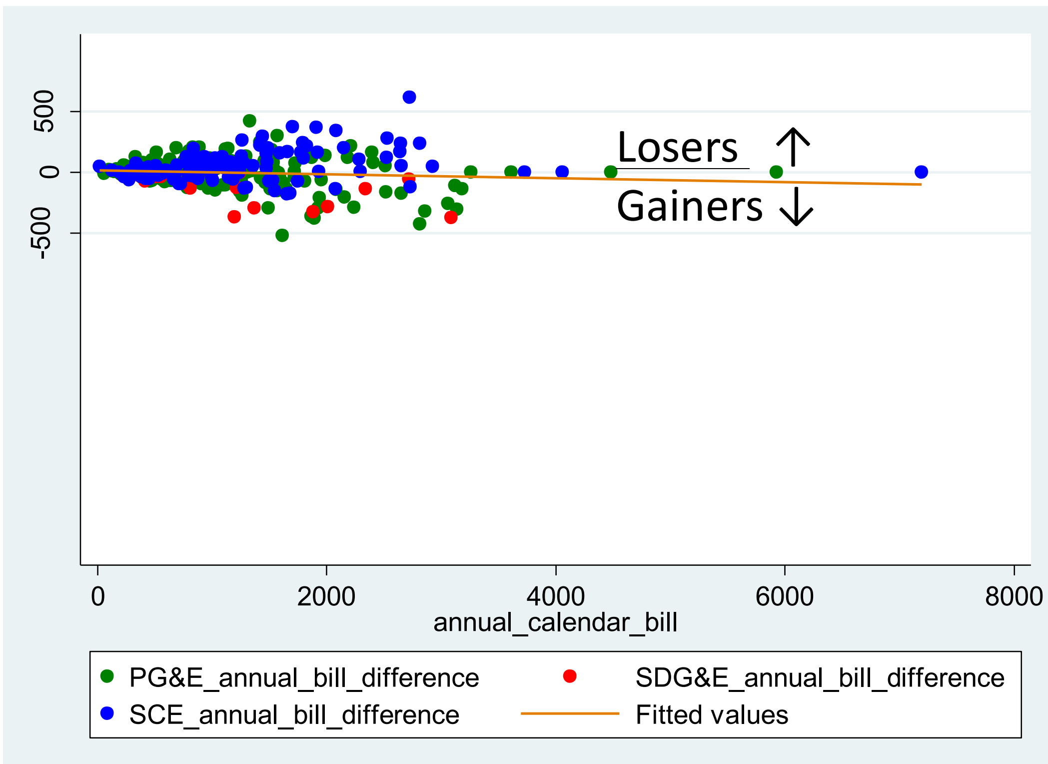
To assign the graduated fixed fees, residences are first classified into ten major groups by annual total usage (0-2000 kWhs, 2001-4000 kWhs, 4001-6000 kWhs, etc.). Most residences are in one of the first three groups, and the number of residences per group decreases substantially with successively higher usage groups. The annual usage categories are chosen to be broad enough so that consumers are generally unable to alter them by the way that they respond to the short-run marginal cost signals of the time-varying HOOP rates (e.g. shifting the time a dishwasher is run from the peak to the offpeak can save substantial money and reduce emissions, but it has no effect on annual usage).

One of several differing equity principles that can be used to calculate the graduated fixed fees in this HOOP example is designed to minimize "bill shock" (holding usage constant, bills from a new system that are significantly higher than those consumers are used to receiving will be perceived as unfair). The HOOP method then assigns the fixed fee to each group that, along with the marginal cost revenue, raises the same amount of revenue that group contributed under the old system. This results in fixed fees for the three lowest usage groups of $3.18, $8.04, and $12.74 per month, increasing up to $100.24 per month for the highest usage group of 18,000-20,000 kWhs per year.[33] The average residence within each of the 10 categories has no bill difference compared to the original time-invariant system. Figure 1 below shows a graphical representation of this system in comparison to the time-invariant system—the dollar amounts of new bills cluster fairly tightly around the old bills, with no systematic gains or losses as a function of consumption levels. When all of the bill differences are ordered from the biggest gainers to the biggest losers, the average bill differences within each of the deciles 10-90 (80 percent of the population) are all within 10 percent of the old system bill.
The above exposition of HOOP pricing emphasizes its fairness by comparing the HOOP plan to the time-invariant tiered plan holding each residence's usage constant. But of course a main motivation for switching to time-varying rates is to encourage customers to alter usage in a way that makes them better off and is also good for the environment. The time-shifting example of running the dishwasher during the offpeak period rather than the peak period illustrates that, and in the next sections we will expand upon the importance of the behavioral changes that should be expected with better pricing. But HOOP pricing offers another advantage: it can encourage long-run residential investment in emissions reductions better than many other rate designs. Whereas HOOP is designed to have short-run decisions determined by the time-varying volumetric rates, long-run decisions will be influenced both by the volumetric rates and the prospects for changing categorization by annual usage. That is, annual usage categories that span 2000 kWhs are almost impossible to change by altering short-run behavior, but they can be altered by new long-run investments in the appliances of the residence (e.g. a solar installation, a new energy-efficient HVAC system). The default HOOP classification procedure is to allow reclassification only slowly, as would be the case with categorization based on a two or three year historical average annual usage

[33] An alternative equity principle that can be used to calculate the graduated fees and produces somewhat similar fees is proportionality: each group by usage category is assigned a fee that is proportional to the historic average annual usage of that group. With either equity principle, residences that qualify for low-income assistance are assigned fees (credits) separately in Friedman (2012). Under HOOP the same total revenue is collected from the entire low-income assistance group as under the current time-invariant system, and since this is less than marginal cost revenue, the low-income group is generally assigned graduated monthly credits that vary by usage category rather than fees.

for the residence. But recall the earlier discussion of behavioral barriers that make it difficult for individuals to recognize the opportunities from these important pro-environment investments. We suggest an encouraging approach to such investments by offering speedy reclassification for them—making the benefits of such investments more visible and prominent than they are under the current time-invariant system.

Figure 1: HOOP Residential Electricity Pricing is a Fair System that Uses Time-Varying Rates



Other methods besides HOOP pricing have also been proposed to make an attractive system of time-varying rates close to marginal costs. For example, Borenstein (2012a) proposes offering customers two options, a time-varying pricing system and a flat rate system where the flat rate is always the weighted average of the time-varying rates. Imagine that customers begin on the flat rate, but then some realize that their bills will go down on the time-varying system and they switch. This will cause the rate in the flat rate group to rise modestly, as the remaining customers in it have a slightly higher weighted average of the time-varying rates (it is the below-average customers that have switched). But this in turn will cause additional customers to switch on to the time-varying rates, and so on until eventually everyone has joined the time-varying system. The time this will take to achieve depends on how quickly the rates are adjusted and how quickly customers respond to these adjustments. As there are understandable pressures for slow and gradual adjustments, this should be understood as a process occurring over a number of years. Faruqui and Palmer (2011) have additional time-varying rate design ideas based on their review of 109 different tests of time-varying rate plans from Europe, Australia and North America.

The point of this brief section is that in the California electricity sector, marginal cost pricing at the retail level does not happen naturally as it does in competitive sectors, and there are reasons why it is difficult to achieve in practice. Nevertheless, very substantial inefficiencies can arise if there are large differences between the rates and marginal costs, and numerous practical rate designs can be used to substantially reduce or to eliminate these differences. The next section suggests that the problem of large differences between rates and marginal costs is exactly the case in California, and that fixing this is very important to a successful and sustained reduction in GHG emissions.

V. The Importance of Having Widespread Time-Varying Electricity Rates[34]

Many California residences face rates of $.30-.40 per kWh even in the middle of the night, when the marginal social cost of that electricity is generally below $.05 per kWh. Why does this matter? As one example, CCST (2011) concludes that vehicle electrification will be an important method for achieving California's GHG reduction goals. The ongoing and increasing worldwide production by automobile manufacturers of both electric and plug-in hybrid electric vehicles is evidence that their economic viability is well within the practical. But adoption of them at a large scale within California is unlikely to happen under current electricity rates that make such electrification 6-8 times more expensive than it should be.

Many economists have written about the importance of having time-varying retail electricity prices, and the case is compelling. The standard argument for this has focused on the high and sometimes extraordinarily high costs of meeting peak period demands—costs that upon occasion exceed $1.00 per kWh—while consumers receive no signal other than their usual rates that in California average $.17 per kWh. But now the challenge of mitigating climate change adds to this a focus on low offpeak rates and the opportunities that they offer for efficient electrifications, as with the electrically-fueled vehicles example above. Whereas in the 20th century one could reasonably object and point out that meters then in place could not tell time, that is no longer the case in California. As Friedman (2011) puts it, "Time-invariant rates are a historical anachronism, a system of grossly inefficient subsidies and penalties that no longer has a legitimate basis for continuation. It seems unconscionable for us to continue to subsidize peak-load consumption when its social costs are so great, and to penalize off-peak consumption when it holds so much promise as a method of environmental improvement." The particular cost differences within a day may change substantially over the years as we modernize and decarbonize generation sources (e.g. with increased solar and wind generation), and the point is to be sure that rates signal these cost differences appropriately so that consumers can respond intelligently to them.

Within the United States, it is not uncommon for large industrial electricity customers to be on some form of time-varying rates. For purposes here, we consider as time-varying any system with rates that depend upon the time of day. These encompass many rate designs from (a) the simplest division of a weekday into a peak and offpeak period, to (b) a very modest but valuable extension of this that allows a small number of days per year to be designated as "critical peak" with higher peak period rates than usual, to (c) much more dynamic "real-time pricing" designs in which price may vary every few minutes in accordance with the market wholesale price necessary to provide it. However, it is very unusual for residential customers or the bulk of commercial customers to be on any time-varying rate. For example, only two states have more than

[34] This section draws heavily from Friedman (2011).

1-2 percent of residential customers on time-varying rates: Arizona and Connecticut. Connecticut is a particularly interesting example because its Department of Public Utility Control (DPUC) requires that residential and commercial customers transition to time-varying rates. The transition began with the largest users in 2008, and is adding those with decreasing usage levels over the successive years.[35] This type of phase-in might also be useful in the California context. Connecticut's phase-in has been slow as the necessary meters were not yet in place, but California has the meters and thus could proceed with a faster phase-in.

In addition, new evidence has become available that shows a further magnification of this problem. The large time-varying marginal cost differences that have been observed for many years now, as reflected by California wholesale electricity prices that commonly will be around $.02 per kWh in offpeak periods (and sometimes much lower) and 2.5 times this or $.05 per kWh in peak periods (and sometimes much higher), do not include any costs of GHG emissions. But **GHG emissions per kWh also vary substantially over time of day as well as seasonally.** Because our interest here is encouraging price responsiveness, the *average* emissions during any particular hour are not relevant to how price-induced changes in the quantity of electricity consumed at a particular time affect GHG emissions. The crucial factor is the emissions from the *marginal* generation sources—those that have been brought on line last, and the next sources to which we would turn if additional electricity is needed. **Any changes in California electricity consumption affect GHG emissions through their effects on marginal generation.** Several studies have been done on how changes in California electricity usage during each hour of the year change GHG emissions during that hour. They find more GHG-intensive electricity during the peak hours and during the summer period, and it is critical to have retail prices that reflect or signal these differences as well as the cost differences already identified.

In a study of California, McCarthy and Yang (2010) find that marginal GHG emissions of California generation vary substantially by hour of day, with peak hours always having greater emissions than offpeak hours. In their study, emissions from one kWh over the year were 21 percent greater at 5PM than they were at 2AM, and in the summer month of August this difference increased to 36 percent greater. These differences between peak and offpeak may change substantially over the next 15 years as California's renewable generation grows. There may be times, for example, when its growing wind power will be the marginal offpeak generator at near-zero marginal cost. Even in 2011, the U.S. Energy Information Administration reports that CAISO experienced a small number of hours (.1 percent) with *negative* wholesale electricity prices. This phenomenon can be explained by several factors, including hours when wind is the

[35] See the DPUC website section "Mandatory Time-of-Use Electric Rates" at http://www.ctenergyinfo.com/dpuc_rate_design.htm. A phase-in might also be useful in the California context. Connecticut's phase-in has been relatively slow as the necessary meters were not yet in place. California already has the meters and could have a faster phase-in period.

marginal generator and eligible for a 2.2 cents/kWh production tax credit. This means they make more money by generating and paying someone up to 2 cents/kWh to take electricity from them (the negative price) rather than simply not operating. When wind is the marginal offpeak generator, there are neither GHG emissions nor fuel costs and the marginal cost differential between the fossil-fueled peak generator and the offpeak becomes greater. The 2011 Annual Report of the California ISO (2012) attributes the negative prices to strong spring hydroelectric sources combined with wind sources, and it states (p. 73): "…wind is likely to have an increased impact on the potential for negative prices as the amount of wind energy increases even more dramatically in the coming years."

Another study by Zivin, Kotchen and Mansur (2012) using a different methodology, has also reported for the U.S. as a whole and for its major regions dramatic differences by hour in GHG emissions per kWh. Direct comparison with the McCarthy and Yang findings is not possible for several reasons. McCarthy and Yang include several GHGs besides carbon and report results for CO_2e, and their analysis is of California specifically. Zivin, Kotchen and Mansur reported results primarily for CO_2 only, and for the entire WECC region that includes all or part 14 western states (California among them), two Canadian provinces and northern Baja Mexico.[36] Nevertheless, Zivin, Kotchen and Mansur find that in WECC the CO_2 emissions at 12 noon averaged over a year are 33 percent greater than they are at 7AM, and that these differences therefore will be even greater in some months than others. They also find, for some of the non-WECC regions of the country that depend more heavily on coal-fired generation, that the time pattern of emissions can be quite different. For example, they report generally heavier marginal emissions per kWh in the middle of the night compared to the afternoon for the FRCC and SPP regions.[37]

Large methodological differences between the approaches of these two studies suggest it is an important area for further research, in order to increase the reliability of our measures of how GHG emissions from electricity generation vary by time of day and by season. The McCarthy-Yang approach is the more common approach, essentially an engineering-type of analysis in which the hourly demand for electricity is assumed to be met in "merit order:" by those operating plants with the lowest marginal costs, subject to several important constraints like transmission capacities.[38] A potential weakness of

[36] WECC is the Western Electricity Coordinating Council. Zivin, Kotchen and Mansur also report results for sulfur dioxides and nitrous oxides separately in an appendix. The McCarthy-Yang results are for carbon dioxide, nitrous oxides, and methane combined.

[37] FRCC is the Florida Reliability Coordinating Council and SPP is the Southwest Power Pool. The study's results are that night-charged electrically-fuelled vehicles still generally reduce emissions compared to their petroleum-fueled equivalents, but this is not the best time to charge them in these areas. In the WECC area, electrically-fuelled vehicles reduce emissions compared to non-plug-in hybrids at any hour, and more so if charged during offpeak hours.

[38] Their study uses plant-level data from the U.S. EPA's eGRID database, and includes 690 California power plants as well as 505 out-of-state power plants that provide imports from the surrounding regions.

such studies is that the effects of other important institutional constraints, like plant ramping-time constraints and generator commitments made in the ancillary services market, may be missed. Thus the merit order assumed by the study may, to some extent, not be the order followed in actual operation.

The Zivin-Kotchen-Mansur approach is econometric rather than engineering. Based on actual operating data for demand in a system and for all of the generating plants that can be connected to it through the grid, this statistical approach identifies which plants have actually increased or decreased output (and emissions) from one hour to the next in response to the system change in demand for the same period. A potential weakness of such studies is that important data may not be available for the estimations. In this example, the generating plant data was restricted to the fossil-fueled plants, and did not include nuclear, hydroelectric, solar and wind resources that may at times be the marginal generators.[39] The lowest WECC marginal generation cost in this study was $38.25 at 3AM (averaged over the two-year sample period).[40] However, the California ISO routinely reports offpeak wholesale prices in the $10-$20 range that are more definitive estimates of its marginal generation costs, and these prices are too low to be consistent with the assumption that fossil-fueled generators are always marginal.[41] In fact, it states in California ISO (2012) that "Natural gas *and hydro-electric production*…are most often marginal in the system" (p. 33, emphasis added). Another issue apart from data limitations is the electricity market definition: whether or not California is best treated as a price-taking region within WECC, or whether there are enough institutional constraints impeding this so that California is best considered a price-making electricity region of its own, albeit with imports.[42]

There is one final point to make about the importance of California having rates that are commensurate with marginal costs and thus time-varying—what difference will it make to actual behavior? There is a substantial literature on the effects of time-varying electricity prices on demand, and there is a pretty good consensus that short-run demand is highly inelastic: consumers do reduce demand at higher prices, but only on the order of 1 percent for each 10 percent increase in the peak-period price. Nevertheless, retail rates that reflect the marginal cost differences between peak and offpeak periods can lead to strong price differentials, like peak to offpeak price ratios up to 5:1 for simple time-of-use or 10:1 for critical peak periods. Faruqui (2013) reports preliminary results on price responsiveness from a meta-analysis of 33 different studies

[39] McCarthy and Yang (2010) also did not have data on solar or wind, and while they did include both hydroelectric and nuclear generation, they too modeled all marginal generation as fossil-fueled.
[40] See Appendix 3 of Zivin, Kotchen and Mansur (2012).
[41] For example, Figure 3.9 in California ISO (2010) covering the 2009 portion of the sample period reports offpeak wholesale energy costs averaged below $20 for April, May and June, and just at or slightly above $20 for July, August and September.
[42] Zivin-Kotchen-Mansur face the same issue in modelling the other U.S. electricity regions. For the Eastern interconnection, they do not treat the interconnection as one uniform market (as they do for WECC and ERCOT) but allow for variation within the six NERC regions that comprise it.

using 151 different treatments. He finds that a 5:1 price ratio by itself reduced peak load by an average of 12.8 percent, and with enabling technology (like programmable thermostats) the average reduction increased to 22.1 percent. For the 10:1 price ratio the reductions were stronger still: 15.9 percent for price alone, and 29.3 percent with enabling technology. Because the technology to allow automated smart responses of appliances to electricity prices is developing rapidly, it would not be surprising to see further growth in these already substantial effects.

These short-run responses, while important, are only the tip of the long-run responses that should be expected. It is extremely difficult to try and make a quantitative estimate of long-run responsiveness when so much about the world as we know it is likely to be different. Clear time-varying price signals by themselves stimulate technology development to take advantage of them, and while this is likely to be quite significant, no one can predict just how significant. No one knows at this point the extent to which consumers may switch to electrically-fuelled vehicles as their technology and availability continues to improve, and just how slowly or quickly such a diffusion may occur (and how this would be affected by the better price signals).[43] Yet given the critical contribution this electrification would make to GHG reduction in California, it seems essential that we abandon the poor price signals of the past and act to provide the appropriate social marginal cost-based signals for the future. Policymakers should be forward looking in considering how the rate structures they create will affect future decisions.

Some effort has been made to improve electric rates for vehicles specifically, but this effort is both insufficient and somewhat misconceived. The marginal cost of electricity delivered to a residence at a particular time is the same no matter to what use it is put, and there should not be price differentiation between electric vehicle use and any other use. Each of the utilities under CPUC jurisdiction does provide an optional “whole house” rate schedule that can be chosen by households that have these vehicles. Using Southern California Edison as an example, it divides each day into three time periods: a peak from 10AM-6PM on nonholiday weekdays, a “super offpeak” from midnight to 6AM every day, and an offpeak for all other hours. But it continues to use a tiered system. The rates per kWh for customers whose overall consumption is within 130 percent of baseline are approximately \$.33, \$.14, and \$.11 for peak, offpeak, and super offpeak respectively. The rates for customers whose overall consumption is above 130 percent of baseline are roughly double: \$.70, \$.31, and \$.20. These rates are better than the ordinary residential rates, in that the rate for each period is closer to its marginal cost. But the super offpeak rates are still roughly 100 percent above the true marginal costs even for the baseline customers, and 300 percent above for the nonbaseline

[43] There are interesting efforts to do this however. A recent study by Tanaka et al (2013) uses conjoint analysis on a survey of 4000 U.S and 4000 Japanese households to estimate how possible improvements in electric vehicle technology will affect the diffusion rates of these vehicles as a percentage of all new vehicle purchases.

customers. As of 2011, SCE reported only 9428 of its 4,287,994 residential customers (less than one percent) as being on "time-based demand side management programs."[44]

While we are working to improve the carbon and electricity price signals, smart grid technology will also be developing to make consumer responsiveness easier and more automatic. Manufacturers, for example, are beginning to enable appliances like electric water heaters to receive price signals and to "know" to heat when price is low and to stay off unless necessary when price is high. People's attitudes towards activities that cause GHG emissions may also change substantially over time, perhaps in response to new evidence about the effects of them on our climate. The period that may be "peak" for electricity today could evolve into a different period in the future, and the time of the highest marginal GHG emissions will not always coincide with the system peak time. But as long as we have time-varying rates that are based on marginal social costs, consumers will be getting the right signals that will encourage everyone to find the most cost-effective ways to reduce GHG emissions.

In Section III, we identified a legislative constraint involving Tier 1 and Tier 2 rates on California's time-invariant multi-tiered rate system that prevents the CPUC from executing an excellent dividend strategy that provides a clear carbon price signal to all customers and compensates them through the residential accounts. Now we are suggesting further that we must transition away from the time-invariant system to one of marginal-cost based time-varying rates. This may also require legislative assistance in reforming the public utilities code that currently requires use of a tiered rate structure.

[44] The number of SCE residential customers is reported by the U.S. Energy Information Administration in Table 6 of its 2011 data on number of electricity customers found at http://www.eia.gov/electricity/data.cfm#sales. The same page contains links to the survey data gathered about demand side management (DSM) programs, in which utilities are asked how many of its customers are on time-based DSM programs (file 3, column CT). The survey includes time-of-use, critical peak, real-time and other dynamic pricing as time-based DSM programs.

VI. Time-Varying Electricity Rates and Demand Response Programs, Electricity Storage, Distributed Renewable Generation, and Ancillary Services

There are a host of new technologies on the horizon that can, if they come to fruition, make substantial contributions to reducing GHG emissions. Consider, for example, that the CCST (2011) report identifies as a crucial issue the load balancing part of operating an electricity grid. With current technology and policy, substantial fossil-fueled plants are required to provide this balancing. It may be quite possible to substitute demand response and new grid storage technologies for a portion if not all of this load-balancing, especially as the grid smartens. But these will not occur to the extent that they should unless grid prices reflect the proper marginal social value of providing the balance.

Storage batteries offer a potentially very valuable solution to a number of related problems. One is the timing mismatch between renewable generation and systemwide electricity demand: wind power is plentiful at night, and solar power is plentiful when the sun is shining brightly, but without storage they are of little to no use at other times. The California ISO has pointed out a related problem it sees looming as California relies more heavily on renewable generation: there will be increasing times where fossil-fuelled generators must provide very considerable ramping service, as when the system switches rather suddenly as the day ends from heavy reliance on solar to other generation sources.[45] Imagine if the electricity from these renewable sources could easily be stored and then used when they are needed the most; that would certainly increase their value, and would also increase the capability of an electricity system to rely upon these renewable sources. The stored electricity could help with ramping issues. Relatedly, storage batteries would ease the intermittency problem of renewables, when generation falls due to low winds or cloudy skies. Stored electricity from renewables could be a highly reliable source used at any time to provide load-balancing ancillary services.

Given the high value of electricity storage, particularly with growing reliance on renewable generation sources, what factors determine its profitability? The key one is the technology itself: the cost of making the battery so that it may be operated safely and reliably, its capacity and how quickly or slowly it deteriorates over time with usage,

[45] This problem was identified by Mark Rothleder of CAISO in a February 26, 2013 presentation to the "Long Term Resource Adequacy Summit" that included a slide known as the "duck graph" (because the lines on the graph seem to outline a duck shape). The point of the graph is to illustrate that the growth in solar provision expected in California in the next few years leads to unusual ramping problems. One situation is during the late afternoon, typically from around 4PM to 7PM, in which very rapid ramping up of other generation sources will be needed to take the place of the waning solar. The other situation is the morning, when the opposite phenomenon of needing to quickly ramp down the other generation sources as solar begins to pick up the load. Steven Weissman provides a blog that shows the graph and explains the issues: http://legalplanet.wordpress.com/2013/03/25/if-it-quacks-like-a-duck-intermittent-renewables-and-the-grid/.

its speed of charging and recharging, its disposal cost, etc. But for any given state of battery technology, another crucial profitability factor is the price paid for the electricity to charge it and the selling price of the electricity when it is put back into the grid (or equivalently the opportunity cost of using it rather than buying electricity at the time of use). Unless these electricity prices are different, a grid-storage battery can never be profitable. Profitability depends on the size of the price difference between grid electricity when the battery is being charged, and that when it is being discharged. Time-varying rates foster this method of decarbonizing the grid.

At the wholesale level, provided the battery-storage owner has license to buy and sell from the grid as a wholesaler, California has market-based prices that give appropriate signals as to the profitability of the battery. But this is not so for the end-user as a potential supplier of battery storage. For example, if electrically-fueled vehicles become successful and widespread, might not their owners have opportunities to sell some of the vehicle's electricity back into the grid? Might not other appliances owned by the consumer develop to serve as distributed storage batteries? Only if there are time-varying retail rates that make such developments advantageous. We are back to the asymmetry between the time-varying wholesale rates that do approximate marginal costs, and the time-invariant retail rates that do not.

The above paragraph uses the example of electrically-fuelled vehicles, but the same logic applies to entities with solar installations that may have excess electricity during the peak. Net metering rules provide some incentive for these clean grid supply contributions, but under the prevailing rate structures the right signals are not provided. The owner of the solar installation is only offered the flat rate that applies to his or her bill, even though the electricity supplied is typically during the peak period when the wholesale rate is higher, and sometimes much higher than the flat rate compensation. Yet utilities rightly complain that sometimes the net metering compensation is too much, because the retail rates used to calculate it embed fixed costs that are not marginal. However, if the retail rates were time-varying marginal-cost based rates, then the incentives would be aligned: the solar owner would have the right incentive to sell into the grid, and the utility the right incentive for purchasing it. As solar installations continue to increase, we certainly want to be able to take full advantage of the clean electricity that they provide—marginal-cost based time-varying price signals not only encourage this, but they can encourage installations themselves as well as affect their sizes, once owners recognize that they can get fair value for electricity that they do not need for their own use.

One of the more important mechanisms for reducing GHG emissions from electricity is demand response. Sometimes there are situations in which it would be very difficult or very expensive to satisfy aggregate electricity demand by procuring additional generated supply. This happens, for example, during unusually hot days when the existing generators are strained to capacity, and it also can happen when there is some substantial unexpected outage. In these situations, it may be easier and less costly to induce some consumers to reduce their demands than to obtain additional supply.[46] The organizational problem is how to achieve the demand response reliably and quickly. Under prevailing rates, this organizational problem is often solved by utilities themselves or by third-party aggregators. The utility is somewhat motivated to organize these efforts, as the high wholesale price they are paying exceeds the retail rate that they are receiving. It can induce some customers to cut usage with a payment that is in addition to their lower flat rate bills but such that the total compensation (lowered bill plus payment) is still below the wholesale price the utility is avoiding. Sometimes the utility will contract with a third-party aggregator, and then the third-party aggregator signs up the customers who are offered compensation in addition to their reduced bills. The aggregator may have relatively greater knowledge than the utility about how to market and provide such a service.

The most common way to organize the demand response is to sign up the responders in advance, and have the responders agree to give the aggregator some form of electronic control over their air conditioners, water heaters, lighting, or other energy-using appliance. There is usually an agreement that the control can only be exercised for a limited amount of time and only on a limited number of days per year. The control typically does not turn an appliance like an air conditioner off altogether, but it either temporarily alters the thermostat setting, or simply cycles it so it works less hard during the hours of the event (and the temperature may rise several degrees during this time). For lighting demand response (usually in office buildings), some of the lights get automatically dimmed in response to a signal sent by the utility or the aggregator. The beauty of these arrangements is that in many cases the consumers barely notice any difference if at all, and the shortage has been made up with no GHG emissions. Not all demand response programs need work exactly as illustrated above, especially with new smart grid appliance control technologies developing rapidly, but they work primarily by taking advantage of the price difference between high wholesale rates when operating reserves are low, indicating little spare capacity, and the lower rate typically faced by customers.

The problem with this organizational method is that the consumers are not receiving the full incentive to provide demand response, and thus they supply less of it than they would if they faced the right marginal-cost based incentives. Furthermore, the utility does not really have incentive to pursue these programs vigorously, because it cannot keep the profit—it is subject to a profit constraint that is usually unaffected by these programs. Even with simple time-of-use rates that do not get higher on the unusual event days, customers would have substantially more incentive to participate than they do under the time-invariant rates (the savings from the reduced utility bill are greater).

[46] Our focus here is on actual reduced energy usage as the demand response, and not the substitution of a customer's own fossil-fueled back-up generator to replace normal grid electricity. Many demand response programs include both types of resources, but it is only the former that offer substantial potential for reducing GHG emissions.

They would have even better incentives if they were on critical peak or even more dynamic rates. Demand response aggregators would have a much more interested customer base, and could sell their control services directly to the customers who would benefit directly from lower utility bills reduced by the size of the marginal cost savings. These aggregators would focus on their true economic advantages, which are whenever they can arrange for the reductions in a way that is easier and less disruptive for the consumers than doing it themselves.

Marginal-cost based time-varying rates would not only encourage more demand responsiveness during the unusual events described. They open up much broader possibilities for using demand response services on other occasions that may arise with more frequency. For example, we have growing reliance on more intermittent power sources like wind and solar. Thus there may be more occasions where some intermittent sources become unavailable, and demand response resources can briefly maintain the grid balance and buy time to allow good alternate generation to be brought online.[47] Going further, demand response resources may play a much larger role in providing ordinary ancillary services to the grid in general. This type of service has been developing more rapidly in some of the restructured electricity areas of the country. For example, both the PJM and ERCOT areas use demand response to provide spinning reserves.[48] In the large PJM system, demand response resources have provided as much as 16 percent of spinning reserves, with authorization to provide up to 25 percent and PJM may increase that to 35 percent.[49] Yet such routine uses of demand response responses are still the exception rather than the rule. A report by the Federal Energy Regulatory Commission (FERC) lists as a key barrier to the expanded use of these resources the "limited number of customers on time-based rates."[50] Customers need to have the right price incentives to participate.

In sum, marginal-cost based time-varying electricity rates are a key enabling feature to stimulate the growth of a much cleaner future grid. They would stimulate the more rapid development of grid-storage technologies. These in turn can greatly increase the value of generation from intermittent renewable sources, including wind and large-scale solar installations. They also make it much easier to choose the cleanest times for taking electricity from the grid, as with recharging electrically-fuelled vehicles. They increase the value of, and thus encourage distributed solar installations both for individual use

[47] A larger, more integrated grid would also be helpful by reducing the degree of intermittency (it is usually not cloudy and windless everywhere).

[48] PJM is the regional transmission operator for a 14 state region encompassing middle Atlantic and some Midwestern states. ERCOT stands for the Electric Reliability Council of Texas and it operates the grid and manages its electricity markets. Some of the demand response resources in these areas are from customers who have back-up fossil-fueled generators and thus are not necessarily reducing GHG emissions. Still, this illustrates the potential of customers to respond quickly enough to serve as ancillary service resources, and true reduced energy usage demand response can be even faster.

[49] See Katharine Tweed, "Demand Response and Renewables: Too Good to be True?"March 14, 2011 at http://www.greentechmedia.com/articles/read/demand-response-and-renewables-too-good-to-be-true/.

[50] FERC(2011), p. 20.

and for grid supply. They strongly encourage end-users to participate as demand response resources in expanded ways in many circumstances: the unusual event of a supply shortage, as a balancing mechanism for a grid with increased intermittent renewable resources, and for the provision of ancillary services more generally.

VII. Summary and Conclusions

This paper is about one aspect of California's march towards its 2050 greenhouse gas reduction goal of reducing emissions to only 20 percent of its 1990 level. That aspect is the relationship between its pricing policies and the timing and extent of actions undertaken to reduce its GHG emissions, particularly electrifications intended to substitute relatively clean electric power for a fossil-fuel use that would have higher emissions. We focus on the changes needed in pricing policies to enable Californians to make effective and efficient GHG-reducing choices for roughly the coming 15 years. The pricing policies that are in effect now are largely those adopted as part of the state's implementation of AB 32 that mandates a 2020 reduction goal of emissions at the 1990 level, as well as pre-existing policies enacted through the legislature, the CPUC and by California's municipal utilities.

Efficient actions in this context are those that reduce GHG emissions at the least social cost. This is an important policy objective not only because it enables California to do this with the least sacrifice of other important goods and services, but because it must stand as an example that encourages other jurisdictions to join in and make similar reductions. The centerpiece of California's pricing policy for GHG reductions is its cap-and-trade program that establishes a price for GHG emissions throughout the economy and thus incentive to reduce them. The program's designers intend to join at some point with other jurisdictions having similar programs with similar goals. The pending linkage of California's cap-and-trade program with that of Quebec is an opportunity that should be encouraged—it lowers costs, creates new economic opportunities, and will further encourage other jurisdictions to participate.

The allowance prices of the cap-and-trade program provide crucial signals not only to those required to submit allowances (representing 85 percent of allowed emissions by 2020), but to public officials, regulators, and private investors who also will be making decisions that affect GHG emissions. The word "prices" is plural to include not only the current allowance price, which affects short-run emission reduction decisions in the market, but expectations about future allowance prices that affect the long-run emission reduction decisions made through major investments like new electricity plants, industrial plants, and large buildings as well as research and development efforts. There is considerable uncertainty about what these future prices will turn out to be, although it is quite interesting that a major U.S. government review of models estimating the social cost of carbon pegged in 2013 the most likely values of CO_2e for 2050 at $71-98 per ton. An optimal carbon tax in 2050 would be set at the social cost value, and the cap-and-trade equivalent is to issue the number of allowances for 2050 that would make their price equal to the same social cost value. This suggests that, for the near future, it would not be wise to undertake any long-run electrifications that require allowance prices near this range or higher to be cost-effective (e.g. expensive retrofitting of natural gas heating systems in existing buildings). Exceptions to this would be for innovative demonstration projects that may generate substantial learning benefits and thus reduce the cost of future more mature versions of the innovation. Of course estimates of the social cost of carbon are themselves highly uncertain and need to be reviewed periodically in light of new knowledge.

A more pressing issue with California's cap-and-trade program works to discourage one very important set of GHG reductions. As things stand right now, there will be too little long-run investment in GHG reducing actions. This is because the AB 32 legislation that provides the impetus for the cap-and-trade program only mandates specific reductions through the year 2020. While there is an Executive Order of the Governor that mandates California's 2050 goal, such orders can be amended or discarded at any time by any sitting governor. Potential investors in green technology with millions of dollars at stake face unnecessary uncertainty about what permitted emissions levels will be beyond 2020, and this lowers the expected value of the future GHG reductions that their investments would bring. This delays and deters some investments that would be efficient to undertake. ARB should address intended reductions in the 2021-2030 period in its updated Scoping Plan due by the end of 2013, so that the legislature can confirm its intent soon thereafter. Further legislation need not be complex; it could be as simple as confirming a specific interim goal recommended by ARB, like achieving a 25 percent reduction in permitted emissions from the 1990 level by 2030. It should also confirm that the state authorizes and directs ARB, until further notice, to continue beyond 2030 with its programs to reduce GHG emissions gradually and steadily from year to year in order to achieve a sustainable level by 2050 and to maintain it thereafter. Simple actions like these raise the expected price path of allowances between now and 2030, and will encourage important new long-run investments in GHG reducing infrastructure and research and development.

In addition to policies that affect prices in the cap-and-trade program directly, the retail pricing of electricity has very substantial effects on potential electrifications as well as other GHG-reducing actions. While prices in competitive sectors of the economy automatically adjust to the prices of GHG allowances that affect production costs, retail electricity prices are set through regulatory oversight of providers that generally are monopolies within a service territory. In order to make efficient decisions about the usage of electricity, customers must face prices that approximate the marginal social cost of providing the services. To the extent that electrical service requires GHG emissions, the price per kWh of service should include the cost of the GHG allowances used to provide it.

On the other hand, one does not want consumers to bear the burden of higher prices needlessly. ARB decided that the retail electricity distributors should therefore receive free allowances to sell at a state-run competitive auction, and that they be required to use the proceeds for the benefit of their customers. The CPUC oversees this process for the three major investor-owned utilities that serve 80 percent of the state. The legislature directed the CPUC to return these revenues to ratepayers in three groups: industries that are "emissions-intensive and trade-exposed," small businesses, and residential ratepayers. The CPUC understands with great clarity that ratepayers must receive the carbon price signal to give them the intended incentive to reduce GHG emissions. It has devised a generally excellent plan for returning the revenue primarily to residential ratepayers in the form of twice-yearly dividends per residence. They have also provided some revenue as required to the two other groups, but may not have chosen the best strategy for the small business customers. These customers are tentatively being given offsetting volumetric discounts that negate the carbon price signal. They could instead be given twice-yearly dividends that are administered analogously to the residential dividends, and these could even be in amounts based on a small number of historical annual consumption categories (rather than the volumetric amount on the current bill).

The larger problem with the CPUC plan is that existing legislation prevents it from passing the carbon price signal through to the residential customers responsible for almost two-thirds of all residential consumption—those on Tiers 1 and 2 of the multi-tier residential rate structure. This is despite the fact that those same customers would be amply compensated with the twice-yearly dividend. The constraining legislation had its roots in a bill passed in 2001 during the state's electricity crisis that froze the Tier 1 and Tier 2 rates. It was very modestly loosened by SB 695 in 2009, but not by enough to remedy disparate pricing that now causes one customer to pay four times what another (equally wealthy) customer pays for the same kWh of electricity. The same legislation is now preventing the CPUC from giving any GHG price signal at all to the 10 million households in its residential sector—a crucial error in terms of encouraging the GHG emissions reductions necessary to achieve the state's goal at the least social cost. This problem needs a legislative remedy soon, preferably one in which the legislature states clearly the goals it wants the CPUC to achieve, allows the CPUC to use its rate-making expertise to design the best rate system to achieve them, and then holds the CPUC accountable for its performance.

While a large part of the electricity pricing problem is in appropriately incorporating the carbon price signal into rates, another independent part of the pricing problem is that it is difficult to set marginal-cost based rates and also to meet the total revenue constraint that provides a fair rate of return on the utility's investments. Usually marginal-cost rates by themselves raise too little revenue. Numerous ideas have been proposed as ways to solve or ameliorate this general issue. From the standpoint of achieving GHG reductions at the least social cost, the big problem is that current rates for all but the largest customers do not vary with time, whereas the cost of service varies by many multiples as a function of the time of service. This disconnect between current rates and costs prevents many of the most important actions that consumers could and would take to reduce GHG emissions. Thus it seems essential that California transition its electricity customers on to time-varying rate structures that better align rates with marginal costs. One promising idea for accomplishing this and for addressing important fairness concerns is HOOP (Household On and Off Peak) pricing, in which volumetric rates are set at marginal social costs by time and a system of graduated fixed fees is used to cover the small portion of the bill necessary to cover fixed (non-marginal) charges.

One of the most important actions that is being deterred by current policy is vehicle electrification. This is because so many residential customers now face rates in excess of $.30 per kWh at night, whereas the marginal cost of providing night electricity is much closer to $.05 per kWh. Since the most convenient time for recharging electric vehicles is during the night, our current rates are discouraging one of the most promising methods for significantly reducing California GHG emissions.

An issue deserving of further study is just how GHG emissions vary with the time of consumption. Several quite interesting studies have been done of California, and they agree that GHG emissions are higher during peak-period hours, lower in off-peak hours, and that there can be substantial differences in the hourly and seasonal emissions rates depending on the power-generating technology of the marginal generators for each time interval. Thus including these social costs in the marginal cost based rates will increase the size of the cost differences between peak and offpeak periods. However, there are enough methodological and data issues with these pioneering studies that there is still substantial uncertainty about what these marginal emissions are for any particular hour, and how the patterns of them are likely to change in the future as we gradually reconfigure the constellation of generating plants.

There are numerous other efficient GHG-reducing actions that are being deterred by the time-invariant California system, and that would correspondingly be substantially encouraged by marginal-cost based time-varying rates. One of the most important of these is grid storage batteries, particularly those that might be located within a distribution network. In the past, battery technology has not been good enough to make grid storage profitable. However this technology is improving rapidly, and the demand for it on the grid will only increase with future increased reliance on intermittent renewable generation sources like solar and wind power. The value of grid storage batteries depends not only on the technology, but on the differential between the electricity price paid when charging up the battery and the electricity price received at the time the battery is discharged. There is no incentive to store electricity if the price is the same when charging or discharging. But time-varying rates where the peak price can be five times the offpeak price or more provide substantial incentive to develop and use such storage. If the charging electricity has low or no GHG emissions (e.g. wind) and it is discharged to substitute for relatively high emission fossil-fueled electricity, then we are also achieving substantial GHG reductions through grid storage.

Essentially the same logic applies to clean distributed generation technologies like solar power. Current net metering policy for solar is somewhat controversial because the rates used for compensation are often far from actual marginal costs. The end-user is usually on a time-invariant rate, and is often providing electricity during peak-hours when wholesale rates may be substantially higher than the compensation being received. But because the retail rates also embed fixed costs, the compensation is sometimes above the wholesale rate. These situations do not please either the end users or the utilities. However, marginal-cost based time-varying rates would align these incentives, and customers knowing that they will receive fair value are more likely to purchase such installations.

Finally, time-varying electricity rates can help to unlock the vast potential of reducing GHG emissions through increased demand response resources. Under the time-invariant rate system, neither customers nor utilities have strong incentives to participate in these programs. But under marginal-cost based rates, end-users have much more incentive to reduce their consumption when operating reserves are low, indicating little spare capacity. This in turn creates more incentive for the suppliers of appliance-control technologies, those that make consumption-shaving more automatic and less noticeable, to develop and improve them. As the control technologies develop, it expands the range of circumstances under which demand response resources are practical to use. These circumstances include not only the unusual shortage situations caused by very hot days or unexpected outages, but also the more common shortages expected with more reliance on intermittent generation sources like wind and solar, and even the provision of ancillary services. All of these circumstances involve substituting zero-emission resources for what are often high-emission fossil-fuel generators.

This summarizes pricing reforms that are needed to make effective and efficient GHG reductions. For the cap-and-trade program directly, it is important to encourage linkage with other jurisdictions like Quebec. It is also important, for stimulating long-run infrastructure investments and research and development efforts in GHG-reducing methods, to create more certainty in the minds of investors about the permitted emissions levels for the 2021-2030 period, and that there will be continued reductions until a sustainable level is achieved. On the electricity pricing side, it is critical to reform legislation that now prevents 10 million California residences encompassing 80 percent of the state’s population from receiving any carbon price signal. It is possible for the CPUC to improve the signal being given to small businesses. Perhaps most importantly, if California hopes to meet its longer-run goals, it is critical that California transition its electricity customers on to time-varying marginal-cost based rates. If California is to realize its ambitions of being a model that proves substantial GHG reductions can be achieved effectively and efficiently, the reforms discussed in this paper need to be undertaken.

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