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The Implementation of California AB 32 and its Impact on Wholesale Electricity Markets

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Abstract:

California is considering the adoption of a cap-and-trade regulatory mechanism for regulating the greenhouse gas emissions from electricity and perhaps other industries. Two options have been widely discussed for implementing cap-and-trade in the electricity industry. The first is to regulate the emissions from electricity at the load-serving entity (LSE) level. The second option for implementation of cap-and-trade has been called the "first-seller" approach. Conceptually, under first-seller, individual sources (i.e. power plants) within California would be responsible for their emissions, as with traditional cap-and-trade systems. Emissions from imports would be assigned to the "importing firm." An option that has not been as widely discussed is to implement a pure source-based system within California, effectively excluding imports from the cap-and-trade system altogether. This paper examines these three approaches to implementing cap-and-trade for California's electricity sector. The paper surveys many of the issues relating to measurement and the impacts on bidding and scheduling incentives that are created by the various regulatory regimes.

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Summary

California is considering the adoption of a cap-and-trade regulatory mechanism for regulating the greenhouse gas emissions from electricity and perhaps other industries. A cap-and-trade system would fix an overall limit on GHG emissions from the industry, while allowing for flexibility in compliance. While regulation would set the aggregate limit, a trading system would determine the distribution of emissions reductions across firms and sources. However, the implementation of cap-and-trade in the electricity industry is made more difficult by the fact that the California electricity market is highly integrated with neighboring states. If those states do not participate in the cap-and-trade system, it becomes more difficult to regulate the emissions arising from this imported power.

Two options have been widely discussed for implementing cap-and-trade in the electricity industry. The first is to regulate the emissions from electricity at the load-serving entity (LSE) level. Under this load-based approach, a buyer of electricity would be responsible for the GHG emitted by the sources selling power to it. Implementation of the load-based approach necessitates a matching of the output of power plants to buying LSEs that is difficult to accomplish in the absence of plant-based purchase contracts or outright ownership of facilities by LSEs. In particular, it is impossible to accomplish a specific matching for sales through pool-based markets, such as those operated by the California ISO (CAISO). Instead, an administrative average value would likely be used.

This *assignment problem*, the matching of sources to consumers (or loads), can create perverse incentives for firms to structure their transactions in order to avoid a proper accounting of their emissions. Consider the case where a default emissions value for purchases out of pool-based markets is used. Those sources cleaner than the profile will want to avoid sales through these markets, as their buyers will be responsible for "dirtier" emissions than those created by the true source. Conversely, dirty sources will prefer to mask their emissions by selling into the pool, where the costs of those emissions will be averaged over all buyers.

The second widely discussed option for implementation of cap-and-trade has been called the "first-seller" approach. This approach would assign responsibilities for emissions to the firm that first sells the power within California. An exact definition of a first-seller, and its legal and regulatory status, has yet to be articulated. Conceptually, however, individual sources (i.e. power plants) within California would be responsible for their emissions, as with traditional cap-and-trade systems. Emissions from imports would be assigned to the "importing firm," perhaps a scheduling coordinator in the CAISO markets. A major appeal of the first-seller approach is that it, in theory, avoids the difficult assignment problem for plants within the State. However, as with the load-based approach, problems with the assignment of emissions from imports remain. Some perverse incentives will likely be created, although these would be minimized for plants located inside the state.

The regulation of electricity imports poses a challenge under any cap-and-trade regime. Under a load-based or first-seller approach, there are concerns that firms can "game" the emissions values assigned to generic import transactions. Even more serious is the prospect that California's GHG regulation could cause a *reshuffling* of sources and customers amongst the western markets. Clean sources that have, to date, sold power to other states could shift their sales to California. The dirty sources providing California's power would divert their supplies to consumers in unregulated states. Although California electricity would appear cleaner on paper, net GHG emissions in the west would remain unchanged. Various administrative rules relating to the accounting of emissions from imports could reduce, or even eliminate, the incentives to shuffle purchases. These rules can blunt the accuracy of emissions measurement and dilute the incentives of firms to actually reduce emissions, however, and could prompt legal challenges. Fixes that would combat the reshuffling problem could, ironically, undue the very legal advantages that made the load-based approach attractive in the first place.

A last option that has not been as widely discussed is to implement a pure source-based system within California, effectively excluding imports from the cap-and-trade system altogether. This is the approach that has been adopted for the Regional Greenhouse Gas Initiative (RGGI) in the northeastern U.S. Since the law requiring GHG reductions, AB 32 specifically states that regulators must consider the GHG impact of electricity imports, some other regulatory mechanism would have to be deployed to deal with imports that would operate in parallel to the cap-and trade system. The appeal of the pure source-based approach is that it avoids the assignment problem altogether, sources are responsible for their own emissions. The risk is that it could magnify the incentive to shift physical electricity production to other states outside of the cap-and-trade system. Such migration of production to avoid environmental regulation is known as regulatory leakage. Regulatory oversight by the CPUC and other institutions, as well as the prospect of expanding the cap-and-trade system to include larger regions could mitigate the degree and severity of the leakage problem.

Indeed, it appears that traditional regulation will play a prominent role, regardless of the ultimate form of the cap-and-trade system. This will be necessary to deal with imported power, a problem under all approaches. It will also limit the impact of the cap-and-trade system on the electricity industry, as the flexibility provided by cap-and-trade will be constrained by the overlay of other policies. Given this fact, the development of a system that is, or can readily become, expanded to a regional or national system should be a primary focus. A cap-and-trade system that designed for local purposes could very well prove counter-productive in the long-run.

1.0 Introduction

The state of California is currently pursuing a broad portfolio of policies that are aimed, directly and indirectly, at reducing emissions of greenhouse gasses (GHG). Many of these policies are focused on two key sectors, the electricity sector and automotive transportation. Currently electricity accounts for roughly 20% of California's GHG emissions, while transportation as a whole accounts for roughly 40%. The most prominent policy initiative is the "Global Warming Solutions Act," California assembly bill 32 (AB 32), which stipulates that California's overall GHG emissions be reduced to 1990 levels by 2020.

Conceptually, AB 32 is seen as an umbrella under which a diverse set of regulatory initiatives will be combined to reach the aggregate emissions target. The bill itself does not identify specific policies for achieving these targets, or the relative burden to be borne by specific industries. The bill instead assigns the California Air Resources Board (CARB) responsibility for determining the specifics of implementation.

Market-based regulatory tools, such as a cap-and-trade program, have been widely discussed but are also somewhat controversial. A Market Advisory Committee (MAC) was formed by the California EPA to specifically consider the merits and possible design of a cap-and-trade system for AB 32 and issued its report on June 30.[1] The California Public Utilities Commission (CPUC) has also been a prominent player in the cap-and-trade design process. Prior to AB 32, the CPUC had initiated a process for regulating GHG through the utility companies under its jurisdiction. Since the adoption of AB 32, the CPUC, along with the California Energy Commission (CEC) has led a stakeholder process on the design and implementation of cap and trade. This process will result in a recommendation to CARB about the ultimate form that such regulations should take.

Under AB 32, CARB must first establish emissions reporting protocols for various industries by 2008. A scoping plan for achieving the maximum technologically feasible and cost-effective GHG reductions must be adopted by January 1, 2009. The actual regulations to achieve the 2020 goals must be adopted by 2011 and enforced starting in 2012. Any cap-and-trade program adopted under AB 32 would therefore become operational in 2012.

Since at least two distinct frameworks of a cap-and-trade system for GHG are being seriously considered, it is important to examine the likely implications of each system when applied to California. The focus here is on the electricity industry, and in particular on the impacts of various implementation schemes on the operations and performance of the wholesale electricity market.

One key debate that has evolved over the last several months regards the point of compliance for enforcement of GHG reductions. In essence, the question is whether

[1] See "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California" Recommendations of the Market Advisory Committee to the California Air Resources Board, June 30, 2007.

producers or purchasers of electricity should be responsible for the GHG emissions associated with the electricity that is transacted. As I discuss below, the choice of compliance responsibility can have indirect effects on the scheduling and contracting practices of market-participants. Regardless of the point-of-compliance, there are additional concerns about the impacts of a California-only cap-and-trade program implemented within the integrated western electricity market.

2.0 Implementation of Cap and Trade under AB 32

Among the most prominent proposals for implementing AB 32 is the establishment of a cap-and-trade program for CO2, and perhaps other GHG. A cap-and-trade program establishes an aggregate limit on the amount of pollution that can be released in a certain area over a given time frame (for example, a limit on the amount of CO2 produced from various sources during a year). The cap-and-trade system, although it applies an overall regional limit to total emissions (the cap), 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 most efficiently reduce their emissions will sell credits to firms that find it very expensive to reduce (the trade).

The choice of cap-and-trade as a policy instrument for implementing AB 32 remains controversial. The bill itself merely states that cap-and-trade may be considered as an option. The number and identities of the industries to be included under a cap-and-trade system is also uncertain. Originally it was anticipated that only large stationary industries (cement, refining, electricity) would be included, but the MAC has recommended also including the transportation sector through the upstream regulation of sales of refined petroleum products.

With regards to the electricity industry, the major issue has been the choice of the "point of compliance" for cap-and-trade. In other words, the question is where in the supply chain should responsibility for carbon emissions be assigned? This question is intricately linked with the realities of California's position in the western electricity market. Currently Californians import about one-quarter of the electricity they consume from neighboring states. More significantly, these imports reflect, on paper, disproportionately dirty, accounting for over half of the CO2 credited to California electricity demand.[2]

These facts matter because a traditional *source-based* cap-and-trade system would apply only to plants physically located inside California. Under a source-based system, the facility (source) that produces the pollution is responsible for complying with the emissions cap. Such sources would either have to reduce emissions or acquire credits to

[2] The definition of an "import" can be somewhat confusing here as much of the coal-fired electricity imported into California is generated from plants with close financial and electrical connections to California firms. The California Energy Commission for example, considers much of this electricity to be sourced "within" California even though the plants are physically located outside California's borders.

comply. A source-based system limited to California, however, would not directly address over half the GHG emission attributed to electricity.[3]

Further, sources could appear to "comply" with California's cap by effectively moving out of the state. The concern is that the regulation would encourage producers to retire (or reduce output from) plants inside the state, and replace the production with increased imports. These imports could very likely be dirtier than the local production they are replacing. This phenomenon, in which firms respond to environmental restrictions by physically relocating production, is known as *leakage*.

Initially the CPUC proposed a *load-based* cap-and-trade approach, where the purchasing load-serving entities (LSEs) are responsible for the carbon emitted by the sources from which they purchase electricity. Under this system, it is the LSEs that would be required to either procure electricity from cleaner resources or acquire offsetting emissions credits.

One of the strongest appeals of the load-based approach is its perceived ability to withstand legal challenges. It is generally accepted that California institutions cannot explicitly regulate the production of electricity in other states. However, regulating the *purchases* of electricity would place the point of regulation upon firms operating strictly within California. As with the RPS, this appears to be acceptable within the confines of the constitution's commerce clause as long the regulation does not explicitly treat purchases from imports differently than those from production within the state.

There are several significant measurement issues associated with implementing a load-based cap for carbon that are discussed below. In addition to the perceived ability to better "reach" sources outside of California, some have made the controversial argument that the load-based cap provides a stronger incentive to LSEs to reduce their energy purchases through energy efficiency. The argument that load-based assignment of carbon responsibilities would enhance energy efficiency is rooted in a behavioral economic perspective that the costs of carbon would be perceived as more "direct" if the LSE had to go out and acquire carbon credits in addition to its energy costs, as opposed to having the carbon costs implicitly reflected in the costs of the energy itself, as it would be under a source-based or first-seller approach. One weakness of this argument is that LSEs are overwhelmingly municipal or regulated entities, and therefore do not respond directly to market signals, but rather political and regulatory incentives. Indeed, LSEs who are allowed to pass on the costs of emissions credits to captive ratepayers could actually have less of an incentive to reduce the costs of those credits. State policy-makers appear committed to providing large funding for energy efficiency programs through traditional regulatory mechanisms, regardless of the cap-and-trade policy that is eventually adopted.

As an alternative to the load-based approach, several participants have proposed a *first-seller* approach to compliance. The first-seller approach attempts to address the legal concerns about California's authority to regulate imports, while avoiding some of the

[3] The ability of California regulators to place an environmental "tax," or its equivalent on imports is restricted by the interstate commerce clause of the constitution.

measurement and incentive problems of the load-based approach. The first-seller approach would define the point of compliance as the first point of sale *within the state*. Thus a purchase from a plant within the state would be regulated at its source, while an import would in effect be regulated at the point of import into California. In effect, this combines a source-based program within the state with some kind of responsibility on importers to cover the emissions from the original sources of the out-of-state power. As with the load-based approach, there are measurement issues associated with the assignment of pollution to specific import transactions.

It is important to note that at this point, the first-seller approach is best considered a concept, rather than a concrete proposal. An exact legal definition of a first-seller has not yet been developed.

3.0 Wholesale Electricity Markets and GHG Regulations

As summarized in the previous section, there are four broad options for implementing AB 32. The first is a source-based cap-and-trade system in which imports do not participate. Imports would have to be dealt with through alternative regulatory measures. The second option is a load-based cap-and-trade system, in which the emissions from imports would be assigned to the LSE who purchases the energy. The third is the first-seller approach, in which sources are regulated in the state, and the pollution from imports would be assigned to the "importer." The last option would be to eschew cap-and-trade altogether in favor of more direct regulatory tools. In the following section, I discuss the implications of these options for measurement, scheduling and pricing.

3.1 Measuring and assigning emissions

One of the first tasks necessary for implementing cap and trade is the development of protocols for measuring the emissions firms are responsible for under the cap. The aggregate emissions of all the firms must then fall under the cap – subject to any "banking" or "borrowing" provisions that may be allowed. In the California GHG context, this can require two steps: measuring the physical emissions at a power plant, and assigning those emissions to the party subject to the cap (if its not the power plant).

Source-based

Under a source-based system, only the first of these two steps are required. The owner of the power plant would be responsible for the emissions, so the assignment problem is trivial. For conventional power plants, the measurement of physical GHG emissions is not seen as a significant problem, even for those plants located outside of California. Most large-scale plants are already equipped with continuous emissions monitoring (CEMS) devices for participation in the EPA's SO2 trading program. Data from these plants, reporting the hourly emissions of several pollutants including CO2, are provided to EPA and are available on the internet.[4]

The adoption of a source-based approach would also involve a different measurement of the target levels to be achieved under cap-and-trade. For example, the 1990 levels for GHG emissions that would fall under the cap would not include imports, but rather would be based upon some measure of current or historic domestic production. The remainder, attributable to imports, would still fall under the AB 32 targets, but not participate in the cap-and-trade regime.

Load-based

The measurement difficulties arise when the plant emissions must be assigned to a firm other than the plant owner, as they would under both a load-based and first-seller scheme. Under the load-based approach, LSEs would be assigned the emissions of the plants from which they "purchase" power. This kind of tracking "upstream" is difficult for any commodity, but especially so in the case of electricity. The transportation and "delivery" of electricity has always been more legal fictions than physically meaningful concepts in electricity markets. In reality, all electricity systems pool sources and demand, and no consumers can reliably be said to take delivery from a specific source.

For purposes of tracking therefore, the emissions would have to be assigned via financial arrangements, rather than physical measurements. For cases where an LSE owns a plant, or has a contract for the full (or fractional) output of a specific, known plant, this is relatively straightforward. The problem is that many power purchase arrangements can be quite complex, and may not link the source of the energy to a single facility. For example, it is not uncommon for LSEs to procure energy supplies under "liquidated damages contracts." The commitment to supply energy under these contracts is backed by an agreement to pay financial damages if the supplier fails to provide the energy, rather than tied to the output of a specific plant.

One of the most obvious problems with assignment under the load-based approach relates to purchases from the wholesale pool-based markets operated by the California Independent System Operator (CAISO). The CAISO currently operates a real-time balancing market, and is scheduled to implement a day-ahead market (DAM) in early 2008. In both these markets, supply is effectively "pooled" and an aggregated balancing of supply and demand results in a uniform price, subject to locational differences stemming from transmission constraints. There is no pair-wise matching of supply and demand, and therefore no sense that individual buyers from these markets are purchasing from individual sellers. The likely outcome will be that purchases from these markets will be assigned the MWh weighted average of the emissions from all generators

[4] There has been some discussion of whether the reporting of CO2, which has not to date been regulated, is accurate enough under CEMS to be applied to a binding regulatory structure. However, several substitutes, such as basing emissions upon the carbon content and quantity of fuel consumed at plants, are seen as relatively straightforward to implement.

supplying the markets. This can lead to perverse incentives for both purchases and sales into the pool-based markets that are discussed further below.

Market timing presents one of the significant difficulties for tracking emissions through the ISO markets. A reasonably accurate accounting of CO_2 emissions, at least from in-state plants, from ISO purchases could be determined through the CAISO settlements process. However, these details, which clarify which generator produced how much power in a given hour, are only finalized weeks after the actual market prices are set. For an LSE purchasing through the CAISO market, a dynamic updating of the emissions profile of the ISO pool could therefore create potentially large uncertainty about the carbon costs associated with their purchases. This would no doubt make the CAISO markets less attractive.[5]

The alternative is to set a fixed default value that would be updated only periodically and set before the market is run. A recent joint proposal issued by staff of the CPUC and CEC recommends just such an approach for the CAISO markets.[6] Because these values are set in advance, without full knowledge of who is actually selling into these markets, such an accounting will necessarily be inaccurate. The severity of this mismatch is difficult to predict. However, as discussed below, the incentives created by the establishment of the default value will likely exacerbate the magnitude of the error.

First-seller

One of the first challenges with assigning emissions to first-sellers is developing a formal definition of a first-seller. Conceptually, emissions sources within the state would each be considered first-sellers, along with "importing" firms. It is not clear if such a strong differentiation is practical or legal, however. For the CAISO control areas, the natural definition of a first-seller appears to be a *scheduling coordinator* (SC). As a practical matter, the SC seems to be an appealing choice for the point-of-compliance. They are responsible for identifying specific sources of energy to the CAISO as part of the operation of the electricity system. As such it would be relatively straightforward to assign emissions from in-state sources to a specific SC, although with some time lag.

There are legal and jurisdictional issues that would have to be addressed in assigning first-seller responsibilities to an SC or other equivalent party. Unlike an LSE, an SC is an entity that exists primarily to trade wholesale power and therefore falls under the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC). It is not clear whether FERC approval for the regulation of the emissions of an SC would be

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[5] The impacts of such uncertainty will be linked to the regulatory treatment of emissions costs. If those costs are automatically passed on to rate-payers, regulated LSEs will not be impacted. Of course such a pass-through would also largely eliminate the incentives for LSEs to reduce emissions.

[6] See Attachment A of Murtishaw and Griffin, "Joint California Public Utilities Commission and California Energy Commission Staff Proposal for an Electricity Retail Provider GHG report. June, 2007. The report recommends using a CO_2 value of 900 lbs/Mwh for the real-time market and 1000 lbs/Mwh for the DAM. Notably, a lower value for the real-time market would give firms an incentive to shift their purchases from day-ahead to real-time, creating potential reliability problems. These concerns were noted by several stakeholders, including the CAISO, in reply comments to this proposal.

required, or what the implications for interpreting the inter-state commerce clause would be. Another issue is the definition of first-sellers in markets not overseen by the CAISO. The vertically integrated municipal utilities do not "host" markets in the fashion of the CAISO and in effect act as their own schedule coordinators.

Significantly, importers to any control area are not as a rule responsible for identifying the original source of the electricity, but rather identifying the point of import. This is because it is the point of import that matters to the control-area operator responsible for maintaining reliability of its local system.

This raises a second general difficulty with assignment that is shared by the load-based and first-seller approaches: the treatment of imports. Control area operators within California, of which the CAISO is the largest, have limited ability to access real-time data on specific generation outside of their control areas. The system is viewed internally as a combination of supply points consisting of specific generators within a control area, and interconnection points (or inter-ties) with neighboring areas. For purposes of assignment, interconnection points resemble pool-based markets – there is in effect an electrical pooling of supply and consumption. If a given control area (pool) is generating more than it is consuming, the remainder in effect "spills over" into neighboring control areas in the form of imports. Administrative rules of some kind are therefore necessary for assigning emissions under any scheme that attempts to include imports.

The measuring of the emissions "created" by imports into California presents a paradox. Detailed modeling of various neighboring systems and market conditions can yield a relatively precise estimate of the marginal impact of imports. Yet, as discussed below, a more detailed assignment of specific import sources to regulated California entities encourages a "reshuffling" of sources amongst California and non-California buyers. This presents a trade-off to the regulator between accuracy of measurement and limiting the incentive problems provided by those measurements.

3.2 Scheduling, Contracting, and Bidding incentives

Unfortunately, all three potential implementations of cap-and-trade raise the prospect of creating perverse incentives for firm behavior in order to avoid the costs of compliance. The exact nature of the distortions, and their potential impacts, differ considerably.

Source-based Regulations

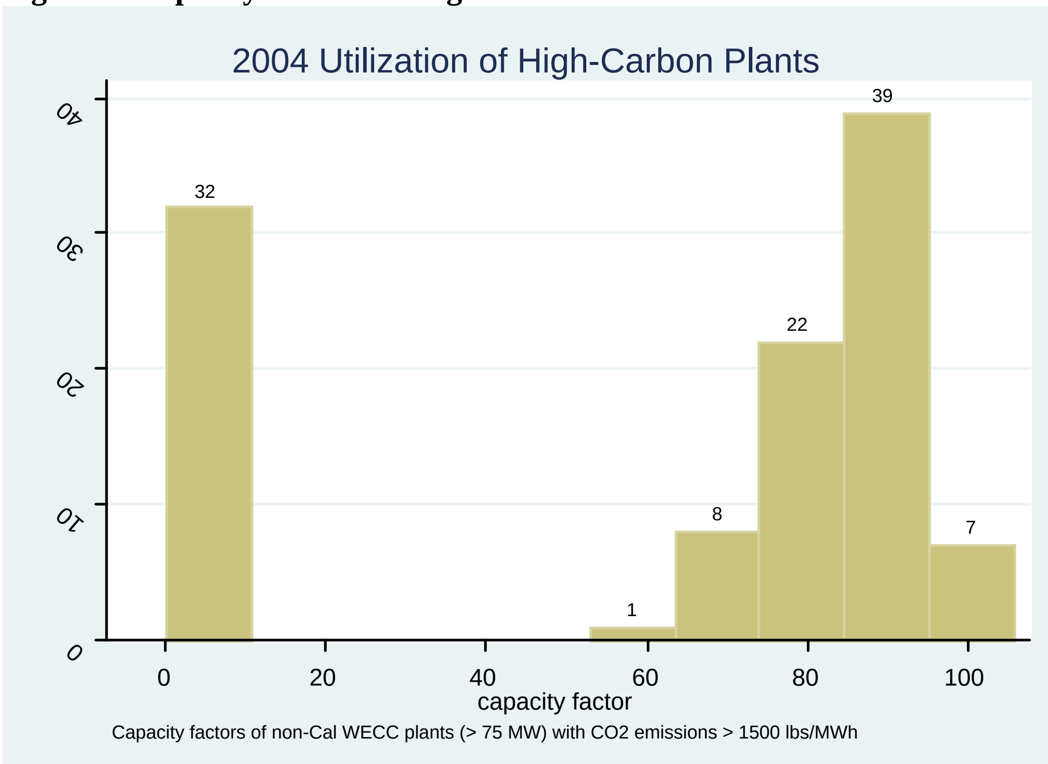
For a source-based system, the concern is leakage. Since imports would not be subject to regulation, there would be a direct savings for firms to shift purchases away from sources within California to imports. In the short-term this would influence contracting and spot purchases. Over a longer horizon, this could lead to an inefficient closure of plants inside the state in favor of new facilities elsewhere.

Given the prominent role of regulation in the industry, it is not clear just how large the leakage effect could be.[7] The CPUC has considerable leverage in guiding the procurement practices of the three investor owned utilities (IOUs) under its jurisdiction. However, a system that constrains the IOUs more than municipal utilities or unregulated energy service providers could create pressure for further migration of customers away from those utilities. Ironically, the fact that California already imports much of its power reduces the room for *further* leakage – much of the leakage has already happened. Of course a source-based system would have no ability to *reduce* emissions from plants outside of the state, so the best one can hope for from a source-based approach is a minimal impact on the operations of plants outside of California. Imports would have to be dealt with through other regulatory mechanisms outside of the cap-and-trade mechanism.

There are several layers of leakage concerns, spanning differing time horizons. The first, and most serious, concern is that relatively clean plants inside California would reduce their output and have the electricity replaced by production from even dirtier plants elsewhere. In this outcome, net emissions from electricity production across the west increase. The risks of this happening are mitigated by the fact that much of the dirty production outside of California is already operating at high capacity factors, and therefore cannot significantly increase production even if it were profitable to do so. As figure 1 demonstrates, the dirtiest plants in the WECC fall into two categories, coal plants with relatively high capacity factors, and combustion turbines with very low capacity factors. Plants in this latter category, while able to produce more energy for import into California, are quite expensive to operate. Thus the carbon price would have to be relatively high to make economic a swap of an efficient (but carbon constrained) California plant with imports that are not carbon constrained.

[7] For a detailed examination of the potential for leakage from a California cap-and-trade system, see Fowlie, Meredith, "Incomplete Environmental Regulation and Leakage in Electricity Markets." University of Michigan Working Paper (2007).

Figure 1: Capacity Factors of High-Carbon Plants



A second related short-term concern would arise from plants in California reducing output to be replaced by *cleaner* production from elsewhere. In the electricity sector, this is a net improvement in emissions quality. However, under a pure source-based system these imports would, in effect, have no emissions at all from the perspective of California regulators. This could free up extra emissions credits that could be used to offset GHG emissions in other industries participating in a cap-and-trade program. Thus the under-counting of emissions from imports in electricity could yield less reductions in other industries than would otherwise occur.

The last concern is over a long-term shift of production to regions beyond the reach of the cap-and-trade regulations. A worst case scenario would involve the construction of new coal facilities in unregulated regions that would sell power into California and replace the output of cleaner natural gas plants currently operating in the state. There are two factors to consider with regards to the long-term leakage problem. First, over the long-term it is widely expected that either a regional or national cap-and-trade system will replace or supplement the one currently under consideration in California. Second, the state and local governments still have a high degree of regulatory influence over the procurement decisions of most LSEs in California. It is highly unlikely that regulators would approve large investments in new coal facilities in any event, regardless of the form that cap-and-trade may take in the industry.

Load-based Regulations

Under a load-based approach to cap-and-trade, the risks of physical leakage are reduced, since even imports will carry some GHG costs with them. Potential problems arise from the fact that the assignment of emissions are tied to financial transactions. Since financial transactions can be quite complex, and are easily made more so, this raises the concern that trading and procurement strategies could be driven more by a desire to evade emissions responsibilities than by economic efficiency.

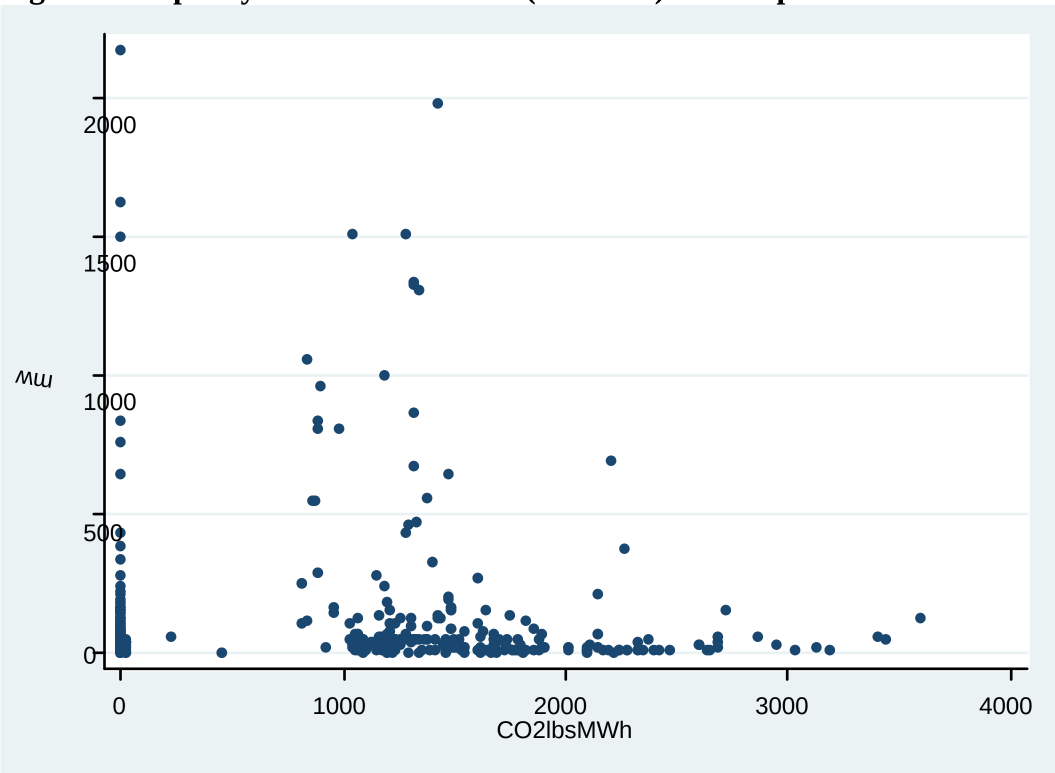
In general, procurement strategies would be influenced by the emissions profile of the source *relative* to the default alternative. The game is one of *beating the average*. For example, if a potential source of power is dirtier than the average in the day ahead (DA) market, both the buyer and seller would prefer to transact through the DA pool rather than directly. The buyer is then assigned only the pool-based average, rather than the larger emissions from the specific source. Conversely, if a source is cleaner than the pool average, a buyer would prefer a bilateral transaction where it could directly enjoy the benefits of the cleaner source profile. A seller would likely prefer this option as it could charge a premium over the pool price reflecting the additional value of its “clean” power to the buyer.

At a minimum, the decisions of individual firms about where and when to transact in California’s electricity market would be influenced by these factors. This would distort, to some degree, the natural choice of such transactions relative to what would happen under a first-seller and source-based (or no) cap-and-trade regimes. If the current proposals are adopted, and purchases from the CAISO are assigned a default value of around 1000 lbs/Mwh of CO2, plants with emissions values below that level could have a strong disincentive to participate in these markets. This would include all of the hydro production that currently serves a critical role in providing certain types of responsive operating reserves.

If the emissions values for the ISO market are frequently updated, this dynamic could result in an unwinding of volume in the DA market. As cleaner supply leaves the DA market, the average would rise. If this average is updated by regulators, still more generation would be cleaner than the new average, and would also leave the DA market. In the extreme, only the most polluting sources would be left in the DA market.

The likelihood of such a death-spiral for the DA market will depend upon the role that GHG costs play in the overall decision-making of firms, including the regulatory treatment of these costs, and the frequency with which the ISO’s emissions profile is updated. If GHG costs are significant, they would likely outweigh the benefits offered to individual firms from participating in the DA market. If a large number of plants feature emissions profiles only slightly better than the pool average, the effect may not be large if the pool is viewed as offering significant value.

Figure 2: Capacity and emissions rate (lbs/Mwh) for CA plants



The distribution of emissions rates from California power plants is illustrated in Figure 2. This figure is a scatter plot of plant capacities and emissions rates, with each dot representing a single plant. Generation facilities with emissions rates less than the proposed benchmark of 1000 lbs/Mwh account for about half the capacity and two-thirds of the energy produced in California. Of this group, most of the capacity and over 60% of the energy comes from sources with extremely low CO2 emissions. Over the entire western market, this "clean" generation accounts for more than half the capacity and about 60% of the energy.

The exact implications for the ISO are also difficult to predict. Firms would still be required to schedule their purchases and production day-ahead, and these bilateral schedules could be linked to specific generation. They could be discouraged from submitting bids to "adjust" these transactions from the preferred scheduled level, because such adjustments would be run through the pool, and therefore subject to the default emissions value of that pool. If such an effect feeds over into the real-time market, a lack of these *adjustment bids* could cause operational difficulties. Importantly, hydro facilities, which would be most penalized by the default emissions value, provide much of the flexible generation the CAISO relies upon to balance the system. There is no question that detrimental incentives will be created, the uncertainty is over how strong those incentives would be.[8]

[8] Another question is the treatment of deviations from day-ahead schedules. Typically a firm that consumes less than it schedules to produce is considered to be selling power back into the real-time market.

In addition to the problems created by assigning emissions from plants purchased through pool-based markets, the load-based approach is also potentially vulnerable to similar incentive problems caused by assigning emissions from imports. Since this is a problem shared by both the load-based and first-seller approaches, I discuss those issues below.

First-seller approach

Assuming that a "first-seller" of energy in California can be satisfactorily defined, many of the incentive issues are similar to those created by the load-based system, with the important difference that these problems would be limited to imported energy and not California generation sources run through the CAISO markets. Any imports that are not linked to contracts will have to be assigned a default value. This would include "generic" imports purchased through the CAISO markets and those purchased under "portfolio" energy agreements, where no single source of the power is identified. The CEC/CPUC staff report recommends separate default values for imports from the Pacific north-west and desert south-west for such purchases.[9]

As with load-based, imports would face a similar incentive to beat the average set as the default emissions value for imports. In this case, firms with contracts for clean energy would choose to identify their sources, while "first-sellers" of dirty sources would choose to import under a generic transaction that would be assigned the standing average emissions value.

Operationally, the consequences are less severe with regards to imports than local plants. First seller could be implemented in such a way that firms are indifferent to using bilateral transactions or the CAISO market. In other words, the problems with identifying the source of imports are shared equally by the CAISO markets and bilateral transactions. The consequences of this self-sorting of imports would therefore largely be financial and environmental. The environmental concern would be that the incentive problems exacerbate the measurement problems. The average emission rate used as standing value for generic imports would become less and less accurate as transactions sort themselves relative to this value. If the value is frequently updated, the unwinding of

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If the emissions profile of the schedules are different than those for the adjustments or deviations from those schedules, this could produce an incentive to enter over(or under)-stated schedules and intentionally deviate from those schedules.

[9] Differentiating the carbon content of imports, even on a large regional scale, is still problematic. There would be a strong incentive for firms to "wheel," at least on paper, power through western states to appear to import from the northwest, as opposed to the southwest. Because there are different institutional approaches to dealing with the shipment of wholesale power across regions, the financial movement of power can diverge from the actual physical movement of power. Trading strategies, such as ENRON"s "death star" trades, have in the past been formulated to take advantage of these kinds of differences in transmission pricing approaches.

this process would leave the standing average at a level equal to the dirtiest plants in the Western market.[10]

If this "default" import emissions value were simply set at the level of the dirtiest plants to begin with, then most firms would have an incentive to claim their imports are coming from a specific, cleaner source. This is not necessarily an appealing prospect from the standpoint of regulators, however. There are additional concerns that a direct assignment of emissions from specific import sources to California companies can create incentives to "reshuffle" purchases. This would involve firms releasing their rights to purchase power from "dirtier" import sources and replacing the power with new contracts from "clean" sources. If the relinquished dirty capacity finds new buyers outside of California, there is no net benefit to the environment. The carbon formerly "produced" by California electricity consumption simply gets shifted on paper to other unregulated regions.

Without specific mechanisms in place to combat reshuffling, it appears to be a significant concern. This is because of the large amount of low-carbon electricity already produced in the western electricity market (see Table 1).[11] With sufficient reshuffling of supplies, it is possible to meet California demand (on paper) from current sources while emitting *no* CO2. Of course this would imply significant increases (on paper) of emissions for electricity consumed elsewhere in the WECC. If those regions are not subject to the same load-based regulation, this would have no cost impact on them.

Table 1: Energy Produced in 2004 by Major Fuel Source and Sub-Region (TWh)

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

[10] It is important to note that the "dirtiest" plant is not fixed in time, during some periods this may be a baseload coal plant, in other periods it may be an inefficient peaker plant. Therefore any standing value for imports will result in some measurement error, even ignoring the incentive problems.

[11] A more detailed assessment of the risks of reshuffling and other related issues can be found in Bushnell, Peterman, and Wolfram "California's Greenhouse Gas Policies: Local Solutions to a Global Problem? CSEM working paper WP-166 (2007).

4.0 Potential Adjustments to Combat Incentive Problems

Several adjustments have been proposed to combat the reshuffling problem. Most solutions involve fixing a default value for imports that can only be changed if the importer switches to a *new* facility, rather than an existing one. The CPUC/CEC report proposes that firms not be allowed to claim new contracts from *existing* sources. This is a positive step that would eliminate the GHG benefits of contracting with existing clean sources. However, if allowed, firms could still choose to abandon contracts from dirty plants and claim the regional average for replacement energy. Actual emissions would remain unchanged in such an event, but on paper, they would appear to be reduced by an amount equal to the difference between the emissions values of the specific plants and the generic import values. As with leakage, this dynamic would free up emission credits and potentially limit the reductions seen in other industries.

An even stronger restriction would fix compliance responsibility to a historical "snapshot" of purchases. The regulation would make the current purchaser (or first-seller) responsible for emissions from that plant in the future regardless of who purchases the output from that plant. For example, LADWP would be responsible for its share of the future emissions of the inter-mountain power plant, from which it has historically purchased power, even if its own power is purchased elsewhere in the future. Such a proposal would, to some extent, decouple the ongoing purchasing decisions of firms from their emissions responsibilities. Instead the emissions responsibilities would be tied to a historic purchase profile.

This backward-looking assignment has the advantage of eliminating the incentives to shuffle future purchases. This is because the regulated firm's responsibility would remain tied to the plants it purchased from in the past. This could also resolve the problems with regards to CAISO market purchases under a load-based cap. This is, again, because responsibility for emissions would not be tied to ongoing purchases, be they imports, self-scheduled, or pool-based purchases.

However, by decoupling ongoing purchasing decisions from emissions responsibilities, such a regulation could also remove much of the leverage California firms have to influence the output of plants located outside of the state. Thus, for example, LADWP would be responsible for the emissions of inter-mountain, but may not be able to do much about those emissions beyond suspending purchases from the plant. Further, a historic assignment of emissions would suffer from some of the same ambiguities that an ongoing assignment suffers from. Many historic purchases were taken from either pool-based markets, and emissions from those purchases would have to utilize some administrative-based average. The use of averages in this context would be fixed, it would not create an ongoing incentive to beat the averages through shifting purchases. Last, there are significant legal questions surrounding a policy that would in-effect assign responsibilities for *future* emissions from a facility to an entity that had purchased from it in the *past*.

This discussion highlights the tension between dealing with incentive problems and measuring emissions accurately. The application rigid values for imports (or pool purchases) can eliminate the incentives to shuffle purchases. However, those rigid values will also, inevitably, be less accurate than a detailed accounting of specific sources.

A related concern is the relative treatment of imported energy and energy generated from California plants. Rules that apply rigid default values to imported energy, but not to domestic power, may prompt legal challenges. Therefore, fixes that would combat the reshuffling problem could, ironically, undue the very legal advantages that made the load-based program attractive in the first place.

Outside of specific elements of the cap-and-trade design, two other factors will largely influence the degree to which incentive problems undermine the spirit of the GHG regulations and the operations of the wholesale electricity market. These factors are the influence of more direct regulations by the CPUC and other institutions and the potential broadening of a California cap-and-trade program to include neighboring states.

The CPUC and California legislature have already imposed several significant policy measures that impact the GHG emissions of the electricity sector. These measures include an aggressive renewable portfolio standard (RPS) that may become even more aggressive. There are also several measures that influence the procurement decisions of both CPUC and non-CPUC jurisdictional utilities, such as carbon "adder" to the costs of dirtier acquisitions and the recent Senate Bill 1368, which restricts the ability of firms to sign long-term contracts with coal-fired facilities. There are also several aggressive energy-efficiency programs.   In sum, these measures may very well reduce emissions in the electricity sector below 1990 levels by themselves. This may leave any cap imposed under AB 32 unbinding, at least in the electricity sector. If other sectors are included, these "slack" emissions credits would be taken up by other industries, reducing the need for reductions there.

These measures also limit the ability of firms to engage in either leakage or contract shuffling to various degrees. In short, most electricity purchased in California is bought by firms under strong regulatory or government control. These firms are unlikely to be able, or even strongly motivated, to shift large amounts of energy to dirty sources in ways that conflict with the spirit of AB 32. However, although most firms are under the influence of various governments, the extent and nature of this influence does differ. Thus a reliance on regulatory backstops to offset obvious incentive problems with the cap-and-trade system could leave certain firms better able to skirt the regulations than others. This in turn could create perverse incentives for direct access, community choice aggregation, or other retail initiatives.

The extension of cap-and-trade to other western states could alleviate these problems without the need for additional regulatory steps. It is important to note that the impacts of such a geographic extension are not the same for all possible cap-and-trade designs. Recall that the load-based program posed difficulties for local unspecified purchases as well as imports, while the difficulties with source-based and first-seller are largely limited to imports. The expansion of cap-and-trade will increase the percentage of purchases that are "local," from the perspective of the carbon regulations, and reduce the amount of imports. In particular, leakage and contract shuffling become less severe as more states are brought into the fold. There are simply less plants to shift purchases to that are outside the GHG regulatory system. The perverse incentives provided by a load-based cap, however, could be magnified by an expansion of the program to other states. In particular, the bias against pool-based markets would be extended to more regions.

5.0 Summary

California policy makers are determined to combat greenhouse gas emissions on many fronts, from low-carbon fuel standards for transportation to energy-efficiency programs for electricity consumers. A cap-and-trade system would overlay all of these programs, and yet it is possible that it may not be very binding given the net effect of all the other initiatives.

Any cap-and-trade program that is adopted in California faces the challenge of implementing regulations over a geographic jurisdiction that is smaller than the markets California firms operate in. This is particularly true for the electricity industry, where California is highly integrated with other markets in the western grid. Each of the three major options, source-based, load-based and first-seller, are likely to create at least some perverse incentives for trading and investment in the electricity market. These incentives can be offset, at least partially by policy design, regulatory oversight.

The largest challenge, and source of incentive problems, is the assignment of emissions from sources outside of California to firms who would be regulated inside of California. The load-based approach appears to create the most potential incentive problems in this regard, particularly for the CAISO markets. It also may be the approach most able to withstand legal challenges to including imports within a cap-and-trade system. The first-seller approach limits the distortions created by assignment to imports, and thereby avoids these problems for plants within the state.

The integrity of any cap and trade regime applied to the electricity industry will ultimately rely upon the expansion of the program to include other regions. Therefore an important consideration is the ability of a California scheme to integrate with broader regional initiatives. Here it is notable that source-based programs have been the dominant paradigm for cap-and-trade programs in other regions and for other pollutants. As the regional scope of the program grows, concerns about leakage and contract shuffling will decline. The problems with assigning emissions from specific plants to load-serving entities will remain, however, and most likely grow more severe. Even if the load-based program represents the best option for a unilateral California regulation in the short-run, a debatable proposition, it could therefore handicap the States efforts to combat GHG emissions in the long-run.