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Local Solutions to a Global Problem?**

James Bushnell, Carla Peterman, Catherine Wolfram

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2547 Channing Way  
Berkeley, California 94720-5180  
[www.ucei.org](http://www.ucei.org)

# California's Greenhouse Gas Policies: Local Solutions to a Global Problem?

James Bushnell  
UC Energy Institute

Carla Peterman  
UC Berkeley

Catherine Wolfram  
UC Berkeley and NBER\*

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## Abstract

California is in the process of implementing a broad portfolio of policies and regulations aimed at reducing greenhouse gas emissions. This paper summarizes the initiatives likely to impact the electricity generating sector. We present calculations showing that there is a substantial risk that two of the most prominent policies could simply result in a reshuffling, on paper, of the electricity generating resources within the West that are dedicated to serving California. This reshuffling is different from the conventional leakage problem as it involves no physical changes to the way electricity is generated across regulated and unregulated regions, but is instead driven by a contractual reshuffling of who buys power from whom. The problem is similar to an ineffective consumer boycott. The problem is still present but less severe if more Western states adopt carbon limitations. We also show that some of the least market-based initiatives, the renewable portfolio standards (RPS), are likely to have the biggest near-term impact on the carbon-intensity of electricity generation in the West. Thus the scale of RPS programs may be limiting the potential role of non-renewable options in reducing carbon emissions from the electricity sector.

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\* [bushnell@haas.berkeley.edu](mailto:bushnell@haas.berkeley.edu), [cpeterman@berkeley.edu](mailto:cpeterman@berkeley.edu), [wolfram@haas.berkeley.edu](mailto:wolfram@haas.berkeley.edu). We are grateful to Max Auffhammer, Dallas Burtraw, Alex Farrell, Larry Goulder and Dan Skopec for helpful discussions and comments.

## 1.0 Introduction

When it comes to global climate change, California has been much in the news lately. A series of ambitious policy announcements focused on reducing emissions of greenhouse gases have drawn attention to California's efforts to combat climate change. California assembly bill 32 (AB 32), in many ways the capstone piece of legislation, calls for an overall reduction in greenhouse gas emissions to 1990 levels by 2020. While the details of implementing AB 32 are still being worked out, market mechanisms such as cap-and-trade are being seriously considered. At the same time, several other policies are designed to reduce carbon emissions through more interventionist regulations, aimed, for instance, at altering electricity fuel choice, household energy use, and automotive emissions.

In this paper, we demonstrate how a market-based cap-and-trade policy, when applied only to California, could have very little effect on carbon emissions from the electricity sector. Others have identified the conventional leakage problem, where regulation of one region can cause economic activity to move to the unregulated region (see, e.g., Fowlie 2007). We show that in the electricity industry, California companies could achieve their 1990 emissions levels by contracting to buy power from different sources. Essentially, there is enough existing low-carbon electricity in the west to meet all of California's projected demand in 2020 by simply reshuffling contracts. Unlike with leakage, the reshuffling could be achieved without any change in the carbon output from electricity generation. The problem is analogous to an ineffective consumer boycott. Further, if the electricity sector is allowed to trade with other sectors, it is likely that electric companies could generate excess allowances by reshuffling, limiting the ability of a cap and trade system to reduce emissions in other sectors of the economy.

Real reductions in carbon emissions seem most likely to be achieved by other, more interventionist, command-and-control policies, such as the renewable portfolio standard (RPS), which requires electric utilities to procure a certain fraction of their power from sources powered by renewable fuels. Our results point to the inherent policy questions a small jurisdiction like California must face: Is the goal to truly *reduce* greenhouse gas emissions, and not just cause the sources to change location? Or is the goal to produce a regulatory policy that could be scaled up to a national level, and provide a framework for economically efficient reductions if the policy were more widely adopted? This question is particularly relevant in the setting we consider as the goals are contradictory. In other words, market-based mechanisms appear unlikely to reduce carbon emissions from the electricity sector when applied to California alone. The RPS, while likely to reduce carbon emissions, will only exacerbate the extent to which a cap-and-trade policy can be undermined.

While our paper focuses on California policies and their impacts on the electricity sector, market-based and command-and-control policies coexist in other contexts. It is important to understand how the command-and-control policies are likely to interact with more market-based policies and elaborate on circumstances in which one can undermine the effectiveness of the other. For example, fuel efficiency and low-carbon fuel standards

are designed to reduce the carbon-intensity of transportation, and they would interact with any cap-and-trade initiative that included the transportation sector. Similarly, existing cap-and-trade markets, such as the Acid Rain Program for sulfur dioxide or the NOx Budget Program for nitrous oxides, coexist with New Source Review, a command-and-control program that requires new or substantially retrofitted stationary sources to install pollution control equipment. With conventional pollutants such as sulfur dioxide or nitrous oxides, command-and-control regulations may be valued because they impose an upper-bound on the pollution emitted by any one source. This argument is irrelevant in the case of carbon.

In some sense, the discussions that are unfolding in California represent, on a smaller scale, the same debates on the best ways to formulate international greenhouse gas policies. Just as California must consider both the direct and indirect impacts of its regulations, as well as its ability to influence its neighbors and Federal policy, individual nations must address the same issues on the international stage. The crux of the issue is over the actual goals of such policies: to achieve maximum reductions locally, or to encourage maximum participation outside of the local region?

One such debate has concerned the merits of a “narrow but deep” vs. “shallow but broad” sets of emissions reduction goals (see, *e.g.*, Aldy, Barrett and Stavins, 2003). Some policies focus on an ambitious (*e.g.* deep) set of reductions applied to a small (*e.g.* narrow) set of jurisdictions. The Kyoto Protocol has been characterized as narrow but deep, and California’s goals, which call for deeper reductions in a much smaller jurisdiction must be considered even more so.

One of the criticisms of the narrow but deep strategy is that the ultimate goal, a reduction in global concentrations of greenhouse gasses (GHG), is too easily circumvented. Policies aimed at promoting alternative, “low-carbon” energy sources, will, if successful, also drive down prices of conventional fuel sources, thereby increasing their consumption, at least in areas not participating the efforts.<sup>1</sup> More directly, efforts to curtail emissions from specific industries could result in leakage, as those industries migrate to locations outside of the regulatory regime.

The proponents of the shallow but broad strategy argue that without widespread participation, the leakage issues will overwhelm the best efforts of the participating countries and eventually undermine efforts everywhere. On an international scale, the broad diversity of governance structures and regulatory institutions amongst countries raises additional challenges. It is generally thought that by making the reduction targets more modest, participation will be much more attractive to a much larger set of jurisdictions.

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<sup>1</sup> This argument has been noted in the context of the adoption of bio-fuels to combat US oil dependence, but it is worth noting that the lowering of natural gas prices has also been cited as a benefit of aggressive adoption of renewables (see Wisner, Bolinger and St. Clair 2005).

The direct applicability of such arguments to California's situation depends upon the industry that is the subject of regulation. Transportation services are by definition local, and cannot be exported to other regions, short of an exodus of the people doing the traveling. Industries that produce goods that are costly to transport, such as cement, are also less likely to migrate. The electricity industry, however, represents the opposite extreme.

At first glance, one might expect that the electricity industry may not be much of a migration risk either. Power plants are not easy to move, are quite costly, and experience useful lifetimes over 50 years. However, California has always been a large importer of electricity, and the electricity it does import tends to be among the most carbon intensive. Thus California's regulations do not need to lead to an exodus of power plants in order to be undermined – such an exodus has already occurred. Instead these regulations may simply lead to a re-arrangement of which plants sell power to Californians and which ones sell power elsewhere.

In this paper we focus on 3 overlapping policies that directly impact the electricity sector in California, assembly bill 32 (AB 32) and senate bill 1368 (SB 1368), which limit greenhouse gas emissions, and California's renewable portfolio standard (RPS), articulated in senate bill 1078. The important difference between these policies is that the RPS cannot be achieved with imports from pre-existing sources of renewable power from outside of California, since there was such little pre-existing capacity, while it appears that the goals of AB 32 and SB 1368 can be. In other words, the goals of the RPS are binding even if sources are expanded to the entire western U.S., while the GHG policies are not.

One unfortunate implication of this is that the RPS may be one of the less efficient means of achieving GHG emissions reductions. Unlike a more flexible carbon cap, it does not reward generation from non-renewable sources of low carbon power, and rewards energy conservation only very weakly. Yet the RPS, and other initiatives that are even more narrowly targeted, are likely to be the main drivers amongst these policies at least in the near term.

## **2.0 California Climate Change Policies**

Before describing our analysis of the implications of California's GHG policies, it is useful to categorize them in terms of the generic policy tools that are often employed to combat environmental problems. In general, such policy tools include source-specific emissions limits ("command and control" regulation), preferential treatment, such as subsidies or purchasing requirements, for targeted "clean" technologies, and market-based regulations such as taxes, and emissions credit trading programs. In this section we will briefly explore the attributes of each class of policy tools, and explore their application to GHG policy in California.

## 2.1 Source-Specific Standards

Source-specific standards, or command-and-control regulations, have at times been criticized by economists as an inflexible and inefficient approach to dealing with environmental problems. Under such an approach, a regulatory body determines a standard - such as a maximum limit on the emission of a pollutant or on the energy usage of an appliance – and requires all sources (power plants, appliances, etc.) to individually comply with that standard.

If the standard is enforced broadly, this approach is usually very effective at achieving the environmental goal. The main criticism has been that this environmental success can be much more costly to achieve than necessary. This is because all plants are required to meet the *same* standard.<sup>2</sup> It can often be much less costly for some plants to achieve an even greater reduction in emissions, however, while for other plants any reduction in emissions can be cost prohibitive. In short, source specific standards do not recognize the potential differences in compliance costs amongst the regulated plants and firms, and therefore cannot take advantage of these differences. The severity of this problem is obviously closely related to how significant those potential cost differences really are. Unfortunately, it is often difficult to know exactly how much costs may vary before the regulations are put into place.

Assembly bill 1368 establishes such a standard for “baseload” power plants. The regulation applies to California “load-serving entities” (LSEs), the firms responsible for buying electricity for end-users in California. All power plants from whom these LSEs buy power under long-term contracts, invest in, or build themselves, must meet a standard that limits their emissions to be no greater than a current combined-cycle natural gas plant. In other words energy purchases and investments from California LSEs are supposed to come only from low-carbon power plants.

In the California electricity context, there is another important shortcoming to source-specific standards beyond the classic criticism that they ignore diversity in compliance costs. Another important problem is that the production from specific plants can too easily migrate outside of California’s regulatory jurisdiction. It is important to note that this is usually not a concern when the damage from the pollutant is a local problem, such as urban smog. When a regulation encourages plants that contribute to smog problems to move from the LA basin to a more remote area where smog is not a problem, this can in fact be a beneficial outcome to all involved.<sup>3</sup>

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<sup>2</sup> Regulatory standards aimed at energy consumption, such as appliance standards, and the corporate average fuel economy (CAFÉ) standards for automotive fleets are another important category of command and control standards. For the sake of brevity, we will focus in this paper on supply-side regulations.

<sup>3</sup> This assumes that the new plants do not create severe smog problems in their new locations.

However, when the problem is global climate change, the migration of GHG emitting plants to other states does not help Californians at all. Local concentrations of carbon are not the concern, but rather global concentrations. The earth doesn't care where the carbon comes from, just how much there is.

With this in mind, the important question to consider is the following. Can California LSEs meet their requirements under SB 1368 by shifting their power purchases to low-carbon power plants that have been or would have been built anyway? Does this regulation effect the construction of new power plants at all?

### ***Analysis of SB 1368***

To evaluate the possible impacts of the SB 1368, we assessed whether existing resources provided enough “clean” supply to meet California’s current and expected demand. Our data and specific assumptions are described more fully in the data appendix. At a general level, our analysis involved several steps. First, we defined the market from which California could potentially procure power as the area encompassed by the Western Electric Coordinating Council (WECC). This is the interconnected transmission grid roughly covering the area west of the Rockies. SB1368 implements a maximum CO<sub>2</sub> emissions level based on a Combined Cycle Gas Turbine (CCGT) plant, so we next developed a list of the universe of plants in the WECC whose emissions fell below this level. Existing plants owned by California utilities are not affected by the performance threshold, so these were also included in the list of compliant plants. Since the requirement only applies to plants meeting baseload power needs, we limited the clean set to plants with capacity factors greater than 60%. Finally, we assessed whether output from these “clean” plants, if kept at historical levels, would cover California’s baseload electricity demand.

Figure 1 summarizes the results of this analysis. The bar on the left of the figure depicts the energy output in 2004 from all baseload plants in the WECC by fuel type.<sup>4</sup> The bar on the right reflects the energy output from the subset of plants from which California firms could purchase power under SB 1368. Carbon emissions from coal plants are roughly twice as high as carbon emissions from a gas plant, so none of the coal plants are compliant (save the coal plants owned or contracted for by California utilities which were grandfathered). By contrast, nuclear and hydro output, currently accounting for 233.3TWh of the energy output in the WECC, have no carbon emissions. The emissions standard only applies to energy purchases used to cover baseload demand, defined as purchases from units with a capacity factor greater than 60%. We calculated the demand in California that would have been served by baseload plants in 2004 (i.e., demand in hours where the hourly load level was achieved in at least 60% of the hours) and have indicated this level on figure 1 with the red line. As the figure depicts, California could cover its baseload power needs from clean plants and there would still be 68 TWh of clean supply remaining. Put another way, for every 3 TWh of clean power that

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<sup>4</sup> For purposes of this analysis we defined baseload as operating with at least a 60% capacity factor during 2004.

California would need to contract with, it would have 4 TWh of supply to choose from. Note that our analysis produces a conservative estimate of the remaining clean supply because we have not included plants outside of California from which California utilities are already purchasing power under long-term contracts, although the legislation exempts them until they are renewed.

Several comments give these results context. Recall that SB 1368 exempts plants owned by, or already contracted to, California utilities, so by design the policy will primarily affect from whom California imports power. California imports about one-fifth of its power, but over half of the carbon attributed to California electricity production was from the imports (see Farrell, Kammen and Ling, 2006). The carbon-intensity of the supply in the WECC outside of California is essentially bi-modal, however, with 46% of the supply coming from zero carbon sources like hydro-, nuclear- and wind-powered sources and 35% of the supply coming from carbon-intensive coal sources. Given these features of the Western electricity markets, the standard set by SB 1368 are straightforward to circumvent.

Beyond the surplus of clean power already available in neighboring states, other attributes of the policy could weaken its impact. In particular, purchases made from generation units that run less than 60% are not required to comply with the standard.<sup>5</sup> Also generation bought through short-term purchases, such as the daily wholesale power market, are exempted from the standard. There is a risk that these features will result in more short-term purchases and more generation that runs at 59% capacity factors, rather than cleaner power. In light of these facts, it seems unlikely that SB 1368 will meaningfully affect the carbon-intensity of the power sector in the WECC for the foreseeable future.

SB 1368 may have been designed primarily as a stop-gap measure to prevent significant investment in carbon-intensive generating plants before the overall carbon limitations associated with AB 32 are phased in. Unfortunately, since California is but one buyer from the Western electricity markets, coal plants can be built as long as the power is sold to customers outside of California. For example, Sierra Pacific Resources, a Nevada utility is proceeding with plans to build a 1,500MW coal plant called the Ely Energy Center. Reacting to SB 1368, the Sierra Pacific Resources spokesperson said, “The Ely center is needed here in Nevada just to keep up with the enormous growth that we are experiencing.... The Ely center will generate energy for the state of Nevada,” (see California Energy Markets, 2007, p.12). Further expansion of coal capacity in states like Nevada could free up low-carbon sources currently consumed in these states for sale into California. Note that since electrons follow the laws of physics and not the directives of financial contracts, Californians will still be consuming some of the power from coal

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<sup>5</sup>The exemption is in place because the best technologies for meeting peak demand are natural gas fired combustion turbines. These technologies are relatively low capital cost, but have fuel efficiency and emission profiles worse than the combined cycle gas plants upon which the standard is based. It would be impractical to operate natural gas plants to “follow load” as the more nimble, combustion turbines are designed to do.



plants like the Ely Energy Center, even if SB 1368 forbids California utilities from contracting with them.

## ***2.2 Promoting “Clean” Technologies***

In the policy arena, one popular alternative to limiting the use of “dirty” technologies through regulatory standards is the promotion of alternative, “clean” technologies. The promotion of such technologies can be accomplished through direct subsidies for the manufacture or installation of the technologies, through tax incentives, or through mandates that certain institutions buy a certain percentage of their consumption from “clean” sources. The political appeal of such an approach is obvious: instead of appearing to raise the cost of conventional energy sources, these tools appear to lower the cost of the alternatives.

Proponents of these policies often point to a variant of the “infant industries” argument. This hypothesis, often applied in the context of international trade, argues that certain technologies or industries can be very competitive with incumbent technologies if they could capture the necessary economies of scale or learning. The subsidies promoting these technologies thus speed up the development, moving the industry along the learning curve faster, or allowing it to grow to a minimum efficient scale quicker. Once these technologies reap the benefits of such efficiencies, no further intervention is necessary. These new alternatives will, in theory, be preferred even if the environmental costs of the old technologies are not borne by the producers.

There are several criticisms of such policies. First, although it is perhaps politically appealing to make “clean” technologies look cheaper, rather than make “dirty” sources seem more expensive, such an approach sends the wrong message to consumers. There are no additional costs associated with continued consumption from dirty sources. The opportunity for encouraging conservation in the obvious way, by making the production more expensive, is therefore lost. In practice, the cost of the subsidies are often borne by other customers, so at least indirectly dirty consumption is made more expensive.

A second, related criticism of “green” subsidies is that, by drawing demand away from fossil fuel sources, they will indirectly reduce the prices of fossil fuels. From a consumer perspective this can sound appealing, but from the perspective of an environmental regulator, lower prices for dirty fuels are counter-productive. Even if consumption from fossil fuels is discouraged within the region where the subsidies are applied, lower prices will encourage consumption elsewhere. This contributes to the problem of emissions migrating to other regions.

Perhaps the most poignant criticism of targeted subsidies is that they rely upon a very wise and benevolent process for them to be implemented efficiently. Even with very intelligent and dedicated regulators, the information requirements to pick the “right” technologies are daunting. The risk of large subsidies going to technologies that would not prove competitive under ideal regulations is very high. Politicians and regulators are in effect placing large bets that the promised economies of scale and learning will in fact

materialize. If these benefits do not appear, there are often calls for continued subsidies. There are many cases of “infant” industries that have never grown up.

There is no question that politics also plays an important role in the subsidies game. Few would deny that the U.S. focus on corn-based ethanol is heavily influenced by the politics of the Midwestern farm-belt. Federal tax incentives provided for the purchase of hybrid-fuel cars were deliberately designed to favor producers who sell hybrids in smaller volumes. These producers also happened to be the US auto manufacturers. Of course this criticism could be leveled at just about any regulation, or public policy for that matter. Because they often involve direct transfers of money to some parties, subsidies appear to be even more vulnerable to these pressures than other regulations.

Despite all the potential faults of direct, targeted subsidies, they do feature one distinct advantage over the other policies discussed here: they are less vulnerable to leakage or other means to bypass emissions regulations. They can therefore be more appealing to smaller jurisdictions, such as US states, than other regulatory tools that can be more easily bypassed. While such policies may not be an appealing choice on a national or international scale, they may be the only means to meaningfully impact emissions on a more local level.

### ***California Alternative Energy Policies***

Although California has a wide variety of initiatives targeted at specific technologies, we will focus our discussion on two of the most prominent programs: the California Solar Initiative and the renewable portfolio standard (RPS). The two policies are very different their approaches, but share the general feature that they focus on the *inputs* into the production of electricity, rather than the *output* of greenhouse gasses.

The California Solar Initiative is a set of direct subsidies for property owners who install solar photovoltaic systems on their buildings.<sup>6</sup> Over the next ten years, the program allocates up to \$2.8 billion, drawn from general electric rates, for these subsidies. The program represents a classic example of a targeted subsidy. Its proponents claim that an expansion of solar photovoltaics in California will spur new efficiencies in the design, production, and installation of solar PVs and spur local economic investment in the industry. However, these benefits are far from guaranteed.

As critics of the program have pointed out, an injection of even several hundred million dollars per year into the worldwide solar PV market, estimated at over \$5 billion, while significant, would hardly constitute the dramatic, transformational, change in demand necessary to capture needed efficiencies. A program of this scale would likely ramp up production capacity of the *existing* technology, rather than spur needed innovation in *new*

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<sup>6</sup> The original form was adopted by the California Public Utilities Commission, and 2006 Senate Bill 1 extended the program to most municipal utilities. Interestingly the largest California municipal utility, LADWP is in effect exempted from these policies.

technologies.<sup>7</sup> At current costs, current generation Solar PV represents a curious technology to place a bet on. Even generous estimates indicate that solar PV installations cost about 25 cents/kwh, many multiples of the current costs of coal, natural-gas, or even wind powered electricity generation.<sup>8</sup> If the hoped for efficiency benefits of these subsidies do not materialize, the MWh procured under this program could be 4 to 5 times more costly than other alternatives.

The RPS, by contrast does not target a specific technology, but rather a class of technologies, for preferential treatment. Under its latest manifestation, Senate Bill 1078, the RPS requires all LSEs in California to procure at least 20% of their electrical energy from renewable sources by 2010.<sup>9</sup> The advantage over a targeted subsidy is that these various renewable technologies compete against each other. In theory, the “best” (or lowest cost) choices amongst renewable options will come to dominate the portfolios of firms. Thus, for example, if solar PV continues to be one of the most expensive renewable options, LSEs are free to invest in other more economic choices. In this way, the RPS shares features of more market-based approaches to regulation.

Although the RPS, at least at first glance, is a more flexible approach to dealing with GHG emissions than targeted subsidies, it also has its limitations. Because of its focus on the fuel inputs, rather than carbon output, firms do not benefit from alternative solutions to the emissions challenge, such as energy-efficiency, carbon sequestration, or nuclear power. Many observers believe that significant investment in some or all of these non-renewable alternatives will be necessary to achieve long-term GHG reductions goals. Further, although there are aspects of inter-resource competition in the RPS, the playing field may not be completely level. For example, when accounting for the costs of various renewable technologies, it is not clear how the costs of new transmission, which will likely reach many billions of dollars, will be treated. The transmission problem has also been exacerbated by the focus on getting the renewable power “into” California. From a climate policy perspective, wind power is just as useful if it displaces coal generation in Canada, than if it is “imported” into California. Current policies do not allow for this kind of substitution to apply to the portfolio obligations of California LSEs. Last, some renewable sources such as biomass, may have questionable GHG benefits.

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<sup>7</sup> See Borenstein (2004).

<sup>8</sup> At the residential level, these costs are further subsidized by the practice of “net-metering.” Generation from residential power sources can be used to offset not just the cost of utility electricity generation, but also the sunk costs of the network infrastructure such as transmission wires and other utility operations. This practice has been workable on a small scale, but may become unwieldy if extended to a large number of residences. The problem is that the other, non-solar residences have to pay relatively more for these infrastructure costs since they are spread over a smaller number of customers, in addition to funding the direct subsidies for the solar installation.

<sup>9</sup> For purposes of the RPS, “renewable” electricity is defined as energy generated from conventional renewable sources such as solar thermal, solar PV, wind, geothermal, biomass and hydro. Large hydro projects (greater than 30MW) are not considered renewable.

Like the targeted subsidies approach, however, the RPS has been and will continue to be a strongly binding regulation that is dramatically changing the procurement practices of electric utilities. This is because the amount of renewable capacity necessary to meet California's RPS obligations does not yet exist in California or anywhere else in the western US. Because little renewable capacity exists outside of California (see table 1), the option to export dirty power and import the renewable energy of other states does not exist.

At the same time, many other states have also adopted their RPS policies (see table 1). The details vary by region, but share an important common feature. There is not sufficient pre-existing renewable capacity to satisfy these requirements. This means that these policies, if enforced, will be binding.

### **2.3 Market-Based Environmental Regulations**

We next consider market-based approaches, which could include taxes on carbon emissions or programs through which the government limits carbon emissions by issuing permits that can be traded among polluters (so-called "cap-and-trade" policies). Rather than dictating the specific technology, or fuel choice, to be used in reducing emissions, these programs use price signals to provide incentives to firms to reduce emissions in the most cost-effective way possible.

Because of their inherent flexibility, these policies are attractive in circumstances in which they can be practically applied. They do not require a perfectly-informed regulator to come up with the optimal carbon-reducing strategy. Individual firms will in theory arrive at their least-cost method for reducing emissions because, under most circumstances, they have an incentive to do so.<sup>10</sup> Regulators still play a central role in a market-based system – the parameters of the regulatory instruments will drive firms' decisions – but their role is more constrained than under other regulatory approaches.

An emissions tax places an explicit charge on each unit of pollution produced by a firm, or individual. If a firm has options for reducing its emissions that are less expensive than the tax itself, it should adopt those options and reduce its emissions. Importantly, one of the options likely to be considered is simply consuming less of the input that is producing the pollution (*e.g.* fuel, fertilizer, chemicals). Thus taxes, in a relatively straightforward fashion can directly, and appropriately, impact both production and consumption choices in a market. The tax revenues can be applied to efforts to further reduce emissions or used to offset other taxes. In practice it is often the case that taxes are not directly applied to the pollutant, but rather indirectly at sources contributing to pollution, such as gasoline. These taxes may not have been imposed for the sake of environmental

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<sup>10</sup> There are many cases where a firm's incentives may not be aligned strictly with minimizing its compliance costs. For example, a regulated firm may prefer options that can be added to its rate base (see Fowle 2006).

regulation, but do impact the behavior of firms and individuals, and therefore the environment, nonetheless.

There are two facets of emissions taxes that contribute to their perception as the intellectual playthings of ivory-tower economists, rather than practical tools for policymakers. First, they are viewed as extremely unpopular and therefore politically infeasible. Taxes in general are a hard sell, although “sin” taxes (applied to socially unappealing activities such as smoking and consuming alcohol) have often been the first recourse for policymakers that have been forced to raise revenue. It is important to stress also that these taxes need not even increase government revenues, but could be used to offset other taxes. However, critics point out that such a revenue neutral approach to new taxes would be rather novel in the history of government.

The second important concern with emissions taxes is that they do not guarantee that emissions will in fact be reduced. If consumers and firms decide that paying the tax is less costly, or more convenient, than reducing pollution, then the tax will raise revenues without actually changing behavior. More realistically, taxes may change behavior somewhat, but figuring out exactly how much is a complicated forecasting exercise. Environmental regulations are usually developed with a target (ambient concentrations, source specific emission rates) in mind. Once that target is developed, regulators usually feel more comfortable implementing measures that they are confident will reach that target.<sup>11</sup>

Fortunately, even the regulation of emissions quantities can be achieved in a market-based fashion. The cap-and-trade approach to emissions regulation is an example of a market-based regulation of quantities. A cap-and-trade system applies an overall regional limit to total emissions (the cap) and allows for flexibility as to who within that region actually emits. Emissions credits, totaling no more than the regional cap, are created and allocated to the regulated firms. In theory, firms that can cheaply reduce their emissions will sell credits to firms that find it very expensive to reduce (the trade). The net result is that the emissions target is achieved in a way that minimizes overall costs.

The concept of emissions credit trading has had a colorful history in the United States. Originally the concept was derided as the moral equivalent to selling “indulgences” for sins. The application of a cap and trade system for SO<sub>2</sub>, developed under the 1990 amendments to the Clean Air Act, has been widely viewed as successful (see, e.g., Stavins 1998). Since that time, emissions trading systems have become increasingly

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<sup>11</sup> There is a rich literature in environmental economics, dating back to Weitzman (1974) on the proper use of “price” tools such as emissions taxes vs. “quantity” tools such as command and control regulations or emissions caps. The general idea is that taxes help to limit uncertainty over the costs of compliance while quantity regulations help to limit the uncertainty over how much pollution results. The choice is rarely strictly between one or the other. For example, an emissions limit is usually accompanied by a penalty for violating that limit. This penalty could be thought of as a tax on emissions above those imposed by the regulatory limit.

appealing to policymakers. One important practical advantage to these systems is that the regulatory burden can be smoothed through the allocation of the credits. These allocations can be used to mitigate, or even co-opt, the opposition of firms who might be the most vulnerable to regulations of any kind.

It is important to recognize that cap and trade systems are not universally appropriate, or immune to criticism in practice. While the SO<sub>2</sub> program has been viewed as a success, programs to trade certain smog-producing pollutants (NO<sub>x</sub>) in southern California and the eastern United States have run into a variety of problems.

For many pollutants, a key problem is coming up with a workable definition of the region over which the cap is to be applied. It is important to try to match the region being regulated to the region being impacted by the emissions. One shortcoming of most cap and trade systems is that they focus solely on *how much* pollution is being created and ignore the importance of *where* the pollution is coming from. For a more localized pollution problem, such as smog, this means that the capped region would ideally be relatively small. If the capped region is defined too broadly, there is a risk that emissions reductions will occur in regions where the pollution does little harm, rather than where such reductions would have the most benefit. Thus the RECLAIM emissions credit program in southern California covered the LA basin but not the San Francisco Bay Area. Reductions in NO<sub>x</sub> in the Bay Area would have no benefit on smog conditions in LA.

Indeed, even the SO<sub>2</sub> program has been criticized for ignoring the geographic importance of emissions.<sup>12</sup> Regulators took the opposite of the RECLAIM approach to NO<sub>x</sub> trading in the eastern US, where NO<sub>x</sub> credits can be swapped amongst firms in nineteen states. Recent research has demonstrated that the bulk of the reductions in NO<sub>x</sub> emissions have been concentrated in southern states, even though most of health problems arise from emissions in the Midwest and Northeast (see Fowlie 2006).

Although the nature of the pollutant may argue for a small trading region, small regions can lead to other problems. A small region will feature fewer firms that are subject to the regulation, and therefore less liquidity in emissions trades. Further a small region is more likely to be dominated by one or two large polluters who may enjoy market power either in the product they produce or in the pollution credits themselves. It appears that the RECLAIM program was plagued by both of these problems (see, e.g., Kolstad and Wolak, 2003).

A related problem arises when the definition of a region is too small to capture all of the relevant sources of pollution. This is the problem of *leakage*, where firms “reduce” their pollution in the regulated region simply by moving their facilities to an unregulated region. In the case of a localized pollutant such as NO<sub>x</sub>, this may not be a problem. It is likely efficient for smog-producing facilities to leave the LA basin for other areas where

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<sup>12</sup>States in the northeast have complained that under the SO<sub>2</sub> trading program, there has been relatively little reduction in SO<sub>2</sub> emissions in states upwind of the eastern seaboard, which has borne the greatest impact of SO<sub>2</sub> emissions.

smog is a distant concern. In the case of GHG emissions, leakage is a major difficulty. From a climate change perspective, California is equally vulnerable to GHG emissions in Nevada (or China) as it is to GHG emissions within its own borders.

One policy that could combat leakage is to focus regulation on a “consumption” standard rather than a “producer” standard. This means that, for purposes of tracking emissions, a firm is responsible for the emissions created by the plants it takes delivery of products from, no matter where those plants may be located. For example, an electricity firm in California that takes delivery of power generated by a plant in Utah will still be treated as “producing” the carbon from that plant in Utah. Similarly, firms burning ethanol in California would be responsible for the GHG emissions used in producing that ethanol, even if it was produced was in Iowa. Such an approach requires potentially much more sophisticated monitoring of emissions activities, as the regulator is trying to track emissions all the way up the supply chain and far beyond its normal regulatory jurisdiction. There are also questions about the legality of such an approach for individual states.<sup>13</sup> Assuming such tracking can be achieved, and the legal obstacles overcome, this approach can go a long way to preventing the perverse effects of leakage *under the right circumstances*.

Under some circumstances, however, a consumer-based standard to cap-and-trade can fall victim to a comparable problem, the *reshuffling* of production. This is a problem, like leakage, that can arise when the area being regulated is much smaller than the area from which troublesome pollution can be produced. Although the regulator can force its local firms to buy “clean” products, it can’t keep firms in other states from buying the “dirty” products that the firms in the regulated states used to buy. If there is already substantial clean production capacity in neighboring regions, the regulation can result in the local firms simply swapping suppliers with their brethren in other states. For example, there is both clean (low-carbon) and dirty (high-carbon) ethanol produced in the US today. If California requires its firms to buy clean ethanol, then firms in other states will buy the dirty ethanol forsaken by Californians. There would only be a net change in clean ethanol production if the amount of clean production *everywhere* is less than the requirements of California customers.

The problem is similar to the conditions that limit the effectiveness of consumer boycotts. Although a percentage of motivated customers stop buying from the boycotted source (*e.g.* diamonds thought to support “blood” regimes), there will be no net impact on sales or prices if there are enough other price-sensitive customers who are indifferent to the cause of the boycott and willing to shift over to the boycotted producers. As soon as prices from the boycotted sources fall because of the boycott, other customers shift over and prices rise again.

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<sup>13</sup> For example, some states have claimed that California’s attempt to regulate the purchases of firms within its borders of products produced outside its borders violates the commerce clause of the constitution (see, *e.g.*, Potts, 2006).

As we describe below, the leakage and reshuffling problems are of more than academic concern when it comes to California's GHG policies. If California acts unilaterally, without the participation of other western states, these problems are likely to overwhelm any meaningful impact of the regulations.

### ***Description and analysis of AB 32***

The California policies most relevant to the discussion of market-based regulations are those that could emanate from the process initiated by California Assembly Bill 32 (AB 32). The bill itself does not establish specific policies, but rather articulates an overall goal of reducing California's GHG emissions to 1990 levels by 2020. Unlike the RPS and SB 1368, the scope of AB 32 extends well beyond the electricity industry to include most major sources of GHG emissions. The exact methods for achieving the goals articulated in the bill are to be determined by a process that is currently ongoing. Market-based regulatory tools, such as a cap-and-trade program, have been widely discussed but are also somewhat controversial.

Since a framework of a cap-and-trade system for CO<sub>2</sub>, or perhaps all GHG, is being seriously considered, it is important to examine the likely implications of such a system when applied to California. Because no detailed program has yet emerged, we must make some assumptions about the exact nature of the program.

We will focus only on the electricity industry. This is in part because we are interested in the question of how a cap-and-trade system compares with other policies that are targeted exclusively at the electricity industry. It is very possible that such a program would include other industries, particularly other large stationary sources of emissions such as refineries and cement plants. However, CO<sub>2</sub> emissions from electricity are considerably greater than those other stationary sources, and many expect electricity to bear a disproportionate responsibility for reducing carbon emissions. Further we will limit our analysis to the 2020 goal of reaching 1990 levels, rather than the far more ambitious goals for 2050.

We consider a policy aimed at reducing California's GHG emissions attributable to electricity consumption to 1990 levels. As described above, there are two possible approaches to measuring the amount of emissions from California's electricity industry: a *producer-based* measure and a demand or *load-based* measure. A producer-based measure would regulate GHG gasses emitted only from plants physically located within California. This is an especially problematic approach in this context, since a substantial fraction of California's electricity and a majority of the GHG emissions, come from plants outside of California.<sup>14</sup> There is a significant risk that a producer-based standard

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<sup>14</sup> The accounting of production is complicated somewhat by the fact that there is coal capacity owned by (or contracted to) California LSEs that is located outside of California but connected in such a way that, electrically, it is treated as within California. The CEC attributes over 28 TWh of electricity generation to plants that fall in this category.



could be easily circumvented by simply increasing net imports from outside of California. These imports count as perfectly “clean” under a producer-based standard.

For this reason, we focus on a consumer-based standard for California. While this approach may seem more likely to constrain firms, even a consumer-based standard is vulnerable to a reshuffling of transactions. LSEs inside California can reduce their purchases from dirty plants and increase their purchases from existing clean ones, and firms outside of California could do the reverse.

To assess the plausibility of such an outcome, we again examine the mix of generation available in the western electricity market. Table 2 shows the amount of energy produced in 2004 from each major fuel source in each sub-region of the western market. As is evident from this table, the amount of energy from zero-carbon sources, hydro and nuclear, is substantial. Also note that California has a relatively clean fuel mix (at least with regards to CO<sub>2</sub>), with large amounts of nuclear and hydro production and comparatively little coal production. To examine whether there is enough low-carbon capacity to meet California’s AB 32 goals for electricity, we use a projection of California’s 2020 electricity demand of about 341 TWh.<sup>15</sup> The CO<sub>2</sub> emissions created to serve California demand in 1990 was approximately 82.0 million metric tons (MMT).

Figure 2 plots the cumulative CO<sub>2</sub> emissions from power plants in the west in 2004 against the cumulative TWh of electricity produced by these plants, where the TWh are assumed to come from the lowest carbon sources first. For example, the function is equal to zero for the first 264 TWh of output because zero carbon sources produced 264 TWh of output in 2004. The horizontal line in figure 2 is drawn at the emissions level that California would need to achieve to meet the AB 32 standard (the 1990 level of 82.0 MMT) and the vertical line is drawn at the projected 2020 demand (341 TWh). The function crosses the vertical line before it crosses the horizontal line, suggesting that California could procure power in the western markets from existing sources without exceeding 1990 carbon emissions levels. This implies that even a load-based standard for California is at serious risk of circumvention through a swapping of energy sources amongst the western states.

Our analysis reflects many important underlying assumptions about the willingness and ability of western electricity firms to trade their electricity. It is intended as an illustrative calculation to indicate the potential severity of the problem, rather than a forecast of what is likely to happen. That said, we can consider several of the most likely impediments to a complete reshuffling of energy sources in a relatively straightforward way, and they do not change the overall conclusion that California is not a large enough player in the western electricity market to cause substantive change with a cap-and-trade policy.

First, we consider the fact that the ability to import power is limited by the transmission network. These constraints stem from limits on the aggregate capacity on important

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<sup>15</sup> This number is comparable to the CEC’s forecast of 340 TWh. For details see the appendix.

transmission interfaces between California and other states and the need for a non-trivial amount of generation to be operating near load-centers for voltage support and other reliability considerations. A rough approximation of these “local” needs would be to take California’s 2004 generation, and assume it continues unchanged. In other words we limit the ability of firms to “swap” power generated within California for power generated outside of California. As figure 3 demonstrates, this adjustment does little to change the overall conclusion. Since it is California’s current imports that are its high-carbon sources, a rearrangement of the power that is imported into California is sufficient to meet the AB 32 target.<sup>16</sup>

A second observation is that institutional and contractual arrangements may limit the willingness or ability of some firms to sell their “clean” power to California. For example, much of the power generated by Federal water projects and marketed by the Bonneville Power Administration (BPA) is allocated according to a Byzantine set of procedures that do not closely resemble market activity. The firms that *buy* power from BPA are not necessarily operating under the same limitations, and may be able to resell that power. However, it is worthwhile to examine just how much reshuffling has to occur in order to effectively undermine the targets of AB 32. Even if we assume that California cannot buy any energy produced by BPA (even though it does purchase some today) and must use its in-state generation (as we assumed above), it can stay just inside the 1990 emissions levels at 2020 demand by importing power from clean suppliers other than BPA.

It is also important to recognize several important factors that we have left out of our analysis that would make it *more* likely that AB 32 would not significantly impact the electricity industry in 2020. We are not including Canadian electricity generation, even though there is currently substantial power traded between California and British Columbia. We have also not accounted for the additional zero-carbon capacity that is almost certain to be added as a consequence of the various RPS in western states. California’s RPS alone implies that an additional 39.7 TWh of low carbon energy will be added to its system. Finally, we have assumed that plants will generate the same output in 2020 as they did in 2004. Older plants tend to be run less intensively, so if the supply that is added between now and 2020 is cleaner than the output it is replacing, the standards will be easier to meet.

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<sup>16</sup> Note that a reshuffling of imported power amongst “importing” states need not cause any additional transmission congestion. Although there are strict physical limits on how much hydro power flows south from the Pacific Northwest, these flows can be offset by flows of coal production from the Southwest up to the Northwest. If, for example, northwestern or Canadian utilities simply “swapped” the energy from their own hydro production with energy from LADWP’s Intermountain coal plant, there would be a change of carbon accounting on paper, but no net change in the actual flows of electricity. Of course these utilities would likely receive some extra payments from California utilities for engaging in the transaction.

The reshuffling in the electricity sector could impact the effectiveness of AB 32 in other sectors. If the cap-and-trade system allows trading across sectors, than electric companies could sell any excess allowances they create by reshuffling. Firms in other sectors could purchase the allowances created by reshuffling instead of actually reducing the carbon emissions from their production processes. This would limit the ability of a cap and trade system to reduce emissions in other sectors of the economy.

This analysis implies that a load-based cap-and-trade system is highly vulnerable to a reshuffling of energy sources if it is applied only to California. It is possible that additional regulatory restrictions could limit this effect. For example, regulators could require that California imports be purchased from *new* sources. Such a limitation could seriously undermine the market-based attributes that formed the advantages of a cap-and-trade system in the first place, however. Another approach to limiting reshuffling is to credit emissions from imports at a regional average rather than according to the emissions of the specific source from which it is purchased. While limiting reshuffling, firms outside of California would have no incentive to invest in new capacity with low carbon emissions or to retire existing capacity that is particularly carbon intensive since the carbon emissions of a single plant would be small relative the market.

#### ***A five state cap-and-trade program***

A better outcome for the fate of a cap-and-trade program would be the expansion of its jurisdiction beyond California. At the end of February 2007, California Governor Schwarzenegger together with the Governors from Arizona, New Mexico, Oregon and Washington, announced a plan to do just that. The Governors outlined plans to establish a regional cap within six months and to set up a regional cap-and-trade system within 18 months (see Eilperin, 2007). In view of this announcement, we expand our analysis to include the five states party to the agreement.

Very few details have emerged about what a five state cap-and-trade program might involve, and data limitations force us to make more assumptions about the trade between these regions. In particular, we will be forced to assume that, for the most part, trading in electricity from one of these states is limited to transactions with one of the other five states. In other words, all historic electricity trades are considered to be within this five state block. This would have been a bad assumption for California, which imports 22% of its power, but when we expand to the five-state region, total generation within the states (477 TWh in 2004) is if anything slightly larger than total demand (464 TWh in 2004).

We first examine the prospects for a producer-based standard encompassing all five of these states. According to the Energy Information Administration, total CO<sub>2</sub> emissions from all electricity producing sources within these five states were 125 MMT in 1990. CO<sub>2</sub> emissions had grown to 167 MMT by 2004 (an increase of 34%). As table 3 demonstrates, carbon growth between 1990 and 2004 varied considerably state to state. States in the Pacific Northwest showed the highest proportional increases as a high fraction of their capacity installed by 1990 was hydro or nuclear plants, which are zero

carbon sources. In terms of raw tonnage of carbon emissions, however, Arizona stands out as the state with the largest increase since 1990 (and therefore the farthest away from a target of reducing to 1990 levels). Arizona generation accounts for roughly half of the 42 MMT increase in the five states since 1990.

An important difference between a cap-and-trade program directed at these five states and one directed at California alone is that a reshuffling of imports is not as easily accomplished. Because of growth in carbon production in these states over the last fifteen or so years, achieving 1990 levels will require more changes (either financial or real). Total load for the five states is projected to be between 588 and 636 TWh in 2020.<sup>17</sup> In order for the five states to meet 2020 demand using only as much carbon as they did in 1990, they must displace some existing carbon intensive generation as well as acquire more energy to meet load growth. Under the producer-based standard this new supply could either come from clean (say zero-carbon) generation from within the five states or imports of energy *of any kind* from outside the five states.

We examined different scenarios for reducing carbon production from within the five states by the 43 MMT of carbon necessary to reach 1990 levels. Assuming that the most carbon intensive plants are closed first, this would amount to retirements of 7,248MWs of capacity (roughly equivalent to 3 Navajo coal plants), 71% of it coal-fired. Thus a producer based-standard would likely help to induce (or reinforce) a decision to retire a few coal plants by 2020. The key question though, is what kind of capacity would replace the production of those plants, and also generate the additional energy required to meet load growth in this region? The problem again with a producer-based standard is that this additional production could be met from new facilities located outside of the five-state block. If the new plants are coal-fired, little overall benefit to the GHG problem is achieved.

Given these facts, we turn our attention to a load-based standard applied to the same five states. This regulation would apply to generation located anywhere as long as it sold energy into the five state block. Adoption of a load-based standard actually relaxes the carbon target somewhat, as California's imported coal production would count toward setting the 1990 level standard. When one adds this "imported" carbon, 1990 emissions amount to about 142 MMT, as opposed to 125 under a producer-based standard, and 2004 emissions were about 11 MMT higher at 178 MMT.<sup>18</sup> Thus, following our earlier

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<sup>17</sup> The forecast of 636 TWh assumes that annual load-growth in the five states follows the 10 year WECC average of 1.98% between 2004 and 2020, the forecast of 588 TWh assumes growth of 1.5%. Since growth in some of these states has been below that level recently, there is reason to believe this estimate could be high, and therefore conservative for the purposes of examining the impact of a GHG initiative.

<sup>18</sup> A large coal plant owned by a California utility but located in Nevada (*i.e.* outside of the five-state block) closed between 1990 and 2004, so the difference between the producer and the load-based standard is larger in 1990 (17 MMT) than in 2004 (11 MMT).

assumptions, the five states would need to acquire an additional 120-170 TWh of energy, while at the same time *reducing* carbon consumption by 36 MMT to 1990 levels.

One way to achieve this goal would be to assume that all new load growth will be met from zero-carbon sources, as will the additional TWh needed to achieve the 36 MMT reduction necessary to reach 1990 levels. The retirement of three large coal plants, (*e.g.* Navajo, Cholla, and Springerville in Arizona) would displace over 32 MMT of carbon while creating a need for an additional 30.2 TWh of energy. Under this “all zero-carbon” scenario, a total of about 150-200 TWh of new, zero-carbon energy would be required.

We must now consider two further relevant facts in this analysis: the addition of 65-75 new TWh of renewable energy under the various RPS in these five states, and the presence of roughly 70 TWh of hydro energy in neighboring regions of the WECC, including Canada. The combined 135-145 TWh of zero-carbon energy sources would be nearly sufficient to meet the emissions standard at the lower end of our load-growth projections, and the standard could be met if there is sufficient new zero-carbon generation added outside the five states. If we assume that all the zero-carbon energy is available for sale into the five-state region, again recognizing that a paper reshuffling of generation sources would not alter regional electricity flows and therefore transmission constraints, then the combination of the RPS and additional reshuffling could limit the impact of a load-based cap-and-trade policy even if it were extended to these five states.

There are several reasons to believe that not all of this additional hydro energy would be available for this reshuffling exercise. Since Canada is a signatory to the Kyoto protocol, the hydro power in British Columbia and Alberta will presumably be applied to their own compliance requirements.<sup>19</sup> A more realistic scenario is to assume that load growth is met with combined-cycle natural gas plants, which have CO<sub>2</sub> emissions much lower than coal plants, but significantly above the zero-carbon nuclear, hydro, and renewable energy sources.

If we follow this alternative assumption, again accounting for 65-75 TWh of additional renewable energy, then the five states would have to generate an additional 85-100 TWh of energy from combined cycle gas to meet load growth. It would also result in about 36-43 new MMT of CO<sub>2</sub> emissions. If these five states abandoned all the coal plants from which they currently consume energy, and instead bought power from new combined-cycle gas plants, this would be about sufficient to meet 1990 CO<sub>2</sub> targets if load growth were at the low end of our estimates.<sup>20</sup> The implied new 200 TWh of natural gas energy

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<sup>19</sup> Interestingly, the Kyoto Protocols are effectively a producer-based standard. In theory Canadian generation would be available for export to the US, since coal power imported from the US to offset these exports would not count against Canadian Kyoto targets.

<sup>20</sup> Assuming an emissions rate of 850 lbs/MWh (or .425 MMT/TWh) for CC gas, 85-100 TWh of new energy results in roughly an additional 36-43 MMT of carbon on top of the 27 MMT of reduction from 2004 levels need to get down to 1990 levels. So, in addition to the CC gas needed to meet load growth, additional investment is necessary to reach the carbon goals. Swapping 1 TWh of CC gas for 1 TWh of coal results in a carbon savings

translates into about 25,000 MW of new generation capacity operating at a 90% capacity factor. This is a significant investment, but hardly transformational.<sup>21</sup> Consider that a similar amount of combined-cycle gas capacity came online in the western US between 1999 and 2005. If load growth were at the high end of our estimates, measures beyond discarding all coal generation and the current RPS would be required.

In sum, as with the California-only calculations, our analysis suggests that even if carbon limitations are expanded to cover Arizona, New Mexico, Oregon and Washington, the biggest single driver towards less carbon-intensive electricity generation is likely to be the renewable portfolio standards.

### **3.0 Implications for California**

Our examination of California's position in the western electricity market indicates that there are significant limits to the state's ability to unilaterally impact carbon emissions from the electricity sector. Two of the main policy tools under consideration are source-specific regulations of plant emissions and a cap-and-trade system for trading carbon emission credits. Our analysis indicates that either option could lead to an outcome of "exporting" California's emissions, at least on paper. The net impact of carbon emissions from electricity generation sources would be minimal. If California were truly going it alone in its quest to limit GHG emissions, it appears that more direct regulatory interventions, such as directly funding power plants with low carbon emissions, will be necessary to have an impact on overall emissions.

The outlook for a cap-and-trade system brightens somewhat if it is extended in scope to include Washington, Oregon, Arizona, and New Mexico. Even a producer-based standard applied to these five states would require the closure of major coal-producing facilities for compliance. For the overall impact to be significant, however, these plants need to be replaced by something cleaner, instead of just by a coal plant located outside of the five states. A load-based standard would likely have more impact, but even with a cap-and-trade system encompassing these five states, the biggest driver for change remains the renewable portfolio standards.

These results highlight an important question. What is California actually trying to achieve with its GHG emissions policies? Are California's goals truly limited to forcing down the carbon footprint from activities within the state, as the various legislative initiatives articulate? If so, one must keep in mind that the net carbon equivalent reductions from California's policies, even if it achieves all its goals without

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of .575 MMT, and there were about 105 TWh of energy from coal consumed in these five states in 2004. If the five states consumed no power generated from coal, and it were replaced by new CC gas, this would "save" about 60 MMT of carbon.

<sup>21</sup> Of course, a large expansion of natural gas-fired generation could have significant impacts on the market for natural gas in the West.

circumvention would amount to less than 200 MMTCE economy-wide, while China's emissions are forecasted to rise by several *thousand* MMTCE by 2015.<sup>22</sup>

Given this sobering fact, it becomes clear that these initiatives are pointless unless they help to induce change beyond California. The question therefore becomes, what attributes would make California's policies most likely to have an impact beyond the state's borders? There are at least two potential answers to this question. First, California's actions may influence the adoption of GHG regulations elsewhere, and second, California's policies may influence the specific technologies used to reduce GHG emissions elsewhere.

There is already quite a bit of momentum for GHG regulations outside of California. There is a reasonable argument to make that the specific policies adopted by California do not matter that much in terms of influencing other jurisdictions, simply the fact that California is trying to do something on this issue could help spur other jurisdictions to action. Under this form of the "leading by example" argument, the specifics of the example may not matter much.

Still, it is worth considering that the goal of reaching 1990 emissions levels by 2020, at least in the five western states might be achievable through relatively conventional means – widespread substitution of natural gas for coal production along with continued expansion of wind and other renewable sources. Unfortunately, these means are likely insufficient to meet the more ambitious targets necessary to achieve stability in global concentration of CO<sub>2</sub>. Nor is it likely that deploying further financial resources to these conventional technologies would lead to the kind of "game-changing" innovations that may be necessary for dramatic reductions below 1990 levels. It is very possible that most of the great efficiencies to be had from wind and natural gas production have already been captured.

In light of this argument, truly expanding the impact of California's policies to a global level may require innovation in transformational technologies. Developing countries may only be persuaded to adopt clean technologies if they are demonstrated to actually be less expensive than conventional ones. This argues for focusing a GHG policy more on high-risk, high-return technologies that could truly transform the global energy picture. While the renewable portfolio standards encourage investment in new, low carbon technologies, they are input-based standards and provide no incentives for investment in other potentially important low carbon electricity generation technologies, such as geological carbon sequestration. This highlights the conventional problem with targeted subsidies—by picking technologies, policymakers may be overlooking other technologies that could be more attractive.

Returning to the question of influencing policy within the United States, it is important to remember that, while a cap-and-trade program on a local level (where "local" could even be as large as the west coast) may be ineffectual, it is a much more appealing tool when

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<sup>22</sup> See Auffhammer and Carson (2006).

applied on a national level. One could think of California's current policy efforts as an attempt to design a regulatory policy and infrastructure that could be readily scalable to the national level. Viewed from this perspective, the question of whether GHG policies have an immediate impact on Californian's behavior is not of central importance. After all, even if we hit California's own targets, this amounts to a relatively small drop in the global carbon bucket. What is important is developing a policy that is sensible if applied to the nation and beyond.



## Data Appendix

This appendix describes the data sources and underlying assumption reflected in the analyses described in the text.

### Supply

#### *Overview*

2004 WECC (and sub-NERC region) energy supply (in MWhs) is from the Platts Powerdat database ([www.platts.com](http://www.platts.com)) and is supplemented with Platts Basecase database. Platts' Powerdat supply data is from the RDI modeled production costs query and information is from EIA-906 and FERC form 423. From this database the following plant level data is used: MW, net generation (MWh), capacity factor, prime mover, primary fuel, plant owner, and heat rate. This database contains a separate record for each plant by prime mover type and by ownership. Since the policies under review address the unit instead of the plant, concern was taken to make sure that the data in this form does not overlook the important unit specific factors such as fuel use and capacity factors. This query produces 1,208 plants.

Platts Basecase database (Utility/Non Utility Unit Ownership query) was used to supplement the Powerdat data with plants less than 50MW that were not captured in the main query. This database uses data from EIA forms EIA-411 and EIA-860. An additional 427 plants were added to the database with this method. Capacity factors for these plants are estimated using the average capacity factors for plants with the same fuel type already present in our database. For fuel types for which there was no known capacity factor, the average capacity factor (.474) of the database is used.

The total WECC energy supply used here does not include Canadian or Mexican plants in WECC. The WECC includes Washington, Oregon, California, Idaho, Nevada, Wyoming, Utah, Arizona, Colorado, the bulk of Montana and New Mexico, plus western portions of Texas, and South Dakota. It also includes the Canadian provinces British Columbia and Alberta, and the northern portion of Baja California, Mexico.

Mohave generating plant is included in the database, however the units currently owned by California utilities are not considered part of their portfolio due to reports that these utilities will discontinue their involvement with the plant.

#### *SB 1368 specific*

For the SB 1368 analysis, supply with a capacity factor > 60% and hydro and wind facilities were designated as baseload. SB 1368-compliant plants are those plants that meet the baseload criteria and have a CO<sub>2</sub> emissions rate equal or less than 1,000lbsCO<sub>2</sub>/MWh.

## **Demand**

### *SB 1368 specific*

Hourly 2004 demand data for California is used to determine 60% demand. This data is from Platts Powerdat database ([www.platts.com](http://www.platts.com)) and from its NERC Sub-Region Hourly Load query. The hourly load data is from EIA-704.

### *AB32 specific*

2020 demand for the following states (AZ, CA, MT, NM, NV, OR, WA) is calculated two ways: using 2005 demand from EIA form 861 (Retail Sales of Electricity by State by Sector by Provider) and assumes an average 1.98% growth rate for each of the states and using the same data and using an average growth rate of 1.5%. 1.98% is the 10 year average demand for states in WECC region (the above states plus WY, Utah, and ID). 1.5% is used as a more conservative estimate since individual state growth largely varied over the period. Various sources were analyzed to determine state level demand forecasts. Other sources considered: 1. EIA 861 state level data average 5 year and 10 year historical growth rates (resulted in average state rates of -1% to 5%) The average for all states was 1-2%. 2. The WECC 2005 Information Summary provides a CAGR of 2.4% for the WECC region (which includes some states not considered in this analysis). 3. The California Energy Commission forecasts of 2005-2020 demand for CA have an average growth rate of 1.14% rate.

## **CO2 emissions**

### *1990 emissions data*

1990 emissions data is from the EIA's Electric Power Annual with data for 2005 (U.S. Electric Power Industry Estimated Emissions by State (EIA-767 and EIA-906)) and is used to determine the cap targets.

### *2004 emissions data*

2004 emissions data is used to determine the emissions from existing generation. It is assumed that in 2020 capacity factors and emissions rates will be the same.

Since emissions' data was not available for all plants, heat rate is used to estimate the CO<sub>2</sub>lbs/MWh emissions rate for all the plants. A regression of heat rate on CO<sub>2</sub>lbs/MWh was conducted using reported heat rate and CO<sub>2</sub>lbs/MWh data from a subset of plants for which such data was available from the EPA Continuous Emissions Monitoring Systems (CEMS) database. Plants were analyzed by fuel type and the following regressions were calculated:

	Mean CO2lbs/MWh	Mean Heat Rate/kWh
Gas Plants	1,519.6	12,638.4
Coal Plants	2,328.3	11,363.3

Fuel type	Year	CO2lbs/net MWh =	constant	SE of constant	B1HR(BT U/MWH)	SE of B1	t-test	P-value	R^2	Correlation
Gas	2000-2005		14.9536	18.7	0.0001191	6.54E-07	181.92	0.000	0.976	0.9881
Coal (SUB and BIT)	2000-2005		2.95696	7.5	0.0002046	6.58E-07	310.97	0.000	0.997	0.9987

The CO2 emissions rate for the following fuels, geothermal, wood, biogas, refuse, and landfill gas, were estimated due to lack of sufficient data to run a regression analysis. The records that were available for these fuel types all had CO2 emissions rates of zero, leading to the assignment of zero as the appropriate CO2 emissions rate for these fuels. Due to limited data, oil and petroleum coke emissions were estimated using the coal regression. Oil emissions are similar to coal (1.969 lbs/kWh as compared to 2.095lbs/kWh) and both fuel types have similar heat rates. These fuel sources represent 4.4% of the total MWh.

### Heat rates

Heat rates for plants are from the previously mentioned Platts Powerdat and Basecase databases. Average heat rate calculation: Calculated by dividing the total Btu content of fuel burned for generation by the resulting net kilowatt-hour generation. Calculation is as follows:  $\text{sum of } [(fuel \text{ quantity} \times \text{conversion factor: } 42(\text{oil})/1,000(\text{gas})/2,000(\text{coal/trash/wood})) \times \text{fuel BTU}] / \text{net generation MWh}$ . For example, a station that burns 45,570 tons of coal rated at 11,461 btu/lb, producing 110,700 MWh would have a heat rate calculation =  $((45.570 \times 2000) \times 11461)$  divided by 110700, = 9436 heat rate.

### RPS

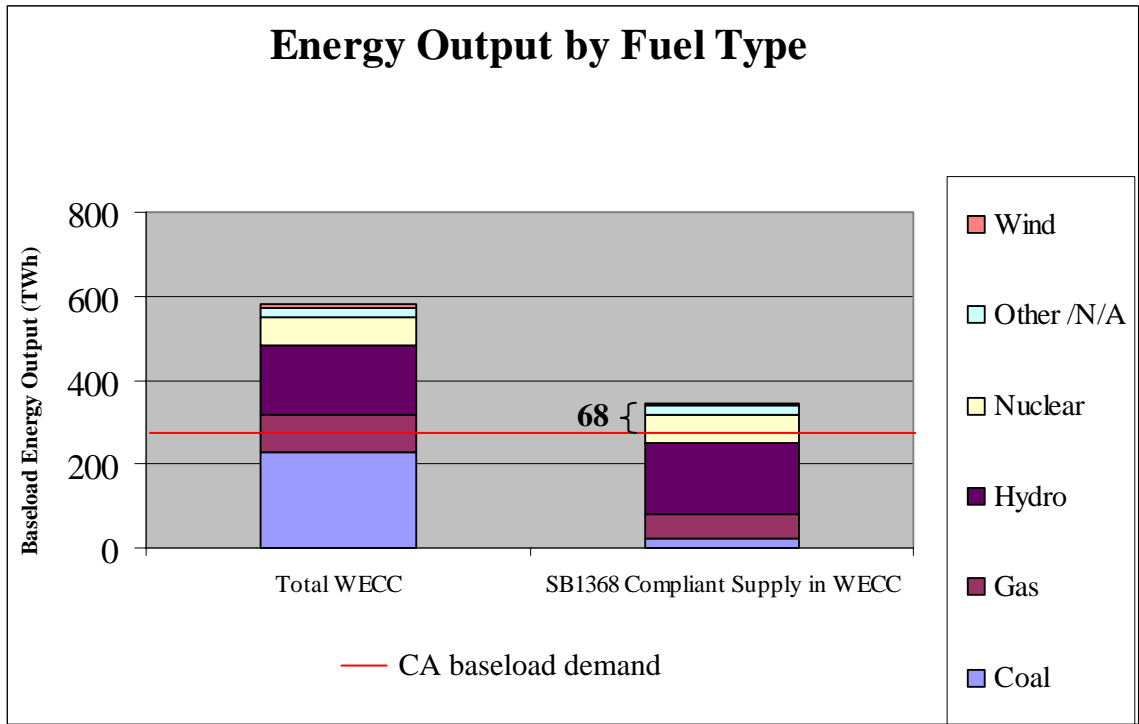
Information on the RPS programs of states in the WECC is from The Database for Incentives for Renewables and Energy Efficiency <http://www.dsireusa.org/> and review of state documents. Expected RPS TWhs is calculated as:  $\% \text{ target} \times 2020 \text{ demand forecast}$ . See above for more detail on state demand forecasts.

## References

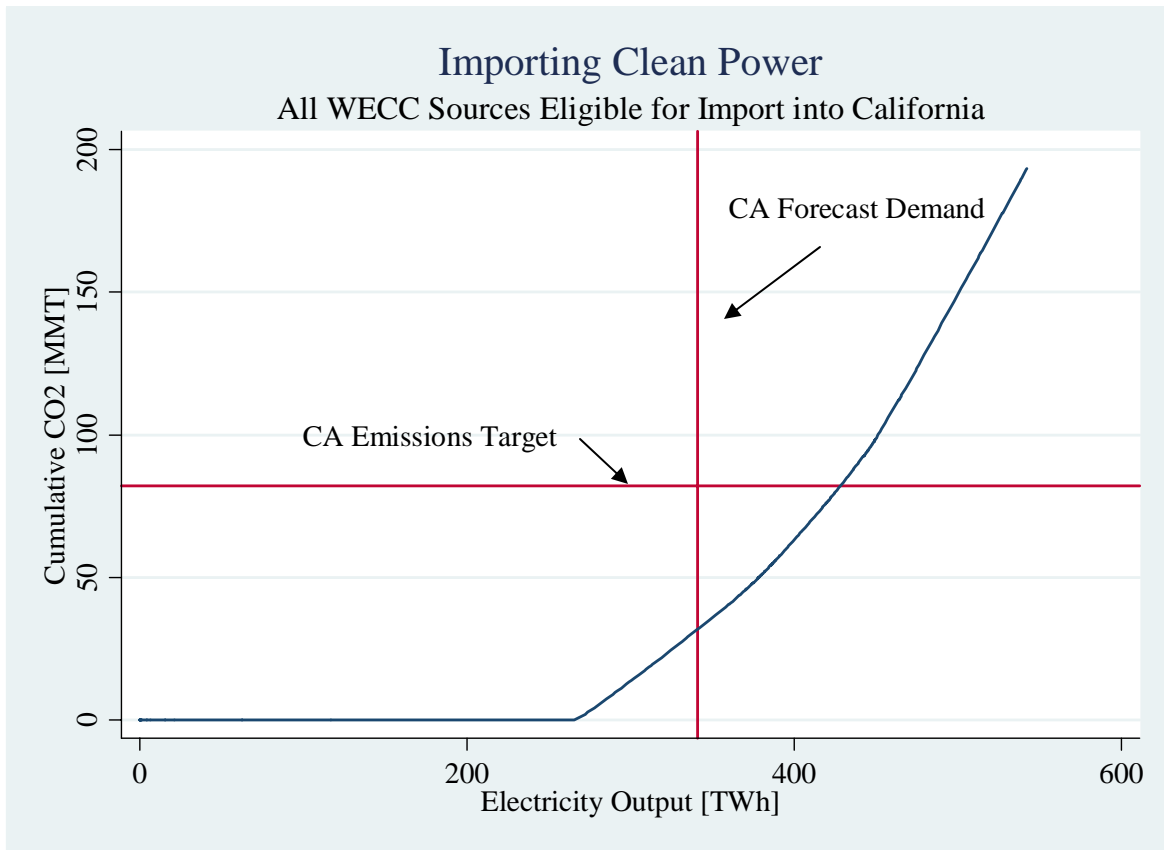
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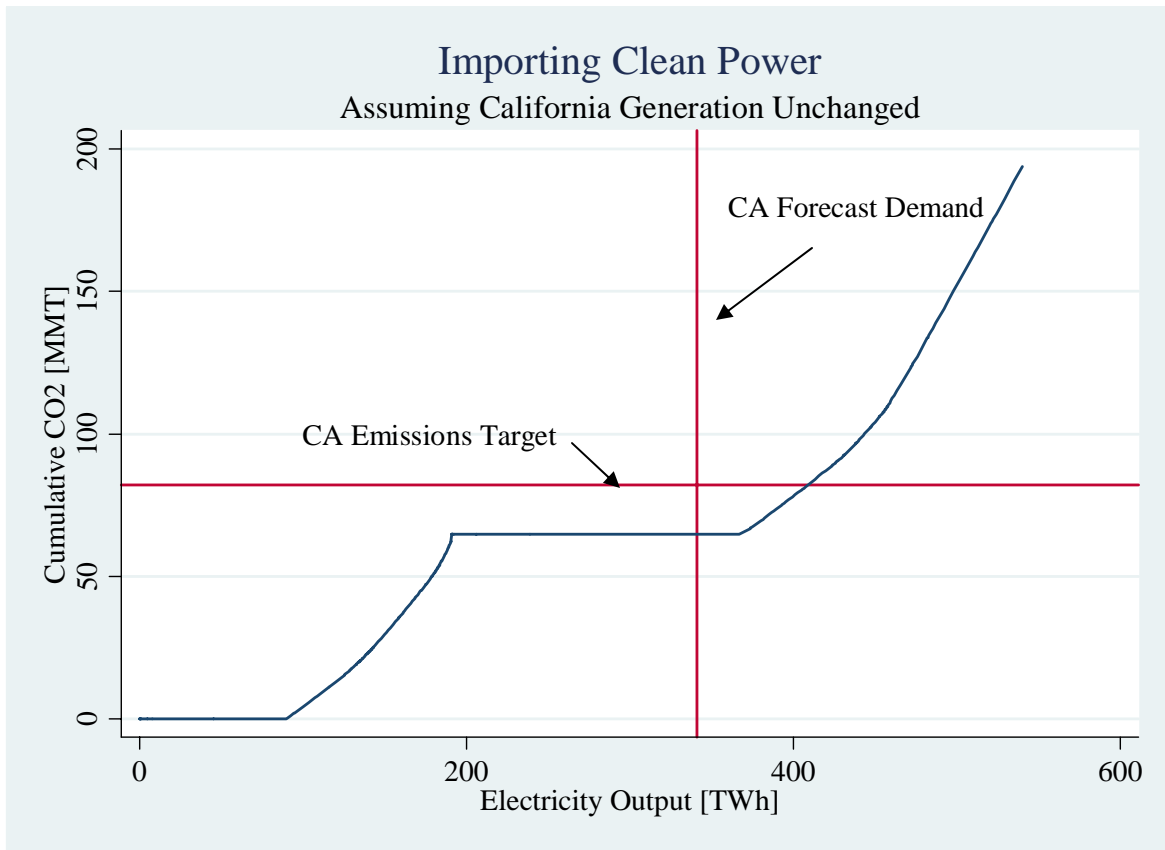
Figure 1



**Figure 2**



**Figure 3**





**Table 1: Renewable Supply in the West**

State	2005 Renewable Supply		Target Renewable Supply %	Future Renewable Supply	
	<i>TWh</i>	<i>% of state load</i>		<i>TWh 2020<sup>(1)</sup></i>	<i>Date Target to be Met</i>
<b>AZ</b>	--	--	15%	14.0	2025
<b>CA</b>	23.8	9.4%	20%	68.2	2010
<b>CO</b>	.8	1.7%	10%	6.5	2015
<b>ID</b>	.6	2.6%	--	--	--
<b>MT</b>	.1	0.5%	15%	2.7	2015
<b>NV</b>	1.6	4.9%	20%	8.7	2015
<b>NM</b>	.5	2.5%	10%	2.8	2011
<b>OR</b>	1.1	2.4%	--	--	--
<b>UT</b>	.2	0.8%	--	--	--
<b>WA</b>	2.0	2.4%	15%	16.8	2020
<b>WY</b>	.6	4.2%	--	--	--

<sup>(1)</sup> Assumes targets met but not exceeded by 2020. See data appendix for 2020 state demand calculations.

Sources: 2005 renewable supply: *Electric Power Monthly*, March 2006, Table 1.14B

2005 state load: *Electric Power Annual 2005 – State Data Tables*

[http://www.eia.doe.gov/cneaf/electricity/epa/epa\\_sprdshts.html](http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html)

**Table 2: Energy Produced in 2004 by Major Fuel Source and Sub-Region (TWh)**

	<b>California</b>	<b>AZ-NM</b>	<b>OR-WA</b>	<b>Rest of WECC</b>	<i><b>Total WECC</b></i>	<i><b>% Total WECC</b></i>
<b>Large Hydro</b>	29.6	6.9	101.5	17.5	<i>155.5</i>	<i>23%</i>
<b>Nuclear</b>	30.3	28.1	9.0	0	<i>67.4</i>	<i>10%</i>
<b>Renewables</b>	28.5	1.0	5.1	6.1	<i>40.7</i>	<i>6%</i>
<b>Natural Gas</b>	96.2	32.4	22.5	36.9	<i>188</i>	<i>27%</i>
<b>Oil</b>	3.4	<.1	.3	.2	<i>3.9</i>	<i>1%</i>
<b>Coal</b>	3.0	65.8	14.0	146.2	<i>229</i>	<i>33%</i>

Source: Platt's Powerdat database. See appendix for details.

**Table 3: Growth in CO2 Emissions from Electricity by State, 1990-2004**

<b>State</b>	<b>1990 CO2 emissions (MMT)</b>	<b>2004 CO2 emissions (MMT)</b>	<b>% Change</b>
AZ	33.2	52.3	57%
CA	53.2	59.8	13%
CO	30.9	40.6	31%
ID	0.5	1.3	167%
MT	15.9	19.3	22%
NV	17.7	25.0	41%
NM	27.8	31.3	12%
OR	2.0	9.2	362%
UT	29.3	35.1	20%
WA	8.4	15.0	77%
WY	40.6	46.0	13%
<b>Total</b>	<b>259.4</b>	<b>334.8</b>	<b>29%</b>

Source: EIA. Electric Power Annual with data for 2005  
Report Released: October 4, 2006 U.S. Electric Power Industry Estimated Emissions by State (EIA-767 and EIA-906)