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Comments on Type and Point of Regulation for Greenhouse Gases – CPUC Rulemaking 06-04-009 and CEC Docket 07-OIIP-01

Andy Van Horn and Ed Remedios

California Public Utilities Commission
Dockets Office, Room 2001
505 Van Ness Avenue
San Francisco, CA 94102

California Energy Commission
MS-4 Docket Office
Re: Docket 07-OIIP-01
1516 Ninth Street
Sacramento, CA 95814-5512

These comments and three attached papers present recommendations regarding the market design for reducing greenhouse gases (GHG) in California. The authors of these three papers have decades of experience as participants in and evaluators of the energy and emissions markets that will be affected by the regulatory framework to be adopted by the State of California. Importantly, the conclusions expressed here regarding the appropriate regulatory framework for California and the West differ significantly from the market design currently preferred by the California Public Utilities Commission (CPUC).

The first paper, given in Attachment A, is "A Comparison of Three Cap and Trade Market Designs and Incentives for New Technologies to Reduce Greenhouse Gases," by the authors of these comments.[1] Our paper addresses fundamental market design issues and compares source-based, load-based, and first-seller/deliverer market designs for regulating greenhouse gases (GHG). It also compares incentives for the development and deployment of new technologies under each of the three potential market designs. These comparisons show that new technologies would realize higher values under source-based and first-seller/deliverer market designs than under a load-based system. The comparisons also show that a load-based regulatory system would be more complex, costly and inaccurate than either a source-based or a first-seller system.

A further conclusion of this analysis is that the adoption of an integrated, source-based market design covering many sources in many states will provide the greatest

[1] Van Horn, Andy and Ed Remedios. A Comparison of Three Cap and Trade Market Designs and Incentives for New Technologies to Reduce Greenhouse Gases, VHC Working Paper 2007-11-01. November 16, 2007. www.vhcenergy.com

opportunities for the innovation and advancement of new technologies, as well as for the success of a regulated cap and trade market for greenhouse gases.

The second paper, Attachment B, "State Efforts to Cap the Commons: Regulating Sources or Consumers?," by Dallas Burtraw, Resources for the Future, directly addresses the question "where to locate the point of compliance in the electricity sector—that is, where in the supply chain linking fuel suppliers to generators to the transmission system to retail load-serving entities should the obligation for measurement and compliance be placed." It concludes that the first-seller approach would be best for California. It also states that, "The alternative 'load-based approach' has a running head start in the policy process but would undermine an economy-wide market-based emissions trading program."[2]

Finally, the third paper, Attachment C, reaches conclusions similar to the first two papers. This paper, Opinion on "Load-Based and Source-Based Trading of Carbon Dioxide in California," is by the members of the California ISO's Market Surveillance Committee, Frank A. Wolak, James Bushnell, and Benjamin F. Hobbs. It strongly recommends a source-based regulatory approach for California. The paper emphasizes that "a load-based cap-and-trade system, is clearly and substantially inferior to the other options." [i.e., Source-based and hybrid approaches.] It also states that, "We believe that the load- and source-based approaches are similar in some respects, but that the load-based approach is distinctly inferior in others. In particular, we argue that the two systems are essentially the same on the issues of determining the GHG content of power imports and incentives for investments in energy efficiency and renewable energy. However, in terms of administrative complexity, adverse impacts on the efficiency and costs of dispatching generation units to meet load in California energy and ancillary services markets, and compatibility with likely federal GHG legislation, a load-based system has serious disadvantages compared to any of the other options. Contrary to some claims, we believe that resulting cost of energy to consumers would likely be *higher* under a load-based cap."[3]

In addition to the thorough discussions of source-based, load-based and first-seller regulatory frameworks in Attachments A, B and C, we offer the following observations regarding the point of regulation.

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[2] Burtraw, Dallas. State Efforts to Cap the Commons: Regulating Sources or Consumers? Dallas. Resources for the Future. November 9, 2007.

[3] Wolak, Frank A., Bushnell, James and Benjamin F. Hobbs, Market Surveillance Committee of the California ISO. Opinion on "Load-Based and Source-Based Trading of Carbon Dioxide in California." November 27, 2007. pp. 2-3.

Why California's Future Regulatory Framework for Greenhouse Gases Should Focus on Emission *Sources*, Instead of Regulated Load Serving Entities (LSEs)

1) *Sources* determine their own emission rates.
2) *Sources* buy and install improved technologies.
3) *Sources* can more accurately measure and verify their own emissions and reductions.
4) *Sources* can properly internalize the costs of emission reductions or allowance purchases by passing on these costs in prices.
    a. Electricity market operating decisions will reflect emissions allowance (EA) prices in a source-based market, but not in a load-based market.
    b. Gaming and other evasive practices, such as contract shuffling, will be reduced.
5) Responsibility for emissions compliance should lie with the owner/operator of a S*ource*, not the buyer of the product. (Under a load-based approach compliance obligations will be placed on the LSE buyer, not the seller.)
6) Compliance and emissions trading is now successfully conducted in S*ource-Based* markets with strengths and weaknesses that are understood.
7) The *First Seller/Deliverer* approach is a *Source-Based* approach for in-state electric power generators and becomes more like a S*ource-based* approach as the geographic scale of the regulated market grows.
8) There must be *Source-Based* compliance protocols and measurement of emissions by *Sources*, even if a load-Based market design is adopted. The near to real time measurement and allocation of emissions to downstream buyers will be more difficult than under a *Source-based* system.
9) Clear & stable price signals from emission allowances in a *Source-based* market will provide better incentives to develop improved technologies and to comply at least-cost by allowance trading.
    a. Fossil-fired resources will internalize allowance costs.
    b. Non-emitting Renewables, which require long-term contracts, will gain an additional cost advantage by not having to acquire allowances. (The amount of renewables that will be developed will be determined by the cap, the rate of decline of the cap and the cost of allowances <u>or</u> by mandates like a Renewables Portfolio Standard.)
10) As a result of tracking inaccuracies and "adverse selection" for generators, the *Environmental Integrity* of any *Load-Based* market will be compromised.
    a. Low emitters will seek long-term contracts that recognize their low emission rates.

b. High emitters will seek the administratively determined "imputed" average emission rates.

c. Emission reductions will be more difficult to track and verify for out-of-state entities.

11) All GHG allowances in a market where a sizable percentage of allowances lack *Environmental Integrity* may be discounted in price or may not be fungible as "offsets" in other allowance markets, such as the Regional Greenhouse Gas Initiative (RGGI) and the European Union Emissions Trading Scheme (EU ETS).

12) The closer the point of regulation is to the *Source* of emissions, the better the enforcement.

13) The closer the point of regulation is to the *Source* of emissions, the greater the incentives for technological improvements and innovation.

14) *Source-based* market designs can be scaled-up to encompass larger geographic areas and a larger number of *Sources*. (The load-based approach isn't easily expandable to other states and isn't compatible with other GHG markets, which are *source-based*.)

15) A *Source-based* market will be easier and faster to implement, and less costly to operate and enforce than a *load-based* market.

Why A Load-based GHG Allowance Approach Will Not Work Well

1) **Lack of environmental integrity.** All successful emissions allowance programs must satisfy the following minimum criteria for *environmental integrity,* in order for allowances to be counted for compliance and to represent real reductions: Emissions and emission reductions must be "*real, measurable, verifiable, and enforceable.*" California's proposed load-based system allowances would fail these requirements.
2) **Inherent inaccuracies in accounting for emissions would preclude effective verification and trading.** Emission allowances associated with power imported into California would rely on imputed or administratively estimated and allocated emissions. These inaccuracies may render all CA allowances not tradable or cause all CA allowances to be traded only at discounted prices. Depending on imputed emissions' rates, a ton for compliance may be more or less than a ton of actual emissions. True-up and validation over all sources and all LSEs on an hourly basis would be cumbersome and more costly than the quarterly Continuous Emissions Monitoring Systems (CEMs) reporting now required.
3) **Avoidance of transactions with California's load-based buyers by out-of-state generators/emissions sources selling into unregulated markets.** New Mexico, Montana, Utah and states east of the Mississippi must participate in a GHG market, in order to achieve significant GHG reductions. The ability to sell and contract for power elsewhere in the

West, instead of selling into California, could lead to power shortages in California in low hydro years, similar to those that occurred during 2000-2001.

4) **Inability of Load Serving Entities (LSEs), like Pacific Gas and Electric Company (PG&E), to control emissions from sources procured by the California Independent System Operator (CA ISO).**
5) **Inability of LSEs to dispatch resources under the CA ISO's Market Redesign and Technology Update (MRTU) to be implemented in 2008.** Coal-fired power plants will make cheaper bids and will continue to be dispatched based on bids, not emissions.
6) **Misalignment of market incentives for developers and vendors of technologies.** Although they hold emission allowances, LSEs are not the most likely buyers of new technologies to reduce emissions
7) **Disruption of current electric product markets and contracting practices**, where sources of power are frequently unspecified. LSEs or market intermediaries will have to allocate emissions from power coming from multiple plants to multiple customers. The need for future allowances will be hard for some LSEs and first sellers/deliverers to predict. True-up among financial contracts and different electricity markets (e.g., day-ahead, hour-ahead and real time) will be unnecessarily complex and costly.
8) **Need for many sources to participate in a dual, hybrid regulatory structure,** where both load-based and source-based regimes must be satisfied.
9) **Inability of LSE's to send a consistent market-clearing price signal simultaneously to electricity consumers and to GHG emitters.** In contrast to a source-based system, allowance costs will not be properly internalized under a load-based system. Instead of market-generated signals, Public Utilities Commissions (PUCs) will generate indirect price signals to downstream electric consumers via rates, while LSEs try to send different price signals to upstream generators, depending on the LSE's portfolio mix and market purchases.
10) **Incompatibility of a California/Oregon load-based approach with the Regional Greenhouse Gases Initiative (RGGI) in the U.S. Northeast and the European Union Emissions Trading Scheme (EU ETS) in Europe and with potential U.S. national GHG regulations, which are all source-based.**
11) **Lack of scalability.** The sheer number of transactions and difficulties of verification and enforcement grow exponentially as the number of regulated LSEs and sources grows in a *load-based* market, such as when the geographic boundaries of the program expand beyond California. Hence, a load-based market design should not be widely adopted. In contrast, a source-based market can easily encompass additional sources.
12) **High transaction costs.** The tracking, verification and administrative costs will be higher in a load-based system than in a source-based system.

13) **Lack of sustainability.** The complexity of a load-based system and its high administrative and transaction costs will make such a system unsustainable.

14) **Perverse incentives and gaming by market participants.** Perverse incentives for both higher emitting and low emitting sources would be created. *Contract shuffling* and other actions to game transactions would exist under a load-based approach. Such perverse incentives constitute "adverse selection."

15) **Political posturing by different states claiming low-emitting resources for themselves.** *Contract squabbling* by political entities would not be an issue under a source-based market design.

16) **Wasted time, higher costs and diverted resources from adopting a load-based system, and then making a more difficult transition to a national source-based system.** The transition from a California or Western load-based system to a U.S. source-based system will be difficult and could possibly delay implementation of a working nationwide system. Until the U.S. develops a national plan and commercializes improved technologies, India, China and other large emitting countries will continue to expand their GHG emissions by employing today's dirtier technologies.

For all the above reasons, as well as the supporting analyses provided in Attachments A, B and C, California regulators should select a market design that could actually behave like a market, i.e., a tried-and-tested source-based design, instead of a load-based design that can not send clear market signals.[4] Finally, there is no doubt that making the transition to a national source-based market from either a source-based or first-seller market design will be faster and less costly than undoing a complex and unwieldy load-based approach.[5]

Respectfully submitted,

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[4] Van Horn, Andy and Ed Remedios. A Comparison of Three Cap and Trade Market Designs and Incentives for New Technologies to Reduce Greenhouse Gases, VHC Working Paper 2007-11-01. November 16, 2007. www.vhcenergy.

[5] The experience of Great Britain demonstrated the problems in making the transition from a load-based approach to the source-based European Union Emissions Trading Scheme.

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Attachment A

Working Paper
2007-11-01

A Comparison of Three Cap and Trade Market Designs and Incentives for New Technologies to Reduce Greenhouse Gases

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ABSTRACT

In 2008, California and other states are planning to adopt regulatory frameworks to govern their future emissions of greenhouse gases. This paper compares three potential cap and trade market designs:

1) source-based,
2) load-based, and
3) first-seller/deliverer,

as they would be applied to the electric power sector. To distinguish among these candidate designs, the paper considers how well each cap and trade design would meet several basic objectives of environmental markets, including the capability to provide the incentives needed for the development, deployment and utilization of new and innovative technologies. An array of improved technologies will be essential to achieve significant reductions in the emissions of global greenhouse gases. Hence, the paper also addresses the question: ***Which cap and trade market design will provide the best incentives to develop and utilize advanced technologies?***

First, the basic objectives of a cap and trade market are identified. Then, the capabilities to satisfy each objective are compared for the three potential cap and trade designs. These comparisons show that new technologies would realize higher values under source-based and first-seller/deliverer market designs than under a load-based system. The comparisons also show that a load-based regulatory system would be more complex, costly and inaccurate than either a source-based or a first-seller system. A further conclusion of this analysis is that the adoption of an integrated, source-based market design covering many sources in many states will provide the greatest opportunities for the innovation and advancement of new technologies, as well as for the success of a regulated cap and trade market for greenhouse gases.

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1. INTRODUCTION AND SUMMARY

In 2008, California and other states are planning to make path breaking decisions regarding the regulatory frameworks that are intended to govern their future emissions of greenhouse gases (GHG). To make these decisions, it is important to consider how well each potential framework will meet several basic objectives of environmental markets, including the capability of each market design to provide incentives for the development, adoption and utilization of new and innovative technologies. The three potential cap and trade market designs examined in this paper are:

1) source-based,
2) load-based, and
3) first-seller/deliverer,

as they would apply to the electric power sector.

In addition to evaluating how well each potential design will meet the basic objectives of an environmental market, this paper also addresses the question: *Which cap and trade market design will provide the best incentives to develop and utilize advanced technologies?* First, we identify the basic objectives of a cap and trade market for GHG. Then, we compare the capability of each of the three cap and trade designs to meet these objectives. A table on pages 5 and 6 briefly summarizes these comparisons, while the text following the table discusses each objective and market design at greater length. Finally, in the Conclusions section, we give our recommendations, which are also summarized at the end of this section.[1]

In a source-based market electric generators that burn fossil fuels will be the affected sources or, in other words, the point of regulation or, in other words, the point of compliance. An affected source must comply with GHG regulations by acquiring and surrendering emissions allowances (EAs) for each ton of emissions.[2] As the number of allowances issued declines over time, so will emissions. In a load-based regulatory approach the regulated entities that must comply are the Load Serving Entities (LSEs). LSEs are companies that generate or buy and then deliver electricity to their customers, i.e., the load. In a load-based regulatory scheme, each LSE must acquire and surrender sufficient EAs to cover the GHG content of all the electric power it delivers to end-users. In most cases, the LSEs are established electric utilities regulated by their respective state public utility commissions (PUCs). In a first-seller/deliverer market, the regulated first-seller/deliverer is the entity that first sells or delivers electric power into the state where that power is subsequently sold to end-users by an LSE. For example, if a fossil-fired electric generator is located within California and sells its power to Southern California Edison (SCE), the emissions source will be the first-seller. If, however, a generator is located outside of California, the first-seller of the power that is ultimately delivered to SCE might be either the generator/emissions source or an intermediary that has purchased power from that generator for resale, such as a power marketer or broker, or SCE itself, which may buy and import the power. Each of these three market designs would require compliance by a different set of entities, and each will impose different

[1] The authors wish to thank Dallas Burtraw, Resources for the Future, Mike Katz and Kris Chase, VHC, for insightful comments on a draft of this paper. Of course, the views and opinions expressed here are those of the authors and do not necessarily state or reflect the views of anyone else. Any errors are the authors' own.
[2] In the electric utility sector the cap will most likely apply to carbon dioxide (CO_2) emissions.

requirements on the measurement and verification of the GHG emissions content of the electric power consumed within California.

The basic principles of economics, as well as experience with cap and trade markets in the U.S., U.K. and Europe, tell us that these three market designs are likely to have significantly different effects on the development and deployment of new and cleaner technologies.[3] In general, investments in improved and innovative technologies will be most likely to occur if the costs of GHG are clearly valued and internalized in the prices of the outputs or services provided by these technologies. Technologies suitable for global deployment will have greater opportunities for funding, demonstration and ultimate success than technologies developed to meet only localized market needs. Hence, regional market design should encourage access to global markets by allowing verified "offset" projects that utilize new technologies and will move them more rapidly along their developmental learning curves.[4]

Competitive markets should have many buyers and many sellers.[5] It is evident that source-based and first-seller/deliverer markets would involve more buyers and sellers than a load-based market, where the number of regulated electric Load Serving Entities (LSEs) is smaller than the number of GHG sources and first-sellers that would be regulated under the other two alternatives. The smaller number of regulated LSEs in a load-based market could lessen the volume and frequency of emission allowance (EA) trades, as well as the degree of competition, giving rise to market power concerns. Moreover, in a load-based market the need to use imputed GHG emissions to characterize many electric power transactions that originate out-of-state will mask market signals and give rise to gaming opportunities for higher emitting generators. Imputed emission rates will cause lower-emitting electric generators to prefer bilateral contracts with LSEs, in order to realize the value of their lower GHG emissions.[6] Overall, the use of imputed emission rates will lessen the environmental integrity of all allowances in a load-based market.[7] As will be described below, these

[3] See, for example, the presentation by a former U.K. regulator who helped make the transition between the U.K.'s load-based GHG market and the European Union's Emissions Trading Scheme: Olivia Hartridge, Greenhouse Gas Cap and Trade Systems: Symposium on Linking. Presentation to the California Public Utilities Commission, April 19, 2007.

[4] Offsets are real, measurable, verifiable, additional and enforceable GHG reductions at entities that are not required to make reductions by a regulatory system. Some have argued that by limiting the reductions that can be counted as verified "offsets," local technological innovation will be encouraged. This is not the most likely way to encourage innovation, because the need for global GHG reductions will create far larger opportunities to sell a wider variety of improved technologies than local or regional markets can provide. In most cases, first movers into offset markets, whether domestic or foreign, can gain a competitive advantage and progress more rapidly along the technological learning curve at lower costs and with greater profit opportunities than can be achieved in localized markets by themselves.

[5] The number of buyers and sellers can be increased by allowing "offsets" and enabling allowance trading between regional markets, such as the European Union's Emissions Trading Scheme and the U.S. Regional Greenhouse Gas Initiative states. Interregional emissions trading can keep regional costs down, while enabling the development of new and improved technologies.

[6] Imputed emission rates are administratively determined rates, rather than actual measured rates. They are expected to be calculated average rates assigned in advance to transactions between a generating region, e.g. the Southwest, and a buying region, e.g. California.

[7] The masking of GHG costs in a load-based market and the perverse incentives given to emitters are referred to as *adverse selection,* which is an undesirable characteristic for any market. This characteristic arises partly from the use of imputed emission rates for imported power, and it would significantly reduce the environmental integrity of load-based emissions allowances for GHG.

characteristics and other features of the three market designs will also lead to different effects on technology investment, operating and purchasing decisions.

The strengths and shortcomings of source-based markets have been tested in practice, while there are many shortcomings of the load-based approach that will make this market design more costly and not scalable up to multi-state or regional coverage levels. The first-seller/deliverer approach is a hybrid of these two market designs and is expected to have impacts falling in between the effects expected for the other two approaches.

In summary, the comparisons presented below show that a load-based system would be more complex, costly and inaccurate than either a source-based or a first-seller market design.[8] As a result, clearer market signals to buyers and sellers and increased incentives for technological innovation are more likely under the source-based and first-seller/deliverer market designs. Therefore, to comply with California's Assembly Bill No. 32 (AB 32) passed in 2006, we recommend that California and other western states adopt an integrated, source-based cap and trade system with broad enough geographic coverage to include most of the power sources now serving California and other western LSEs. As a second choice, which would incur unnecessary costs prior to the transition to a national cap and trade system, we recommend that California and other western states adopt a first-seller/deliverer market design with provisions for replacing it with a national source-based system, as soon as possible.

2. OBJECTIVES FOR GHG CAP AND TRADE MARKET DESIGN

The primary goal of a GHG cap and trade market is to:

- Reduce regional GHG emissions to levels set by emission tonnage caps in an efficient and cost-effective manner.

GHG reductions will occur, if a market design properly internalizes the costs of GHG emissions in the prices of goods and services, and if there are appropriate penalties for non-compliance. In order to internalize the costs of complying with emissions regulations, entities must pass along their compliance costs, so that all market participants receive proper price signals. Then emitters, intermediaries and consumers can select the most economically efficient products, including environmental costs. In turn, cap and trade provides emitters with an effective market mechanism to reduce their own GHG compliance costs by trading EAs when it is economic to do so.

Emissions will be reduced as the number of allowances declines over time. Since different parties will be able to control or avoid emissions at different costs, there will be opportunities for allowance trading. The success of the market depends on having many buyers and many sellers, such that a competitive supply/demand balance creates a market clearing price signal. For those sectors with similar costs of control or where the burdens of regulation might be prohibitive, a pre-combustion or upstream point of regulation may be preferable, such as imposing an emissions tax on gasoline. In successful cap and trade markets to date, the emitter bears the burden of compliance. By reducing emissions to meet a cap regulated by EAs, products can become more cost-competitive <u>and</u> environmentally friendly.

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[8] Trying to institute a regional load-based cap and trade system and failing to achieve fundamental market objectives would set back public confidence in any carbon emissions reduction scheme.

A cap and trade market will internalize the costs of GHG and operate efficiently, if it satisfies the following objectives:

- Initiates *clear market price signals* for GHG allowances that are internalized in product prices,
- Creates *uniform and stable GHG allowance prices* across market sectors and diverse sources with different compliance costs,
- Maintains the *verified environmental integrity* of allowances, so that trading can occur among many market participants across geographic and political boundaries,[9]
- Keeps *monitoring, administration and transaction costs low*,[10]
- Minimizes the *overall costs* of compliance,
- Promotes *research, development and demonstration (RD&D) of lower emitting technologies*,[11]
- Provides incentives to *purchase and use lower emitting technologies,*
- Enhances *environmental justice,*
- Keeps the *basic rules and functions simple and enforceable,*
- Avoids *unintended consequences,*
- Enables the timely *transition to a geographically larger regional or national system* for emissions reduction and is *scalable in size*,[12] and in California,
- *Satisfies* requirements under Assembly Bill No. 32 (*AB 32*).

3. COMPARISON OF THREE CAP AND TRADE MARKET DESIGNS FOR EACH ENVIRONMENTAL MARKET OBJECTIVE

The table below summarizes the capability of each market design to achieve the objectives listed above, while the sections that follow discuss each objective in more detail.

[9] To achieve and maintain "environmental integrity" GHG allowances must be tied to accurately measured, verifiable and enforceable tons of GHG emissions. The environmental integrity, equity, efficiency and timing of allowance allocations, trading procedures and compliance rules, such as banking or borrowing, are key design elements that will determine how well this future market functions.

[10] There are no essentially no mandated transaction costs for GHG emissions in those locations where it is not currently regulated or where there is not voluntary compliance. Mandated transaction costs that are too high will inhibit the utilization of a cap and trade system.

[11] Meaningful global GHG reductions will not be achievable without developing new, lower-emitting technologies and making behavioral changes in the ways in which we use existing technologies. Because of the scale of energy sector technologies that will be needed and market failures that inhibit RD&D, other incentives will be needed in addition to a market design that is favorable for recovering costs and operating at a profit. Regulatory uncertainty can significantly inhibit investment in both existing and developing technologies, regardless of future market designs.

[12] While state-by-state regulations are an important start, achieving the ultimate goal of global GHG reductions requires a U.S. national regulatory system that can reduce emissions at least cost. However, at the same time as a cap and trade market creates the demand for improved technologies to reduce GHG, additional incentives will be needed to create them because of the uncertainty of future GHG allowance prices and R&D market failures.

Comparison of Greenhouse Gas Market Designs – Source-based, Load-based and First-Seller/Deliverer

Objective: / Market Design:	Initiates clear market price signals for greenhouse gases (GHG)	Creates a uniform and stable GHG allowance price	Maintains the verified environmental integrity of emissions allowances (EAs)	Promotes research, development and demonstration (RD&D)	Provides incentives to purchase and use lower emitting technologies	Keeps monitoring, administration, and transaction costs low
Source-based	Changes supply curve: GHG EA costs internalized in kWh prices, allowing pass through of costs to all buyers, such as Load Serving Entities (LSEs). Markets can be linked globally.	Buyers will see internalized GHG price signals from those emitters covered by a cap. A uniform market clearing price will be created for EAs, and inter-regional trades will occur.	Source-based monitoring, tracking system and verification protocols provide ongoing integrity for EAs and certified emission reductions (CERs) at individual sources.	Sources must acquire sufficient GHG allowances to cover emissions and over time must find ways to reduce GHG. Regulated sources may fund some R&D, but will primarily own/buy new technologies.	Reducing costs of compliance with declining EA allocations over time provides incentives to develop, buy and operate improved lower-emitting technologies.	Systems and procedures are proven & tested. These costs should be reasonably low for sources that are already regulated for other emissions.
Load-based	Changes demand curve only from regulated buyers. Price signals to ratepayers and EA price signals from LSEs to power providers will be different.	Cap applies only to regulated LSEs – not to sources. Unregulated emit-ters might evade the cap by selling to unregulated LSEs elsewhere in the western region.	Imputed GHG from out-of-state (OOS) & system sources will lack environmental integrity. All EAs could be price discounted or not tradable OOS.	LSEs are not usually the direct buyers of improved GHG emitting technologies. Less incentive to fund R&D, since EA costs passed thru to ratepayers.	Unless they own emission sources, regulated LSEs are not likely purchasers of low emitting, supply-side technologies, but will buy from cleaner sources.	Very high administrative and tracking costs unless emissions from out-of-state are imputed. Cross-checks needed. Not fully MRTU compatible.
First-Seller/ Deliverer	First-deliverer sends market price signal to LSEs and to emitters. First-deliverer may be an emitter or a market intermediary.	In-state sources & first-deliverers would create a uniform EA price, but must compete with OOS power sources selling to buyers outside of capped region.	Hybrid compliance market. In-state EAs verifiable; out-of-state not tracked as accurately, resulting in dis-counted prices for all CA allowances.	If first-deliverer is an emitter, then EAs give some incentive to fund R&D and to buy innovative & new technologies. If it is a marketer/reseller, probably not.	If first-deliverer is an emitter, then declining EAs will provide some incentive. LSEs & others will prefer to buy power from cleaner plants.	High costs, since brokers will have difficulty forecast-ing their EA needs and tracking & allocating the GHG content of their power imports and resales.

Comparison of Greenhouse Gas Market Designs – Source-based, Load-based and First-Seller/Deliverer (Continued)

Objective: / Market Design:	Minimizes overall costs of compliance	Enhances Environmental Justice (EJ)	Keeps basic rules & functions simple and enforceable	Avoids unintended consequences	Enables timely transition to a regional or national cap and trade system & is scalable in size	Satisfies requirements under California Assembly Bill: AB 32
Source-based	Provides greatest source diversity and EA trading opportunities to reduce overall compliance costs. Most easily linked to & consistent with RGGI* and EU ETS* designs.	Provides some incentive to develop new technologies & to replace existing higher emitting urban plants. Thus, should be EJ preference, but is not now.	Scalable up in size. Source specific rules and incentives to comply are the simplest. GHG emitted is easier to measure, track, verify and enforce.	Will internalize GHG costs most efficiently, leading to fewer market surprises and fewer "gaming" opportunities and better compliance with declining emissions caps.	Used for today's successful SO_2, NOx & EU ETS GHG cap and trade programs. Will likely be the U.S. national system. Transition would be easiest. Global trading also viable.	Yes, but only if most states in Western Electric Coordinating Council (WECC) selling power to CA adopt source-based reporting standards and a GHG cap.
Load-based	Highest in costs due to fewer LSEs, fewer verified EAs and fewer trades plus high admin costs. Some market power concerns. Not easily linked to RGGI or EU ETS or nation.	Could lead to earlier replace-ment of urban plants than costly command & control regulation. But existing plants will remain longer than under source-based cap & trade design.	Not scalable up in size to WECC or nation, due to exponential growth in # of transactions as more LSEs are included. Imputed GHG not verifiable – *a ton may not be a ton.*	Will encourage "contract shuffling" and "contract squabbling" and discourage power imports to CA utilities, possibly causing higher CA and WECC prices, as in 2000-2001.	Not scalable up in size to cover a multi-state region. Not easily transferable to a source-based system. Wasted time, effort and money, when a national system is adopted.	Yes, but only on an imputed index basis, due to need to impute GHG emissions from imported power to each state, which can not be tracked accurately or cross-verified.
First-Seller/ Deliverer	Will be higher in cost than a source-based system, but lower in cost than a load-based design.	All three cap and trade market designs are more likely to replace urban plants than more costly command & control GHG regs.	Similar in many respects to a source-based design but with difficulties for out-of-state first-deliverers selling imported power.	Marketers and out-of-state power plants may choose to sell to buyers in unregulated states, causing higher CA prices.	First-deliverer compliance systems and procedures will be more easily transferable than would a load-based system.	Yes, on an index basis, but only if all first-sellers/ deliverers can accurately verify & allocate GHG emissions to each transaction.

*RGGI = Regional Greenhouse Gas Initiative, states in the U.S. northeast starting a source-based GHG market in 2009. EU ETS = European Union Emissions Trading Scheme

Clear Market Price Signals

A multitude of decisions must be made by investors to create and commercialize new technologies and by consumers to adopt and bring them into widespread use. In the best case, emission regulations should encourage the adoption of better technologies, and, at worst, should not impede their adoption by masking the value of lower emitting technologies.

In any competitive market, price signals are the basic driving forces that influence investment and operating decisions. In a cap and trade market "…consistent and stable price signals will determine whether investors make long-term investments. Proper implementation and execution of a cap-and-trade system will send such price signals. Additionally, EAs need to be scarce enough to limit supply and warrant a price that is significant enough to encourage investments. Minimizing the price volatility of EAs will also encourage long-term investments."[13, 14]

<u>Source-based market design</u>

In this established market design, regulated emission sources are the entities that must comply with emission caps and, thus, affect market price signals by either buying or selling or banking allowances. GHG sources must comply by acquiring and surrendering the number of allowances needed to cover their emissions during a designated compliance period, e.g., over one year. Each source faces marginal compliance costs that equal its own marginal costs of reducing a ton of GHG <u>or</u> the price of purchasing a GHG EA in the allowance market, whichever is less.[15]

The source-based design is the most straightforward and provides the clearest, most transparent and direct market signals.[16] In a source-based system allowance costs originate at the emissions source, i.e., the electric generator, and will be passed along to wholesale buyers of electricity, such as LSEs. In turn, allowance costs embedded in the price of purchased power will be paid for by the LSE's customers in their retail electric bills. Thus, a source-based market signal for allowance prices will be internalized in the price of

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[13] Southern California Edison Company, <u>Response Of Southern California Edison Company (U 338-E) To Administrative Law Judge's Comments And Legal Briefs On Market Advisory Committee Report</u>. CPUC Rulemaking 06-04-009. August 6, 2007. p.16.

[14] Cap and trade markets have exhibited price uncertainty and volatility. Both are dependent on the perceived supply/demand balance over time and the liquidity of vintaged EAs. In the future, maintaining stable EA prices will require certainty about the caps, as well as the implementation of new technologies to reduce emissions and, hence, to reduce the demand for EAs as the supply of EAs declines over time.

[15] Even if allowances are awarded at no cost to regulated sources, the value or opportunity cost of an allowance of a particular vintage equals the market price of that vintage allowance at any given time.

[16] If the cost of producing and delivering electricity from an individual generator is sufficiently below the delivered, market-clearing wholesale price for electricity to enable all the generator's GHG compliance costs, including allowances, to be included in a generator's sales price, GHG costs can be internalized and will be paid for by the LSE when it purchases wholesale power from the generator.

electricity and will be reflected in the purchase decisions of buyers. As discussed in the next section this is not the case in a load-based market.[17]

A source-based framework is the market design applied in successful emissions markets to date, such as the U.S. markets for sulfur dioxide (SO_2) and nitrogen oxides (NOx) and the European Union Emissions Trading Scheme (EU ETS) for GHG. A source-based cap and trade market works best for large geographic areas encompassing many sources. For example, the Western Electricity Coordinating Council (WECC) would be an appropriate region for implementing a viable electric sector GHG market in the western U.S. When the environmental integrity of emissions from individual sources can be tracked and verified, it is likely that trading will also be allowed between sources and other market participants located in different regional allowance markets at prices determined by the market participants conducting allowance trades.

Load-based market design

This market design was proposed, because the electricity purchases of investor-owned electric utilities (IOUs), which are the predominant Load-Serving Entities (LSEs), are regulated by state public utility commissions (PUCs). If it is authorized to do so by state law, a state PUC can create an allowance system, issue a limited number of allowances and require its regulated LSEs to surrender allowances associated with the GHG content of their power purchases and generation. In this market design LSEs, not emissions sources, are the originators of price signals.[18] Since power generators do not need to acquire any allowances, generators will not embed allowance prices in their power sales prices. However, the combined market prices of power and allowances to the LSE will influence the upstream busbar prices at which generators will be willing and able to sell power. To the extent that GHG allowance costs are also passed through in an LSE's retail electricity rates, a different downstream price signal determined by each PUC's regulatory rate design will reach electricity consumers.

Power plants in the WECC can sell to many potential LSEs, and market brokers and intermediaries can buy from many power plants and sell to multiple LSEs, often simultaneously. Hence, the GHG price signal sent from individual regulated LSEs to electric generators that are not under contract may be partially or fully *avoided* by those generators selling to unregulated LSEs and to market brokers. Unlike a source-based

[17] To the extent that the delivered, market clearing price of electricity allows each generator to recover its GHG allowance costs, wholesale prices will internalize the costs of GHG. This is straightforward for a source-based market, since generators are the point of compliance and will bear the costs of compliance. In a load-based market, the point of compliance is the LSE, so the costs of allowances will not be embedded in the wholesale price of electricity.

[18] Determining the GHG allowance price signal for each LSE's portfolio of power purchases at any given time will not be an easy task in a load-based market, which will have the potential to encourage gaming and to conflict with dispatching practices under the California Independent System Operator's Market Redesign and Technology Upgrade, and under potential rules for assigning imputed (i.e., specified administratively, not measured) emission rates. Each LSE is likely to have a different effective avoided GHG price signal, which can vary hourly or more frequently. As a result, LSE's are likely to adopt a time-averaged effective GHG price for making purchase decisions and scheduling their own generation resources.

market where the allowance price will provide an incentive for all affected GHG emitting generators to reduce their emissions, the LSE's market signal in a load-based market will not provide inframarginal generators with an incentive to reduce their GHG emissions.[19] In addition, today's price responsive practices in power markets, including exchanges and purchases of ancillary services, may have to be artificially modified, in order to reflect the load-based price of allowances.

In California, the dispatch of power plants will be based on new rules expected to go into effect in 2008. The Market Redesign and Technology Upgrade (MRTU) rules approved by FERC require that the California Independent System Operator (CA ISO) dispatches power plants needed for system reliability and load following based on the prices bid by each generator. In a load-based system these bid prices will not include the costs of GHG allowances, so under MRTU the CA ISO will dispatch the least-cost generators without direct regard to GHG allowance prices. LSEs will need to estimate the GHG amounts from ISO dispatched units, in order to develop their resource scheduling and contracting strategies intended to enable them to meet their caps. In a load-based market an LSE's GHG goals may conflict with MRTU requirements, and EA prices will not influence plant operations as they would in a source-based market.

As in the other market designs, the downstream GHG price signal to consumers will be controlled by public utility commissions that devise different rate schedules for specific customer classes. Because the costs of allowances will not be included in the wholesale price of power purchases by LSEs, as they would be in a source-based system, generator dispatch and operating decisions will not fully reflect the costs of allowances. Moreover, according to some proponents of the load-based design, PUCs ought to shield ratepayers from the marginal costs of GHG control.[20] In any event, downstream GHG market signals to consumers from LSEs will be set by regulators, not by market forces. Hence, the GHG price signals actually experienced by retail consumers could be significantly different from the adulterated GHG price signals sent upstream by each LSE to its suppliers.

First-seller/deliverer market design

The first-seller/deliverer approach is a hybrid approach, depending on whether an emissions source is located inside or outside of California. The EA price signal for sources within California will be source-based. For sources outside California, the compliance responsibility lies with the first-deliverer of the power to a California location or entity. If the first-deliverer has only one supply source for a contracted supply delivered to a California entity, then a direct price signal will be transmitted upstream to that electric

[19] This and other characteristics of a load-based market design are also discussed in "Burtraw, Dallas. State Efforts to Cap the Commons: Regulating Sources or Consumers? Resources for the Future. Presented at the Conference of the Association for Public Policy and Management, November 9, 2007. This paper concludes that "the load-based approach is not consistent with market reform and greater competition in the electricity sector." It also warns that "a poorly designed market can lead to poor incentives and poor accountability that can bridge to other sectors and undermine confidence in climate policy." p.12 and p.17.

[20] Richard Cowart, presentation to the California Public Utilities Commission (CPUC) Workshop, August 21, 2007.

generator/GHG emitter. However, if the first-deliverer has multiple supply sources at any given time, then the strength and magnitude of the market signal moving upstream will depend on an allocation by the first-deliverer and the timeliness of that market signal. Overall, as the size of a regulated first-seller/deliverer market increases, so that most potential sources are included, allowance prices and electricity market signals should be similar to a source-based system, but with the difficulties of tracking and compliance placed on the first-seller/deliverer. These difficulties will grow in complexity as more generators sell into a first- seller's supply portfolio.

Try to imagine the complexity of keeping track of CO_2 emissions monitored for every hour at each electric generator being followed through the grid and allocated to each LSE taking power from that source during each hour throughout the entire Western grid. The scale of such data gathering and tracking can be compared to the complexity of each source filling out a quarterly report from data collected by its own Continuous Emissions Monitoring System (CEMS) to account for its own hourly emissions. This type of reporting is currently performed by power plants, so that piggybacking CO_2 on top of the NOx, SO_2 and other pollutant reporting already taking place should be relatively easy. Cross-checking and verifying total emissions within a region will also be far easier under a source-based system. Furthermore, the first-seller and the load-based approaches both encourage a mapping or "contract shuffling" of cleaner resources that would be sold to California LSEs at a premium without necessarily changing the dispatch of any resources that are located out-of-state.

In addition, because the first-seller's price signal, as well as a source-based price signal, will internalize the costs of GHG allowances in the wholesale price of power sold to an LSE, current electricity market bidding, operating and dispatch practices can continue, maintaining the market responsive practices that occur today in the operation of the electricity grid.

Uniform and Stable GHG Allowance Prices

Three attractive features of allowance trading are the ability of trades to cross geographic and political boundaries, the ability of caps to set the level of allowable emissions and the ability of regulated entities to achieve lower compliance costs than if emissions taxes or command and control regulations were imposed to achieve the same level of reduction.[21] Provided that GHG allowances are accorded equivalent environmental integrity, the allowance commodity can be traded across geographic and political boundaries at equal or nearly equivalent prices. Even if each GHG allowance market differs in some of its rules, brokers and market intermediaries can establish relative prices for trades, provided that each ton is verified and there is comparability in the relative supply/demand balance of allowances issued in each jurisdiction. GHG markets with broad coverage will have a greater number of market participants and will enable more diverse technologies to participate. In a market that achieves stable allowance prices, it is likely that the incentives

[21] The ability for allowance trades to cross political borders to capture a greater diversity of compliance costs is cited as one reason to prefer a cap and trade approach to applying emission taxes that are politically localized and are also likely to be more expensive in achieving a given level of GHG emissions.

to innovate and develop new technologies will be greater than in a market with volatile and uncertain allowance prices.

Source-based market design

Successful allowance trading markets to date have been source-based. In these markets a *uniform market clearing price* exists and is used as the basis for allowance transactions within the market. The internal allowance price is also a benchmark for the transfer of offset allowances into the market, such as Certified Emission Reductions (CERs) into the EU ETS market. In the case of forward allowance transactions for "offsets" to be provided by future reductions at projects with lower perceived environmental integrity, the allowances to be created by these projects will be traded at a discount to offsets provided by verified reductions with higher environmental integrity.[22] A stable, uniform allowance price for allowances of the same vintage will facilitate trading, increase the volume of allowance trades across market boundaries, and, thus, encourage the implementation of improved technologies to reduce GHG emissions.[23]

Load-based market design

A uniform market price for GHG allowances can be established within a load-based market, but trading among the relatively few LSEs may be limited, creating a thin market with the potential for manipulation and exercise of market power. Moreover, the inaccuracies introduced by imputing emissions is likely to dilute the value of California's GHG allowances, since continuous emission monitors and established authentication methods cannot verify the environmental integrity of some fraction of the out-of-state emissions.[24] Compliance with a load-based cap can be achieved by surrendering one allowance for each ton of imputed or measured emissions. However, if a coal-fired power plant's emissions can be counted at the lower imputed emissions rate, the parties to such a transaction will be getting an effective discount on the number of allowances required, thus, lowering the effective price paid for each ton of such GHG emissions without being reflected in the allowance market.

Imputed emission factors for imports could be different between different states at different times, leading to pricing anomalies for a ton of emissions reduction or to gaming opportunities for sources emitting at a higher rate than the imputed rate.[25] In this

[22] For example, in November 2007, vintage 2008 Certified Emission Reduction (CER) credits from Clean Development Mechanism (CDM) projects trade at a 23% discount to vintage 2008 European Union Emissions Trading Scheme (EU ETS) allowances.
[23] A source-based market is more likely to behave like a competitive market than a load-based market, where regulators oversee the decisions of LSEs.
[24] Roughly one-half of California's GHG emissions associated with electric LSEs come from out-of-state sources. A number of these transactions come from identifiable generating units; however, many transactions do not.
[25] Out-of-state power sources emitting GHG at rates lower than the imputed rate would prefer to enter into bilateral agreements that would pay a premium for their lower emissions rates in a load-based system. In contrast, power sources with higher emission rates would prefer to be treated as system resources that would be given the lower imputed rate. Such perverse incentives constitute "adverse selection."

situation, a power plant that reduces its GHG emissions by one ton could extract a different value for that ton, depending on the mix of generators in the state where its power is consumed. Although each allowance can be surrendered to cover one ton of emissions, without accurate verification of the emissions, all allowances in a market with verification problems will be less acceptable for trading into other regional allowance markets and would trade at a relative discount.

First-seller/deliverer market design

The rules for awarding and authenticating allowances have not yet been determined. However, the perverse incentives associated with the use of imputed emissions would not exist in either source-based or first-seller systems, because the price of power sold to LSEs in each system will include the value of allowances.

Verified Environmental Integrity

The success of any emissions trading program depends on the level of confidence and trust between buyers and sellers. The maintenance of *environmental integrity* requires that "Any emissions covered by the cap-and-trade program must be monitored, reported, and verified to a high degree of accuracy. The inclusion of sources with emissions that are difficult to measure or verify would create the potential for undetected non-compliance and thereby undermine the environmental integrity of the system. If necessary data are not available, then the breadth of the program should be limited so that sources for which reliable emissions information is lacking are not included in the program."[26]

Source-based market design

Since the emissions sources are known, accurate monitoring, reporting and verification protocols can be developed and tested. This has been done in sulfur dioxide (SO_2), nitrogen oxide (NOx), and GHG source-based markets. In these markets technology developers and vendors are able to deal directly with the market segment that can directly apply the new technology. Vendors can benchmark their improved technology against existing technologies. Source-based measurement protocols tied to specific industries and technologies can provide high environmental integrity. In a market with environmental integrity each allowance surrendered accurately reflects one ton of equivalent GHG emissions. In a market where the allowances lack environmental integrity, either no inter-regional trading will occur or the prices of all allowances (or offsets) from that market will be discounted relative to prices for allowances (or offsets) in those markets that maintain a higher degree of environmental integrity.

Load-based market design

[26] California Air Resources Board, Market Advisory Committee, Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California. Final Report, June 30, 2007. p. 23. Available at http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF

Under a load-based compliance scheme, LSEs will have to become expert on the protocols for measuring, monitoring and verifying GHG upstream emissions, since they will be held responsible for the environmental integrity of emissions. In fact, each LSE will need to ensure that each of its power suppliers accurately measures and verifies its GHG emissions. However, under a load-based design inherent inaccuracies will exist for all those transactions originating out-of-state that are assigned a generic or imputed GHG emissions rate and for those sources that are not required to track emissions with comparable accuracy to sources located in-state. This is due to the need to adopt an accounting scheme to impute emissions for purchased system power and for power transactions from unspecified generating units. This difficulty is compounded by the administrative infeasibility of tracking a very large number of transactions from source to load. In the CAISO control area alone, there are 15,000 transactions per hour with 99 load schedules and 800 to 1,000 custody exchanges per hour between market participants.[27] The number of transactions and the need to cross-check totals to verify emissions will grow exponentially with the number of LSEs participating, making the scale-up of the load-based market design to encompass the numerous LSEs and 34 control areas in the WECC multi-state region cumbersome, at best, if not impossible.

The lack of a direct link between imported energy and emissions and the corresponding lack of accountability are major failings of the load-based approach. Even if load-based GHG emissions are estimated for indexing purposes, the inherent inaccuracies will preclude effective verification and affect the value of load-based allowances throughout the western region.[28]

In general, the development and deployment of improved technologies will be enhanced by creating broad market segments that are not constrained by political boundaries or electricity market boundaries. A load-based market, which would be distinguished by at least two-tiers of *environmental integrity* (i.e., Tier 1 for in-state sources and Tier 2 for unidentified out-of-state sources selling power imported to California), presents barriers to cross-boundary trading. The lack of environmental integrity for emissions associated with imported power is likely to cause all of California's load-based allowances to be priced at a discount in comparison to prices in other markets where allowances have higher environmental integrity. The lack of environmental integrity for California's load-based allowances will inhibit allowance trading with other regions and, thus, restrict access to the combined market segments and higher volume and liquidity of allowance transactions desired by technology developers and vendors. Overall, the lower environmental integrity of a load-based design will reduce the financial and environmental benefits of market integration.[29]

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[27] Lonnie Rush & Kyle Hoffman, CAISO, Presentation to the CPUC on April 12, 2007.

[28] As just one example, only about 56 percent of emissions from imported electricity can be precisely identified, according to a 2007 CEC report: Alvarado, A and Griffin K. Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports: Update to the May 2006 Staff Paper. Sacramento, CA: California Energy Commission, 2007. Such a situation does not satisfy the requirements for environmental integrity.

[29] If inter-regional trading were to occur between a load-based market and a source-based market like RGGI or the EU ETS, the price of the load-based allowances at any given time would have to be discounted to

First-seller/deliverer market design

For in-state resources, the first-seller approach provides the same *environmental integrity* as a source-based approach, because it is a source-based approach. However, first-sellers have the responsibility to assign GHG content to power they import, in a fashion similar to a load-based approach. Allocations and assignments by the first-seller/deliverer will be required, whenever more than one plant under contract to a first-deliverer provides power to the grid or when power is provided under contracts by unspecified plants or groups of plants.[30]

A first-seller approach, like the load-based approach, will have different levels of environmental integrity for in-state and out-of-state transactions. But, because the compliance responsibility is on the first-seller, verification may be more direct, and the overall environmental integrity of allowances in this market design should be somewhat higher than under a load-based approach. This, in turn, might make allowance trading easier between regional allowance markets, providing better market efficiency than under a load-based approach, but a less efficient market than would occur under a pure source-based approach.

Incentives for RD&D, Purchase & Utilization of Improved Technologies

The presence of an emissions cap that declines over time will provide pressure to retire high emitting sources, like conventional coal-fired power plants, under all three cap and trade market designs. However, the choice of market design will have important effects on technology investment and development incentives.[31]

A source-based design will place the greatest direct pressure on individual sources, while the load-based design spreads compliance risk across each LSE's portfolio of power purchases. The current U.S. source-based cap and trade system for SO_2 has led to fuel switching and installation of a variety of flue gas desulfurization scrubbers and other improvements in the processes of power generation. The allowance market has worked well to minimize costs while ratcheting down emissions, but, by itself, has not funded sufficient RD&D to create the diverse technologies now in operation. Although the ability to reduce the costs of compliance has provided incentives to purchase and use improved technologies, the Department of Energy, the Environmental Protection Agency and the

account for their lower verifiability and the reduced environmental integrity associated with imputed emissions.

[30] Although today's power contracts specify kWh, price, hours for delivery and delivery point, most contracts do not currently specify GHG emission rates/kWh. While the grid can deliver kWh at specific locations, it cannot deliver kWh with verified emissions content, unless each kWh delivered is tied contractually to a specific generating unit that is continuously monitored, measured and verified.

[31] The magnitude of research, development and demonstration funding needed to reach GHG reduction goals will require investment incentives beyond those provided by an efficient market-based GHG regulatory scheme. The chosen regulatory scheme will primarily influence the purchase and utilization of technologies needed to achieve compliance. Hence, it will also influence the investment and innovation needed to create the improved technologies.

Electric Power Research Institute, as well as manufacturers and vendors, have directly funded billions of dollars of RD&D intended to bring improved technologies to market. Thus, a combination of government and other funding incentives, including possible prizes for innovation and tax incentives,[32] plus the opportunity to make substantial profits will be needed to bring new technologies to market under all three cap and trade market designs. It should also be noted that worldwide technological innovation and the opening of new markets for U.S. technologies will be facilitated by the fungibility of emission allowances across different allowance markets, which will lead to greater opportunities for technology sales in markets around the world.

An LSE will not always be the most likely buyer of improved GHG reducing technologies, because some LSEs no longer own the power plants that serve their customers. Since LSEs are not individually adept at RD&D and cannot profit beyond their regulated rates of return, placing compliance responsibility on LSEs, rather than emission sources, will not motivate the R&D marketplace very much. Electric generators and electricity consumers are the market segments that should be directly targeted, and a source-based market is consistent with such direct targeting.[33] Likewise, when an electricity consumer sees the full costs of GHG reduction in its rates, the purchase of more efficient end-use technologies will become more attractive.

Under the load-based design there would be an ongoing misalignment of market incentives. After an initial rush of enthusiasm, vendors will not wish to spend time and money dealing with utility and regulatory bureaucracies, in order to develop and sell their products.[34] Without clear market signals backed up with allowances of known environmental integrity, technology investors will have less confidence in their ability to obtain the full value of their new technologies. Given more limited cost recovery and profit opportunities, it is more than likely that investors in clean technologies would be deterred by a load-based design. Overall, a load-based system will make it more difficult to "achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions …," which is a fundamental requirement of AB 32.[35]

Minimized Monitoring, Administrative, Transaction & Overall Costs

A well-designed cap and trade market covering multiple sectors will enable market participants with different compliance costs to trade allowances within and across different

[32] Investment and production tax credits, as well as emission taxes or fees can also play an important role, particularly in sectors without source diversity or where transaction costs for an allowance tracking system are high.

[33] Under any cap and trade system, the development of new resources will be supported by LSEs building new generation or contracting with new generation. Manufacturers will carry out R&D, and the amount of R&D will be a function of their perception of market opportunities, Renewable Portfolio Standards, tax credits and other subsidies.

[34] Some have argued that a load-based approach will encourage greater adoption of energy efficiency measures and renewable technologies. Since the CPUC in California currently mandates the adoption of energy efficiency measures and renewable generation technologies and can continue to do so, this is a debatable presumption.

[35] Assembly Bill No. 32, California's Global Warming Solutions Act of 2006 (Sec. 38560).

market segments, and, hence, to minimize both transaction costs and overall costs to achieve a mandated level of state, regional or national GHG emissions. Competitive markets work best, when there are many buyers and many sellers, and when price signals are transparent and unfettered.

Source-based market design

The administrative costs for a source-based GHG market for electric generators are likely to be similar to those experienced in the U.S. SO_2 allowance program and in the European Union Emissions Trading Scheme. Continuous emissions monitoring, an allowance tracking system and compliance procedures have been tested and are manageable. Administrative costs would be borne by government and by the source and internalized in product prices, e.g., in wholesale electricity prices. Electric generators are already familiar with source-based emissions regulation and compliance processes. In addition, each individual GHG source is more likely to understand its own technology needs better than its customers, such as LSEs. However, at this point in time, the risks for building new natural gas and coal plants are large, since the future prices of allowances are uncertain.

Because transaction costs, as well as other costs, can be internalized in the price of power, builders and operators of new technologies will have the greatest opportunity to recover their costs and to generate profits. Since a source-based system is more favorable for investment in, development of and the application of new technologies, it is likely that overall costs of achieving long-term GHG reduction goals will be lower under a source-based design, depending on the rate of penetration of improved technologies.[36]

Load-based market design

The tracking and verification costs for this type of allowance system will be borne not only by LSEs, but also by sellers and sources that must supply continuous information regarding their emissions. In fact, the requirement of sellers and sources to pass nearly continuous information along with MWh sales would be more burdensome than under a source-based system. LSEs will work to find the lowest costs to comply with the rules, and these costs will be passed along in electricity rates. Because of the huge number and nature of electricity market transactions, it is doubtful that accurate tracking can occur from sources to LSEs. Therefore, imputed emissions will be used for transactions involving out-of-state sources.

In any event, the transaction costs associated with monitoring, tracking and verification would be highest under a load-based approach, where the number of transactions to be

[36] In the short run, this may not be true for building combined cycle plants. Under a load-based cap and trade system, the utility can spread its compliance risk across many power plants. Under a source-based system, the plant developer bears the risks and the costs of acquiring allowances for a single plant or possibly multiple plants. However, under all market designs the plant operator/emissions source will bear the risks associated with plant performance and attainment of contracted or regulated target emission rates. Coal plant development without carbon sequestration would be expected to slow significantly and could come to a stop under cap and trade programs.

tracked will increase exponentially with the number of LSEs included in the program. Entities with little or no compliance experience, including middlemen, such as brokers, marketers and control area operators, such as the CAISO, and LSEs, such as Investor and Publicly Owned Utilities, Direct Access and Electric Service Providers, and Community Choice Aggregators will all become involved in the tracking and verification processes, even though only the LSEs will bear the compliance responsibility. Moreover, all electric power sources that emit GHG will need to accurately monitor, measure and allocate emissions to multiple power purchasers, so that downstream tracking can occur.

Proponents of a load-based system in California claim that only 55-60 LSEs would need to comply under a load-based system for California. However, they forget that the monitoring, allocation and tracking begins with emission sources, which would still need to be a part of an accurate GHG monitoring, tracking and verification system. Instead of supplying emissions information to one agency, like the U.S. Environmental Protection Agency or the California Air Resources Board, GHG sources operating under a load-based system would have to allocate emissions in real-time to all their power purchasers, who, in turn, must supply and verify that information to control area operators, marketers and brokers and, ultimately, to LSEs. This compliance burden can be legally mandated for sources within California. However, for sources outside California power purchasers would need to impose GHG monitoring and reporting requirements contractually or rely on imputed emission factors. As previously discussed, imputed emission factors are inherently inaccurate, and it has been pointed out that their use would restrict market transactions and give rise to perverse incentives for both clean and dirty generating units.

Since load-based transaction costs will be significantly higher and cost recovery for new technologies will be more problematic, there is likely to be a less favorable investment environment for cleaner technologies under a load-based system. Renewable resources will do fine under any cap and trade system, since they don't need to trade or acquire GHG allowances and can reduce the demand for allowances. Natural gas-fired combined cycle generating units would have contractual requirements under both market designs, as would other fossil-fired generators. Given the very high monitoring, administrative and verification costs and the relatively more limited number of entities for trading, the overall costs of achieving a given level of GHG reduction are likely to be higher under a load-based system. Furthermore, due to the assumptions regarding imputed emissions for imported power, there will be more uncertainty regarding the amount of reductions actually achieved.

First-seller/deliverer market design

The transaction costs and other costs of this approach are likely to be less than under a load-based design and greater than under a source-based approach. However, since transaction and other costs can be internalized in this design, investors should be more willing to develop and install cleaner technologies than under a load-based system. An expanded first-seller market that includes an increasing number of western states would look more like a source-based approach, since fewer sources would be excluded and, presumably, imputed emissions would be estimated more accurately, if only a very limited number of generators in the WECC remain outside of those states that adopt a first-seller market approach.[37]

Enhancement of Environmental Justice Goals

Most power plants in populated urban locations provide essential reliability and peaking services. Hence, power plants will continue to be needed in urban locations, most likely at existing plant sites, where environmental justice concerns are high, but siting alternatives are low.

Existing urban power plants tend to be older and less efficient, and they burn fossil fuels (natural gas in California). Because the global impacts of GHG emissions or emission reductions are not affected by their location, these urban plants might be good candidates for cheaper GHG reductions measured on the basis of $ per tonne of GHG reduced. Thus, under a cap and trade system these less efficient plants could be targeted for early replacement by new, lower emitting technologies.[38]

For the most part, the environmental justice community has advocated command and control regulation of GHG, in order to reduce the other pollutants released by urban power plants. However, the source-based cap and trade approach using GHG allowances for compliance, along with accompanying technology incentives, is more likely to lead to the earlier replacement of urban power plants by advanced generation technologies than would occur under a load-based market design.

Simplicity of Rules and Ease of Enforcement

A workable market design will require a system for enforcement, including penalties for emissions exceeding the allowances surrendered and for faulty measurement or misreporting emissions. Under a source-based market design the generator/emissions source will be responsible for measurement, reporting and allowance compliance. With a load-based or a first-seller/deliver market design, the LSE or the seller/deliver would likely have contractual arrangements that ensured they would not be held responsible for violations by the generator. Generators would still need to measure and report emissions content to market intermediaries, which would then pass on this data to the LSE or the first-deliverer. As discussed above, the assignment and verification of emissions is far simpler under a source-based approach. Unique allocation and verification may not be feasible or practical under either the load-based or first-seller/deliverer approaches.

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[37] In a pure source-based approach, generators/GHG sources located outside regulated states would be ignored, thus avoiding the need to impute emissions altogether. As the boundary of a first-seller approach expands to include an increasing percentage of all the fossil-fired generators in the WECC, the first-seller market design behaves increasingly like a source-based design.

[38] While a low GHG emissions standard measured in maximum lbs./MMBtu or tonnes/MWh is unlikely to be achievable at older, inefficient power plants, such plants can provide relatively cheap GHG reductions, when measured on the basis of $ per ton GHG removed. Nevertheless, because older gas steam power plants operate infrequently and will be needed for load following, it is also possible that these older facilities will remain in service, despite their relatively higher GHG emission rates.

Certainly, enforcement would be easiest and transaction costs would be lowest with a source-based market design.

Acceptable Magnitude and Likelihood of Unintended Consequences

As experience has demonstrated, over-regulated markets are prone to unintended consequences, since the desire to control market outcomes can lead to undesirable effects. California has only to look back to the years 2000 and 2001 to realize that poor regulatory designs can have serious adverse effects, leading to consequences that may have been foreseeable, but were certainly unintended.

Even after clean technologies are installed, the market incentives in a load-based system, which must rely on imputed emission rates for imported power, will be misaligned. As pointed out, because clean imported power from unspecified resources would be assigned an imputed emissions rate, generating technologies that are cleaner than the imputed rate may prefer to operate under bilateral contracts, in order to get paid for being cleaner, rather than making spot market sales at the higher imputed emission rates. The operational incentives under a load-based market are also perverse, since under MRTU, LSEs will not be able to control the dispatch of some higher emitting, but lower cost power plants, which need not include allowance costs in their wholesale prices. In addition, the lesser number of LSEs may enable some LSEs to exert undue market power during adverse market conditions, such as a low hydro year.[39] Furthermore, unless there is also source-based regulation for in-state resources to go along with the load-based system, it would be possible to "launder" dirty in-state emissions by selling to or exchanging dirty power with out-of-state buyers and replacing it contractually with cleaner generation, such as Pacific Northwest hydro or imputed emissions from non-specific resources. Here again, a tracking and verification nightmare emerges under a load-based system.

An assessment of the unintended consequences, including market manipulation, which might arise under these different market designs, is beyond the scope of this paper. Nevertheless, the likelihood and magnitude of possible unintended consequences should be thoroughly examined before a particular market design is adopted.

Timely Transition to a Regional or National Market System and Scalable in Size

In a load-based market the difficulties of measuring, allocating, tracking, aggregating and verifying emissions for power sold to LSEs would grow exponentially as more and more LSEs and transactions are included. Hence, a load-based approach can not be practically scaled up to regional or national levels. In contrast, a source-based approach can be scaled up, since the responsibilities lie with each regulated source. As the size of the geographic region approaches the size and coverage of the WECC, a first-seller/deliverer market

[39] In past years low hydro conditions in California and the West have increased fossil-fired generation in California by as much as 25 percent above average hydro conditions.

design will behave increasingly like a source-based market. Currently, all major proposals for U.S. national cap and trade legislation rely on a source-based market design.[40]

There are also many questions concerning the dismantling of load-based compliance systems and the timely transferability of load-based allowances into a national source-based allowance system. The difficulties in doing this were amply displayed by the U.K., when it closed out its load-based system and moved to the source-based EU ETS. Maintaining two different regulatory systems would be unnecessarily costly, so a transition to a U.S. national system should be anticipated.

Satisfies AB 32 in California

California's Assembly Bill 32, passed in 2006, requires broad-based, multi-sectoral emissions reductions to achieve GHG emissions goals.[41] Depending on how it is implemented, each cap and trade market design discussed here would encompass both in-state generated emissions and out-of-state emissions associated with power imports, and each could satisfy AB 32. But, without the timely cooperation of other states and affected out-of-state entities, none of these designs will be able to satisfy the intent of AB 32.

4. CONCLUSIONS

In the comparisons presented above, we discussed the capabilities of each market design to achieve the following important market objectives:

- Clear market price signals,
- Uniform and stable GHG allowance prices,
- Verified environmental integrity,
- Sufficient incentives for RD&D, purchase and use of improved technologies,
- Minimized monitoring, administrative, transaction and overall costs of compliance,
- Enhancement of environmental justice goals,

[40] A cap and trade market that operates on a national scale will also provide greater opportunities for federal tax incentives and for technology RD&D policies to complement the incentives provided by the value of the allowances freed up by reducing GHG emissions.

[41] Assembly Bill No. 32, California's Global Warming Solutions Act of 2006, requires the state Air Resources Board to adopt regulations for reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with a specified program. The bill mandates a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020, and requires the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions, as specified. The bill authorizes the state board to adopt market-based compliance mechanisms, meeting specified requirements. The bill requires the state board to monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board, pursuant to the specified provisions of existing law. The bill also gives the state board the authority to adopt a schedule of fees to be paid by regulated sources of greenhouse gas emissions.

- Simplicity of rules and ease of enforcement,
- Acceptable magnitude and likelihood of unintended consequences,
- Scalable in size and enables a timely transition to a large regional or national market, and in California
- Satisfies the requirements of AB 32.

A regulated source-based market is more likely to achieve the above objectives than the other two market design options. With respect to technology incentives, the comparisons show that a source-based market with its clearer valuation of competitive allowance prices and its better internalization of costs in market prices would provide better incentives for the development and application of new technologies than either a first-seller/deliverer approach or a load-based design. In turn, a first-seller/deliverer approach is preferable to a load-based approach.

Several reasons why a source-based market design should be preferred are:

1) A source-based market design is simpler, and its implementation will have lower costs and lead to faster implementation.
2) Load Serving Entities are less likely to make investments in innovative or improved supply side technologies to reduce GHG emissions than are the emissions sources themselves.
3) Source-based emission reductions can be more accurately tracked and verified. In any case the responsibility for monitoring and accurate reporting will be placed on emissions sources, even if a load-based market design is adopted.
4) The environmental integrity of emissions allowances is greater in a source-based market than in a first-seller/deliverer market, which in turn, is higher than in a load-based market.
5) Emissions allowance price signals emanating from LSEs in a load-based market will be adulterated and passed imperfectly both upstream and downstream, as compared to more direct price signals in either a source-based or first-seller/deliverer allowance market.
6) Incentives to purchase and utilize improved, lower emitting technologies will be greater under a source-based approach than under either the load-based or the first-seller deliverer approaches,[42] and
7) The transition to a national source-based cap and trade market will be easier, faster and less costly, if states adopt a compatible source-based approach.

Because of its similarities to a source-based market, particularly as its geographic coverage expands, the first-seller/deliverer approach is more likely to function competitively and

[42] The incentives are better, partly because there are fewer gaming opportunities for achieving compliance under a source-based cap and trade system. The adverse selection for generating sources under a load-based system will also reduce the environmental integrity of all allowances in a load-based system, potentially reducing the prices of such allowances in interregional or international trading.

keep overall costs lower than a load-based approach. The strengths and shortcomings of source-based markets have been tested in practice, while there are many shortcomings of the load-based approach that make this market design unworkable, more costly and not scalable up to multi-state coverage levels.[43] The first-seller/deliverer approach is a hybrid of these two market designs, such that its expected impacts lie in between those expected under the two alternatives.

Under the load-based design there will always be a misalignment of market incentives. Vendors do not wish to spend time and money dealing with utility and regulatory bureaucracies, in order to develop and sell their products. Without clear market signals backed by allowances with established environmental integrity, technology investors will have less confidence in their ability to obtain the full value of their new technologies. Given more limited cost recovery and profit opportunities, it is more than likely that investors in clean technologies would be deterred by a load-based design. Moreover, the adoption of a load-based system will make it more difficult to "achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions ...," which is a basic requirement of California's AB 32.[44]

In summary, the foregoing comparisons show that a load-based system would be more complex, costly and inaccurate than either a source-based or a first-seller system. Trying to institute a regional load-based cap and trade system and failing to achieve the fundamental market objectives would set back public confidence in any carbon emissions reduction scheme. On the other hand, technological innovation will be driven by the greater value that can be realized under source-based and first-seller/deliverer market designs.

Therefore, we recommend the adoption of a regional and, ultimately, a national source-based cap and trade GHG allowance system. To comply with Assembly Bill 32, passed in 2006, we recommend that California and other western states adopt an integrated source-based cap and trade system with broad enough geographic coverage to include most of the power sources now serving California and other western LSEs. As a second choice, which would incur unnecessary costs prior to the transition to a national cap and trade system, we recommend that California and other western states adopt a first-seller/deliverer market design with provisions for replacing it with a regional or national source-based system, as soon as possible.

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[43] As discussed elsewhere, the load-based market design envisioned in California will be infeasible and unworkable for numerous reasons. See, for example, Van Horn Consulting, <u>Comments on the Market Advisory Committee's Draft Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California</u>. Submitted to the California Air Resources Board, June 12, 2007.

[44] California Assembly Bill AB 32 (Sec. 38560), 2006.

Attachment B

State Efforts to Cap the Commons: Regulating Sources or Consumers?

Dallas Burtraw
Resources for the Future
November 9, 2007

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State Efforts to Cap the Commons: Regulating Sources or Consumers?

November 9, 2007

Abstract:

California's Global Warming Solutions Act (Assembly Bill 32) requires the state to reduce aggregate greenhouse gas emissions to 1990 levels by 2020. One of the challenges California faces is how the state should regulate the electricity sector. About 80% of the state's electricity consumption is generated in the state, but about 52% of the greenhouse gas emissions associated with electricity consumption comes from outside the state. The question addressed in this paper is where to locate the point of compliance in the electricity sector—that is, where in the supply chain linking fuel suppliers to generators to the transmission system to retail load-serving entities should the obligation for measurement and compliance be placed. The conclusion offered is that one particular approach to regulating the electricity sector – the "first-seller approach" – would be best for California. The alternative "load-based approach" has a running head start in the policy process but would undermine an economy-wide market-based emissions trading program.

1 Introduction

In 2006 California adopted the California Global Warming Solutions Act (Assembly Bill 32), which requires the state to reduce aggregate greenhouse gas emissions to 1990 levels by 2020. The act charges the California Air Resources Board to develop a comprehensive plan for implementation by January 1, 2009; the plan will involve a number of state agencies. Whether the state will rely on prescriptive technological standards, incentive-based approaches such as cap-and-trade, or a combination is a decision that will be made in the next couple of years.

One of the challenges California faces is how the state should regulate the electricity sector. Electricity consumption accounts for 23.5% of the greenhouse gases in the state, including about 27.7% of the carbon dioxide (CO_2) emissions. This is low on a per capita basis compared with the rest of the country, where electricity consumption accounts for about 33% of greenhouse gases and about 40% of CO_2 emissions (which is about 9% of total CO_2 emissions worldwide).[1] The largest category of greenhouse gas emissions in California is transportation, which accounts for about 40.4% (California Market Advisory Committee 2007). Nonetheless, the electricity sector remains very important to the design of the California trading program. First, the electricity sector is typically identified as the source of most potential greenhouse gas reductions in the near term. Modeling at a national level indicates that the electricity sector is responsible for about 40% of the nation's CO_2 emissions but will account for between two-thirds and three-quarters of emissions reductions in the next two decades under national policy (EIA 2007; Pizer et al. 2006). Second, experience with cap-and-trade has been largely in the electricity sector. Previous programs, including the sulfur dioxide (SO_2) and nitrogen oxide (NO_x) trading programs in the United States and the Emission Trading Scheme for CO_2 in the European Union focus exclusively on point sources, largely made up of electricity generators. The electricity sector is the demonstrated successful testing ground for this type of regulation.

<insert Figure 1 here>

Although California's own generation resources are low emitting, its imported power is relatively high emitting. About 80% of the state's electricity consumption is generated in the state, but as illustrated in Figure 1, about 52% of the greenhouse gas emissions associated with electricity consumption comes from outside the state (CEC 2006). Attempts to regulate only in-state sources would be expensive per ton of emissions reduction compared with the opportunities to reduce emissions on a broader scale. Given the open transmission system, attempts to regulate only in-state sources also would lead to more imported power, with an associated increase in emissions out of state. The act anticipated this issue by requiring that the state's greenhouse gas reduction target include the out-of-state emissions associated with California electricity consumption.

This paper addresses options for regulation of California's electricity sector within the context of an economy-wide cap-and-trade program in the state, and

[1] The Market Advisory Committee (2007, 41) reports that the carbon intensity of electricity generation in California in 2004 was 700 pounds of CO_2 per MWh. Accounting for imported power brings the average emissions intensity of electricity consumed in the state to 930 pounds per MWh. Across the nation, the average emission intensity of electricity generation is 1,176 pounds per MWh.

potentially for the nation. The major decision addressed in this paper is where to locate the point of compliance in the electricity sector—that is, where in the supply chain linking fuel suppliers to generators to the transmission system to retail load-serving entities should the obligation for measurement and compliance be placed. Sections 2 sets out the different approaches that have been suggested, and Section 3 addresses the debate about these approaches in detail. Section 4 provides a conclusion.

The conclusion offered is that the "first-seller approach" to regulating the electricity sector would be best for California. The alternative, the "load-based approach," has a running head start in the policy process and is more familiar to many advocates and policymakers. Most of the reasons cited to advance the load-based approach over the first-seller approach are in fact differences without a distinction: the approaches would have the same effect. For example, the load-based approach would provide additional incentives for efficiency investments, but so would the first-seller approach. However, the approaches differ in some fundamental ways. The load-based approach would have greater complexity, and it would not provide transparent signals to electricity generators about the scarcity value of CO_2 in the economy. A load-based approach would appear substantially different from existing markets for environmental goods, and indeed, it might be more accurately described not as a market but as increasingly flexible regulation.

It is most important for policymakers to recognize that the future of electricity markets and allowance markets are intertwined. If the vision for the future of California's electricity markets were regulation as currently practiced, then the load-based approach would not be inconsistent. But if the goal is to increase competition—for example, through the introduction of a day-ahead market as planned, for 2008—then the load-based approach to a cap-and-trade program would pose a fundamental conflict.

2 Point of Compliance for CO_2 Cap-and-Trade in California's Electricity Sector

One month after passage of the California Global Warming Solutions Act, Governor Schwarzenegger issued an executive order creating the Market Advisory Committee to advise the California Air Resources Board (CARB) on developing a plan for a cap-and-trade program. One alternative identified by the committee is an "upstream" approach that would regulate emissions at the point where fossil fuels enter the economy. Implementation at this point could achieve coverage of 83% of the greenhouse gas emissions in the state by regulating 150 facilities.[2] Under this approach, the question of how to regulate the electricity sector would not be relevant because carbon emissions would be regulated before they entered the electricity fuel cycle.

However, the approach that received the most attention, partly based on precedent in other trading programs, is "midstream" regulation. As illustrated by Figure 2, this approach would regulate midway in the fuel cycle between the introduction of fossil fuels into the economy and their end use. This approach could achieve comparable coverage of

[2] This approach would require monitoring and reporting for all fossil fuels produced in or imported into California, as well as fuel exports. This includes about 100 business entities that take delivery of gas via a pipeline.

83% of the state's emissions by regulating 490 facilities, assuming that transportation fuels would be regulated at the refinery.

<insert figure 2 here>

We focus on the question of how the midstream approach would be implemented in the electricity sector. Two approaches have been discussed most thoroughly. One, a *load-based approach,* would shift compliance responsibility downstream from the point of combustion and would place a legal obligation for reporting and compliance with the load-serving entities—the firms that sell retail electricity directly to customers. Compliance implies that these entities would be responsible for surrendering an allowance for every ton of CO_2 used by electricity generators upstream to provide electricity services to their customers. In a decision that preceded the statewide legislation, the California Public Utilities Commission (PUC) had already identified a load-based approach for regulating greenhouse gases in the electricity sector in California. PUC regulates the private investor-owned utilities (IOUs) that provide about 80% of the state's retail electricity. Under statewide legislation and implementing regulations to be developed by CARB, the remainder of the population served by municipal utilities and others would also participate.

The alternative approach was proposed initially by the Market Advisory Committee (2007) and is known as a *first-seller approach.* It would place a legal obligation for reporting and compliance on the first seller of power into California electricity markets. The first seller is the owner, operator, or power marketer for a generation facility located in the state, or the party bringing power onto the electricity grid for power generated out of state. Compliance would be required for power placed into the transmission system from that facility. For in-state sources, a first-seller approach would look very similar to the source-based system that characterizes previous trading programs, such as the SO_2 trading program, in which compliance is required at the point of combustion—that is, where emissions are released into the atmosphere.

Both approaches are imperfect tools for dealing with imported power, as we discuss below. It is worth emphasizing that if California's program is integrated into the efforts of the six states and two Canadian provinces participating in the Western Climate Initiative and a cap-and-trade program emerges in this broader geographic region, the issue of electricity imports will be much reduced. The other states participating in the initiative are Washington, Oregon, Arizona, New Mexico, and Utah.

The Western Electricity Coordinating Council coordinates power dispatch over the western electricity grid and encompasses portions of 14 western states (including the entirety of 11 states) along with British Columbia and Alberta. The western grid operates largely in isolation from the rest of the nation. The Western Climate Initiative would bring the vast majority of power generated in the region into the trading program. It is also worth noting that the first-seller approach would naturally evolve into a source-based program, since a growing proportion of generation sources are located within the trading region, but the load-based approach would retain the point of regulation on load-serving entities (LSEs).

Another crucial issue in the design of the program is the method of initially distributing emissions allowances. As Figure 2 illustrates, there is no reason that the point of allocation and the point of compliance should be the same. In fact, a substantial literature has advocated for the use of an auction rather than free allocation for distributing allowances.[3] This is the approach being used for 100% of the allowances being distributed by New York and 5 other states in the 10-state Northeast Regional Greenhouse Gas Initiative (the remaining states are still considering their plans).[4] An auction approach also was the approach highlighted as preferable, especially after a transition period, by the Market Advisory Committee.

3 Analysis of Point of Compliance

Several issues have surfaced in deliberation about the point of compliance as advocates for one or another viewpoint have tried to distinguish the two approaches.[5] I address these issues in three groups. The first group is where differences of opinion abound, although there is fundamentally little or no distinction to be made in performance between a first-seller and a load-based approach. The second group of issues do involve fundamental distinctions. The third comprises issues where the jury is still out, especially on the legality of these approaches.

3.1 Where There Are Differences without Any Distinction

Proponents and opponents of each approach contend that the choice would affect the regulation of imported power, procurement policies, and efficiency policies and have effects on both producers and customers of electric power. The alleged differences in the performance of the load-based and first-seller approaches do not hold up under scrutiny, however.

3.1.1 Regulating Imported Power

California cannot regulate or impose financial regulatory burdens directly on out-of-state sources, but it can indirectly affect the use of out-of-state generation. This is the primary motivation for looking beyond a source-based approach to regulation, and it is the reason most often cited in favor of a load-based approach. However, the load-based approach is a very imperfect way to regulate out-of-state emissions, and the first-seller approach is no better. One problem for both approaches is the imprecise assignment of emissions to generation for at least some portion of imported power. Another difficulty is "contract shuffling," which is the opportunity for wholesalers of out-of-state power to shift the assignment of existing sources with relatively low emissions rates to serve California while assigning higher-emitting sources to serve other load centers outside California. Bushnell (2007) argues that the opportunity may exist for 100% contract

[3] See, for example, Parry (1997) and Goulder et al. (1999), who demonstrate that an auction with revenue recycling aimed at reduction of other taxes dramatically lowers the social cost of the policy. Burtraw et al. (2001) demonstrate that an auction also has the property of providing more efficient pricing regulated regions of the country. CIER (2007) demonstrates that an auction can provide revenues that reinforce program goals by funding investments in energy efficiency and thereby lower the cost of the program for consumers.

[4] The initiative's memorandum of understanding specified that all states should allocate at least 25% of the emissions allowances created by a cap-and-trade program to consumer benefit and strategic energy initiatives. An auction of allowances is the most likely way to implement this policy.

[5] See, for example, the proceedings and supporting documents submitted at the Joint En Banc Hearing of PUC and CEC on Point of Regulation in the Electricity Sector in San Francisco on August 21, 2007.

shuffling, meaning all of the imported power coming to California could be identified as zero emissions without any real change in the resource mix throughout the western electricity grid.

There is reason to believe that the opportunities for contract shuffling may be limited. Both approaches would rely on the California Climate Action Registry's Power/Utility Reporting Protocol, which assigns emissions intensity to imported power. According to a recent study by the California Energy Commission (Alvarado and Griffin 2007), this approach allows for a precise identification of the power plant and associated emissions for about 56% of imported power. The remainder would have to be assigned emissions intensity based on other information, such as the average emissions intensity for the control region from which the power is delivered into California. The transmission path for imported power cannot be tracked directly, but the financial path can be tracked based on the information in electronic North American Electric Reliability Council (NERC) E-tag documents.[6] Under either approach, this is the information that regulators would use to make an assignment of emissions out of state to the use of electricity in California. Under a load-based approach, information about the emissions intensity of imported power would be conveyed downstream to the LSE. Under a first-seller approach, this information would be the measure upon which to base the compliance responsibility of the party listed on the E-tag document—that is, the party that is the first seller of imported power to the electricity grid.

In sum, the basis for assessing the emissions intensity of imported power would be the same for both approaches, and the approaches are similar in their ability to account for imported power. The difference between them stems from what happens on the California side of the boarder. The load-based approach would require an additional level of approximation in making an assignment between the contracting party identified as the first seller and the LSE that has the compliance obligation—something we discuss in Section 3.2.

3.1.2 Procurement Policies

A second issue of little distinction is how the choice of a point of compliance would affect PUC's portfolio-planning activities. PUC plays an important role in ensuring that dispatch meets social goals through a variety of previous orders, including most generally the procurement standard, which specifies the order in which regulated utilities should develop resources to meet demand. The order gives priority to efficiency first and renewables second, before turning to fossil-fired generation. Advocates of a load-based approach argue that this approach is necessary to support PUC's role.

Would or should PUC's supply-side procurement policies end if there is a greenhouse gas cap-and-trade program? From PUC's perspective, the answer is obviously no. PUC's policy development in this area predates events that have moved climate policy to center stage in California and reflects long-standing goals for reducing

[6] NERC E-tags are electronic documents used to track the transmission of electricity so that sources of grid congestion can be more easily identified and mitigated. In addition to identifying the parties with financial ownership of the power, the E-tag identifies the source and destination control region. Parties identified on the E-tags are licensed to schedule power into the transmission grid.

air pollution, promoting stability in the supply and price of energy resources, and promoting economic development in the state.

Would it make a difference for those policies whether a load-based or a first-seller approach was adopted? One can be equally emphatic in answering this question, although the issue is more subtle. PUC's initiative toward developing a greenhouse gas program follows on top of the other policies and is not intended to substitute for them. PUC initially declared its intent to develop a load-based cap on electricity sector emissions in February 2006, well before passage of the California Global Warming Solutions Act. The load-based approach was chosen not because it was the preferred design to complement the other goals but because it was the only option available to PUC for designing a cap on electricity sector emissions. PUC regulates investor-owned utilities, which account for roughly 80% of the delivered electricity supply in California. Furthermore, the generation fleet of the IOUs is predominantly nonemitting nuclear, geothermal, wind, and hydroelectric resources, and a large portion of the IOUs' load is met with system power. PUC regulates only IOUs, and not the independent power producers and others who sell power to the IOUs. A source-based emissions cap on the IOUs' own generation would have little benefit because IOU generation is already so clean and because the majority of emissions used to serve the IOU load would remain unregulated. Therefore, PUC has limited options when it comes to regulating emissions within the state.

In designing an emissions cap, PUC had only one option, to impose requirements on the load-serving function of the IOUs. This is the same regulatory handle that is exercised in other rules governing how the IOUs meet their resource requirements. For example, as mentioned above, PUC's "loading order," adopted in May 2003 as part of the state's Energy Action Plan, establishes the priorities for energy procurement for IOUs. In December 2004, PUC adopted a CO_2 cost adder of $8 to $25 per ton to be added into system dispatch, and in October 2005, it issued a policy statement on a greenhouse gas performance standard.[7] These are all load-based approaches to regulation because that is the main way that PUC can affect IOU practice, and it can affect other sources only indirectly. Furthermore, all these requirements will remain in place whether a statewide cap-and-trade program targets the LSEs or the first sellers.

Acting by itself as an independent agency, PUC did not realistically have the option of directly regulating sources or first sellers when designing its greenhouse gas policy. It was making a virtue of necessity by initially adopting a load-based approach when it began to consider cap-and-trade policy. Given the new act's mandate to cover sources statewide, PUC and its sister agencies now have the ability to design a different kind of policy.

3.1.3 Efficiency Policies

A related set of questions concerns the ability of PUC to implement its efficiency programs. Since the 1970s, California has been a world leader in efficiency programs.

[7] Senate Bill 1368 expanded this approach and directed the California Public Utilities Commission and the California Energy Commission to set a greenhouse gas performance standard to ensure that new long-term financial commitments in baseload power plants by electric load-serving entities have greenhouse gas emissions that are as low as, or lower than, emissions from a combined-cycle natural gas power plant. In May 2007 PUC adopted greenhouse gas standards for procurement.

PUC has decoupled revenue from sales for California's IOUs in an effort to remove the disincentive for IOUs to invest in programs that would reduce their sales. Recently, PUC moved to provide stronger positive incentives for IOUs to invest in efficiency by rewarding the achievement of certain goals. As with the supply-side policies, the demand-side policies are intended to encourage low-income assistance as well as lessen the overall environmental impact of electricity use.

Would or should PUC's demand-side efficiency programs be changed or stopped if there is a greenhouse gas cap-and-trade program? The answer clearly is no. Nonetheless, proponents of a load-based approach have suggested that this approach would do a better job of achieving emissions reductions because it would raise awareness in the firm regarding investing in efficiency and renewables and lessening reliance on fossil fuels. Since the load-serving entity is closer to the end use and typically is charged with administering efficiency programs, the argument goes, the greenhouse gas program should be placed at this point in the supply chain.[8] Further, firms are said to respond less well to a price signal than to a direct regulatory obligation, and therefore one could expect a more robust investment in efficiency if the point of compliance with the cap-and-trade program were placed on the LSE.

One could build intuition for that argument from the earliest actions by firms to implement the SO_2 trading program under the 1990 Clean Air Act Amendments, but it would be a misreading of what has been learned since. Initially, at dozens of facilities, plant managers and engineers who had not previously focused much on SO_2 emissions and who knew little about the concept of cap-and-trade began to experiment with more thorough fuel washing and expanding their use of mid- and low-sulfur coal. Vendors, meanwhile, began to experiment with the sorbent injected into desulfurization scrubbers. For the first time, all these parties had an incentive to go beyond a simple performance standard.

The SO_2 program got the attention of plant managers and engineers, but within a short time compliance responsibility was taken away from them because emissions allowances came to be viewed as a financial asset. Compliance with the cap-and-trade program was kicked upstairs and folded into fuel purchase decisions. Plant managers and engineers were given an incentive to reduce allowance use analogous to their incentive to reduce fuel use. A ton of emissions avoided was an allowance earned, as valuable as reducing fuel expense, and there were trade-offs to be made along these dimensions. This organizational learning was one of the subtle ways that incentives led to innovation, as firms learned to reduce their costs of compliance under the SO_2 program (Burtraw 1996). Today, firms think of the market-based SO_2 program as a financial problem managed by trading desks. They have moved beyond autarkic behavior with trading internal to the company and have become active in the external market, and the management of plants is functionally the same as if they faced an emissions tax or a change in upstream fuel prices (Ellerman et al. 2000; Swift 2001).

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[8] For example, testifying before the Joint En Banc Hearing of PUC and CEC on Point of Regulation in the Electricity Sector in San Francisco on August 21, 2007, Richard Cowart called LSEs "ideally positioned through portfolio management and their buy decisions. It sends signals upstream to generators and they also have relationships with customers. So, they can work with customers to reduce carbon emissions. So, they have also the potential of affecting decisions downstream."

Siting SO_2 compliance activities at one or another level in the firm or market will not lead to any further emissions reductions because the industry operates under an emissions cap. With a CO_2 cap-and-trade program in California, the same result will obtain: it is the cap that will determine the level of emissions, not the point of compliance for the regulation. If the regulation imposes compliance at a level intended to directly affect corporate culture and organizational behavior rather than directly achieving emissions reductions, it could potentially raise costs for firms and thereby raise the social cost of the program. But it will not do anything for achieving environmental goals because emissions will be capped.[9]

3.1.4 Impacts on Customers and Producers

Will there be different impacts on customers and producers? Where markets determine the price of electricity, the incidence of the program (i.e., how the cost burden is shared among customers and producers) is determined by the elasticities of supply and demand in that market, not where the regulation is applied. The wholesale price of power would be different under these two approaches, but the retail price effect is expected to be identical. To the extent the wholesale electricity market is competitive and retail prices allow for a pass-through of costs, it makes no difference where the point of compliance is located with respect to the effect on consumers. To the extent that the wholesale market does not appear transparently competitive, it is foremost the result of regulatory intervention meant to protect consumers as well as achieve environmental goals.

Advocates for a load-based approach have pointed to the possibility that under a cap-and-trade program, producers could gain windfall profits at the expense of consumers. The issue of windfall profits has gained attention since evidence has emerged of billions of dollars in unanticipated earnings due to free allocation of emissions allowances in the European Union's Emission Trading Scheme (Sijm et al. 2006).

Under a cap-and-trade program, producers receive compensation two ways. One way is the potential allocation of free allowances. The second way is through changes in the wholesale power price, where the increase in revenues is determined by the increase in the marginal cost of the marginal generator. All sources selling into the market receive the increase in revenue as determined at the margin, whether one's change in cost is greater than or less than that of the marginal generator. Typically, the marginal facility is a natural gas plant, whose CO_2 emissions, though substantial, are still less than half those from the average coal-fired plant. As illustrated in Figure 3, at low-emitting or nonemitting facilities where there is little or no change in cost associated with the program, the change in revenues is likely to represent an increase in profitability even if allowances are purchased in an auction.

<insert figure 3>

Effects in Figure 3 are illustrated for an individual facility; however, an individual facility does not really have standing. The shareholders of firms own a portfolio of facilities, and some facilities gain value and some lose value. The effect on a firm is an

[9] Parties have made an indirect argument that changing corporate culture may make it easier to amend the cap in the future. However, the converse argument is that raising costs may erode political support for environmental goals.

aggregation of effects on facilities in the firm's portfolio. Consequently, some firms win and some lose. The winners tend to be firms with relatively low compliance costs because they own a portfolio of relatively low-emitting plants. These firms will realize an increase in revenues associated with the rise in the wholesale electricity price that is greater than their own change in compliance costs. Conversely, any gain in value for one particular facility does not necessarily map into a gain in value for the portfolio of facilities owned by a firm.

Looking at the Northeast's Regional Greenhouse Gas Initiative and accounting for the portfolio of generation assets owned by companies, Burtraw et al. (2006) find that even under an auction, 11 of the 23 largest generation companies in the region would realize an increase in market value. If allowances are given away, one can expect a gain in profitability on a broad scale. These authors find that under free allocation of emissions allowances to generators, each of these companies at least breaks even, and several see substantial increases in value.

In California a large number of facilities, including nuclear, wind, geothermal, and hydroelectric plants, have zero emissions. The regulated IOUs own most of these facilities, and the increase in value of these facilities would be returned to ratepayers. Nonetheless, this does not allay the concern that free allocation of emissions allowances could lead to windfall profits for most if not all generation companies.

The key idea is that windfall profits are related to free allocation, not the point of compliance. Many people advocate a load-based approach to get away from free allocation of emissions allowances to generators and implicitly to assign allowance value to customers. This reasoning makes the mistake of lumping together point of compliance and point of allocation, but as Figure 2 illustrates, it does not have to be that way, and the Market Advisory Committee strongly recommended against it. The point of compliance would not affect how the cost of the program is distributed. Where emissions are properly accounted for, the effect on the retail power price is identical and the effect on the value of generation assets is identical.

Policymakers have a degree of freedom: they could, for example, distribute allowance value among customers and producers to achieve any distributional outcome that is desired.[10] A load-based approach with an auction would have the same effect on retail prices as the first-seller approach with an auction. Alternatively, one could have a load-based approach and freely allocate allowances to generators, who would then sell them to LSEs, and generators would earn substantial profits.[11]

[10] The Market Advisory Committee suggested that assignment of value is preferable to allocation of allowances. If allowance value is assigned in the near term, that assignment could be phased out over time to allow retail price adjustments in the future. The allocation of allowances also could be phased out, but the committee reasoned that it would lead to a greater sense of entitlement to allowances.

[11] Both approaches preclude grandfathered free allocation to generators because of the difficulty of assigning allocation to importers. However, another type of free allocation, known as updating (in Europe this is described as benchmarking), can be used. Updating allocation is done on the basis of production and the current or very recent period. Because there is essentially an output subsidy in the form of free allowances based on output, updating provides an incentive for electricity generation. Compared with grandfathering, an updating approach tends to lessen the likelihood of windfall profits because of its effect on the product price (Burtraw et al. 2005).

In any outcome, one should guard against the parochial assignment of this allowance value to the electricity sector—that is, the notion that the allowance value is a pie that can be shared among electricity customers and producers. The economic value of allowances is not created in the electricity sector; it is created by a societal commitment to place a scarcity value on CO_2 emissions throughout the economy. The fact that electricity has incumbency as a heavy emitter of CO_2 emissions does not mean the value of carbon allowances belongs to electricity customers or electricity producers.

Given society's decision to place a value on the use of CO_2, an assignment of the value of carbon allowances to electricity customers rather than producers constitutes a windfall to electricity consumers if the value is used to subsidize the electricity price. Minimizing the politically unpopular effect on price has been an explicit objective of many advocates. The practical design of public policy success requires a transition in the changes in relative prices in the economy. This will lessen the cost of the program by lessening the economic disruptions associated with an abrupt change in policy.

However, if policymakers remain wedded indefinitely to an electricity price that does not reflect the scarcity value of CO_2 while other sectors of the economy are treated differently, then the marginal cost of emissions reductions will differ across the economy, potentially greatly increasing the cost to the economy of emissions reductions. It will also undermine consumer decisions with respect to investments in end-use efficiency because electricity will be priced below its marginal social cost. This is why the Market Advisory Committee recommended a mixed approach of auction and free allocation, with the auction growing over time, and allowance value assigned to reinforce program goals and to meet social priorities rather than to compensate producers or consumers in the long run.

3.2 Where There Are Real Distinctions

A second group of issues involves real differences in how load-based and first-seller programs would perform. One issue is administrative in nature, a second concerns monitoring and incentives, and a third is environmental integrity.

3.2.1 Administration

The virtue of a cap-and-trade program, according to economists, is that it is simple in both theory and practice. The traditional prescriptive regulatory approach (a.k.a. command-and-control) seems simple until one accounts for the endless and idiosyncratic variances that have to be reviewed for virtually every facility. The U.S. Environmental Protection Agency has found it dramatically simpler to administer cap-and-trade—nationwide, for example, only about 100 government staffers implement the SO_2 and NO_x trading programs (EPA 2003)—and this contributes to transparency and the perception of fairness associated with cap-and-trade. One of the pleasant surprises of the SO_2 trading program was the paucity of litigation, compared with what is expected when traditional rate-based or technology-based standards are implemented (Burtraw and Swift 1996).

Simplicity in theory and practice would not describe the load-based approach, however. With respect to the treatment of imported power, the load-based and first-seller approaches share complicated accounting and administration. But for in-state generation, the first-seller approach easily identifies and accounts for emissions, whereas the load-based approach introduces complexity and imprecision in making an assignment of emissions to generation that occurs in the state as well as out of state. To account for emissions associated with electricity consumption, computer software will have to link emissions to load in a manner that will lack transparency and be difficult for third parties or even market participants to verify. In California the Independent System Operator (ISO), which oversees most but not all of the state's grid, manages roughly 15,000 transactions hourly. To track these transactions and their associated emissions is a tremendous project even under the best of circumstances.

3.2.2 Monitoring and Incentives

However, the emissions trading program is not being introduced under the best of circumstances, and consequently the load-based approach will not be able to assign emissions to load in a precise manner. One source of imprecision comes from ancillary operations providing load balancing, voltage support, and spinning and nonspinning reserve services to the electricity market, which account for 5% to 7% of the energy procurement in the state. These services are typically applied by auction by most ISOs, and the bidding structure has no information about the emissions profile. In the context of the grid, ancillary services are a public good and their benefits cannot be uniquely assigned to one or another LSE. Therefore, emissions associated with ancillary services are assigned to LSEs arbitrarily. It follows that the LSEs would lack the ability to influence emissions associated with ancillary services in this portion of the market. In contrast, emissions associated with ancillary services would be naturally assimilated in a first-seller approach.

Under a load-based approach, imprecision of measurement in the ancillary market and the general structure of the wholesale market will erode the incentive for most generators to reduce emissions on an even broader scale. In a competitive wholesale market, the marginal generator sets the price. Imagine the market-clearing price is set by generator i and the price per megawatt-hour of electricity (p) is equal to the marginal cost (g_i) of generator i. All other facilities (j) with marginal cost (g_j) less than g_i earn p as well. These facilities have an inherent incentive to reduce their generation cost because their profit is equal to the difference between revenue and cost; that is, $p - g_j$. Under a first-seller approach, they would also have an incentive to reduce their emissions because this would reduce their requirement to surrender emissions allowances and thereby lower their cost, just like reducing generation cost.

The incentives under a load-based approach are quite different. The introduction of a load-based program would raise the cost for the LSE if generator i emits CO_2 because in addition to paying a wholesale market price, the LSE would have an allowance cost (a_i). If this facility remained the marginal generator, the effective cost of power for the LSE from this facility would rise to $p^{+} = g_i + a_i$. If the LSE had the ability to send signals into the market to discriminate among bids according to their emissions, then the market would identify a new marginal generator k instead of i if $g_k + a_k < g_i + a_i$, resulting in a new wholesale power price $p' = g_k$. Facilities i and k would have incentives to reduce their emissions, but all other facilities j with $g_j + a_j < g_k + a_k$ would not have an incentive to try to reduce their emissions rate because (a) they would not have compliance responsibility under a load-based approach and (b) reducing their emissions would not change their revenue but presumably would raise their cost. Consequently, inframarginal generators would lack an incentive to achieve emissions reductions.

The differences between the two approaches come into even starker contrast in the context of the ISO's Market Reform and Technology Upgrade initiative, already approved by the Federal Energy Regulatory Commission. One component of this will be the expected introduction of a day-ahead market in 2008 that will attract 10% to 20% of the power provided into the market. The reform moves away from unit-specific contracts and commitments and allows more sophisticated portfolio strategies in the power market. As such, the day-ahead market will erode the "line of sight" between generators and the LSEs because sources that supply into the market will not be identifiable by the entities purchasing from the market. The LSE would submit a schedule of bids for purchase and the ISO would clear the market among offers to sell. This is a fundamental component of the market that leads to efficiency improvements in the ISO's scheduling of the transmission grid.

The consequence is the classic problem of the bad chasing out the good in the day-ahead market. The combination of a load-based cap-and-trade program and the day-ahead market would lead relatively dirty generators to bid into the market to hide the cost of their emissions. Generators in the day-ahead market would lack incentive to reduce emissions because they are not identified and receive no reward for doing so. The only solution would be to separate the ISO day-ahead market into a bunch of different markets, each with different emissions profiles, but this would undermine the advantages of the day-ahead market.

When LSEs buy from the day-ahead market, as opposed to making purchases outside the market, they would buy with a specific anticipated emissions rate. The actual estimation of emissions associated with generation would have to occur ex-post because the actual generation that is scheduled would depend on congestion on the transmission grid and the decisions of the system operator. What happens if sometime later the LSE finds out that a different constituency of generators was actually dispatched by the system operator and the emissions rates deviate from the rates the LSE thought it bought from the market? Litigation may have to determine whether the ISO or the LSE is responsible, and the administrative and legal issues are likely to become complex.

Meanwhile, relatively clean generators would want to avoid the day-ahead market. One would expect to see greater bilateral contracts and self-scheduling among relatively clean generators trying to capture the value of their relatively low emissions rate. The LSE would then submit instructions to the ISO for specific dispatch of facilities under a bilateral contract. This begets another issue. What happens, and which party is liable, when the LSE instructions to the ISO for self-scheduling cannot be fulfilled because of transmission constraints? Is the ISO or the LSE responsible for the unanticipated emissions?

Gillenwater and Breidenich (2007) describe an approach to load-based regulation that would help overcome the problem of imprecise monitoring and impure incentives, at least for power generated in the state, but unfortunately this approach would move the cap-and-trade program away from efficiency in other ways. The authors propose a program that would not require bilateral transactions between generators and LSEs. Generators would produce a tradable certificate for the power they sell onto the grid that would record two measures: the power put onto the grid (MWh) and the emissions (tons CO_2). LSEs would be responsible for acquiring a sufficient number of certificates to cover their sales to customers, and they would be responsible for the emissions that accompany the power sales on their portfolio of certificates. The certificates that an LSE acquires would not necessarily come from generators that provide power to the LSE; they could come from any generator in the program. The LSE would have to pay a premium for certificates with relatively a low emissions profile and would manage a portfolio of certificates such that its emissions cap was achieved.

The certificate approach is elegant in the way that it provides incentives to generators and the LSE. Unfortunately, this approach creates a bad model if the electricity sector is integrated into an economy-wide trading program. The way that power producers earn certificates is through power production, and therefore this is fundamentally an output-based, updating allocation of certificates (Hobbs 2007). Such a program provides an output subsidy to generators that are cleaner than the system average, which leads to expanded production from those facilities and which leads to lower electricity prices. To see this in a simple way, first imagine a program with full auction of allowances (a) at a price p_a, which in general moves positively with the amount of emissions and generation. A facility must buy allowances to cover emissions (e), and its emissions change with production at a marginal rate of $e'(q)$. The marginal generation cost is an increasing function of quantity $(c'(q) > 0)$. The marginal facility will generate where its total variable cost is equal to revenue: $p(q) = c'(q) + e'(q) * p_a$, and the allocation of emissions and generation can be expected to be efficient. Now imagine instead emission allowances were distributed for free using a certificate program. Let the average emission rate under the cap (termed the "default emission rate" by Gillenwater and Breidenich) be $\bar{e}$, such that if all generators produced this amount the cap would be met. Firms are freely allocated certificates at this emission rate times their quantity of output. At the prior level of production by all firms the price of allowances (certificates) would be unchanged. However, the price of electricity would be greater than variable cost: $p(q) > c'(q) + \left(e'(q) - \bar{e}\right) * p_a$, because of the new term on the right hand side $\bar{e} * p_a$ that constitutes a subsidy to production. Consequently, the facility would chose to produce at a level of output equal to $\hat{q} > q$.

Although there is a political virtue to lower electricity prices that would result from an output-based, updating allocation, as noted elsewhere there is a substantial efficiency cost (Burtraw et al. 2001; Fischer 2003). The output subsidy leads to increased generation, with a larger number of MWh chasing the same number of allowances under the cap, which drives up the allowance price. This has two negative consequences. The higher allowance price sends an inaccurate signal to policymakers about the minimum resource costs necessary to achieve emissions reductions. In addition, the effect would be to raise allowance prices for the economy-wide program while subsidizing production of electricity.

Some advocates of the load-based approach have argued that the imprecise monitoring and impure incentives problems do not matter because there is little opportunity for supply-side reductions in emissions. A similar viewpoint was prominent prior to the implementation of the SO_2 trading program as well. At that time, most observers expected that SO_2 emissions reductions would come primarily from the introduction of capital-intensive post-combustion controls (scrubbers). Some switching from high to low sulfur coal was expected. Blending of types coal types was expected to be limited to at most 5% low-sulfur coal in boilers that operated with high-sulfur fuel (Torrens et al. 1992). However, given the incentive to do so, many facilities found ways to reduce emissions without scrubbers. Ellerman et al. (2000) estimate that 63% of emissions reductions in the first three years of the program (1995–1997) were achieved in ways other than scrubbing; this is a careful estimate that accounts for unanticipated changes in relative fuel prices that favored switching to lower-sulfur coal even in the absence of the emissions cap. The primary method to achieve reductions was switching to lower-sulfur coal. In addition, trial and error led to the discovery that fuel blends containing up to 30% to 40% low-sulfur coal were possible without causing a derating of the facility (Burtraw 2000).

Today, many people look to post-combustion controls for CO_2 (carbon capture and geologic sequestration) as the prominent way to achieve large emissions reductions from the electricity sector, but unfortunately, the widespread commercial application of this technology is a ways off. But other types of measures to reduce CO_2 emissions, such as cofiring biomass at coal-fired power plants, are feasible now. Improvements in heat rate (the fuel requirement per unit of electricity generation) and associated reductions in fuel use have been achieved on a slow but ongoing basis for decades and offer continued opportunity. Moreover, fluctuation in heat rates and emissions varies significantly among facilities and depends on how a facility is dispatched, and thus the scheduling of facilities for operation provides another opportunity to harvest low-hanging fruit on a fleet-wide basis. However, under a load-based approach, the incentive to harvest these opportunities to reduce emissions would be eroded because there would be no way to pass the value of emissions reductions to many generators. More importantly, the load-based approach will fail to deliver incentives for technological innovation (Van Horn and Remedios 2007).

In sum, the load-based approach will not be able to send accurate, transparent signals to generators in a general way about the opportunity cost of emissions. This is especially true if the electricity market continues with market reform. The lesson is that it is important to recognize that the vision for the future of the electricity market and the design of a greenhouse gas cap-and-trade program are inherently linked.

3.2.3 Environmental Integrity

The third distinction between the two approaches regards environmental integrity. If there is a CO_2 emissions cap and it is enforced, then one can presume that emissions will fall. However, the two approaches have broad-reaching—and different—implications for the integrity of the institutions that they would create.

If one is going to use a market to address environmental problems, achieving environmental integrity requires integrity in the emissions market: any emissions covered by the cap-and-trade program must be monitored, reported, and verified with a high degree of accuracy. Although both approaches have inherent inaccuracies with respect to imported power, a load-based approach has inaccuracies for all emissions in the market. This threatens to undermine public confidence in the institution of cap-and-trade for greenhouse gas policy in California.

Looking back 15 years, one can note what happened with the SO_2 trading program. At the time, emissions trading was far from popular among environmental advocates. There were cartoons asking, "What's next, the L.A. Police Department trying to buy civil rights credits in Wisconsin?"

Yet a few years later, environmental advocates in Washington were the leading proponents for using cap-and-trade to address a new wave of environmental problems. The SO_2 program brought virtually 100% compliance. Interested parties could look at the web and see electronic reporting of emissions and tracking of allowance ownership. Environmental advocates could see exactly what was happening at specific plants and knew that every plant was incurring an opportunity cost associated with those emissions. That reassured the financial community. Investors knew that if they made an investment to reduce emissions at a specific plant, the value of that investment would not be hidden by averaging of emissions in the market and thereby eroded.

The key element in a market-based policy is to use changes in relative prices to pass to economic decisionmakers, both upstream and downstream, financial responsibility for the environmental consequences of the economic decisions they make. A load-based approached can be criticized in this regard for its lack of transparency and its inability to send those price signals upstream, which has the potential to undermine investor confidence and erode confidence in the emissions market.

The integrity of the emissions market is important, but not because the success of the program should be measured on the basis of the performance of a market. The point of emissions allowance trading is not to trade emissions allowances. The design of the market is important because it can lower the overall cost of achieving emissions reductions. This in turn can lead to savings for households and for business, or it can mean that society can achieve greater emissions reductions for the same cost. However, if California is to use a market to achieve its goals, then it should not want to create a market that is not going to perform as markets are expected to. That would erode confidence in the market and also in the political will to achieve environmental goals.

3.3 Where the Jury Is Still Out

In two general areas—the law and national-level environmental policy—it is difficult to tell whether there is an important difference between a load-based approach and a first-seller approach.

3.3.1 Legal Challenges

The legality of the approaches being considered is one issue that could trump other considerations if one or the other of the approaches were found to violate the law. Two potential legal challenges have been discussed widely. One is the Interstate Commerce Clause, which constrains the state's ability to regulate interstate trade. Specifically, the state cannot treat commerce from inside and outside the state in a different manner to the disadvantage of out-of-state entities.

One way to view the first-seller approach is that it would operate like the proposed low-carbon fuel standard (Farrell and Sperling 2007). All first sellers of electricity would be regulated according to an assumed emissions rate, and sellers would have the opportunity to introduce evidence to the contrary. In fact, for sellers of power generated in California it would be easy to introduce evidence—by reference to the monitoring of emissions from large stationary sources that will be compiled by the California Air Resources Board. For power from out of state, first sellers would have the ability to provide financial information linking power identified on the NERC e-Tag documents with specific generation sources. They could then show the path of financial obligations that is associated with power generation. Conceptually, this is a uniform application of the regulation for sources in state and out of state; whether the law views it in this manner remains to be seen. The load-based and first-seller approaches appear to be in the same boat with respect to how Interstate Commerce Clause issues are interpreted.

The second potential legal challenge has to do with the Federal Power Act, which reserves to the Federal Energy Regulatory Commission the authority to set rules governing transmission of electricity. Some have suggested that the act may render substantive "first seller" obligations unenforceable because it places the state in the position of regulating wholesale power transactions. Others disagree. Either way, some have suggested the state could seek a declaratory order that would explicitly delegate authority to the state or the ISO to regulate transactions in these ways. On this legal issue the uncertainty is greater for the first-seller approach. The load-based approach imposes obligations directly on the load-serving entities and indirectly on wholesale transactions, so it may have greater immunity against a Federal Power Act challenge.

3.3.2 Influencing the Federal Policy Agenda

The Market Advisory Committee articulated the view that the cap-and-trade program was not inconsistent with the state's existing widespread technology and regulatory policies promoting efficiency in electricity end use and low-emitting sources of generation. With these policies already in place, the cap-and-trade program is intended to leave no low-cost emissions reductions behind by providing incentives for all generators in state and out of state to squeeze out the small margins of additional efficiency through heat rate improvements, biomass cofiring, small changes in the dispatch order, or whatever means they may discover.

One function of a cap-and-trade program in California is to add to the momentum for achieving climate policy at the federal level and to propose an architecture that will influence federal policymakers. The Regional Greenhouse Gas Initiative states have clearly done this already with their decision about the initial distribution of emissions allowances with an auction.

What might be the implication of a load-based cap-and-trade program in California? This approach was initially suggested as a matter of necessity, not as a useful model on a national level. If the market were to work poorly, it might impart unfortunate lessons for national policymakers. On the other hand, a powerful impetus for federal action throughout history has been to rationalize the helter-skelter of policies that spring up among the states.

A first-seller approach in California would have the advantage that as California joins with regional efforts as part of the Western Climate Initiative, the approach would segue naturally into a source-based approach on a regional basis. This option would allow California to transition naturally to a regional or national generator-based system.

4 Conclusion

The load-based approach and first-seller approach are two alternative designs for a cap-and-trade program in the electricity sector. They differ in their ability to account for emissions in the state, and this paper argues that a first-seller approach would be a stronger framework. This recommendation takes into account the fact that the California PUC has played a leadership role in portfolio planning, procurement, and efficiency policies. The role for cap-and-trade is simply to leave no low-cost emissions reductions behind. A first-seller approach is much better suited to this purpose.

Three points conclude this argument. First, the organization and vision for the greenhouse gas market and the electricity market are inherently linked. The load-based approach is not consistent with market reform and greater competition in the electricity sector.

Second, the load-based approach may prevail as a way to administer a cap with some flexibility, but it is not a market. It is increasingly flexible, increasingly smart regulation—one can think of it as cap-and-regulate. The reason to adopt a cap-and-trade program has to do with the virtues associated with the market, including administrative simplicity, environmental certainty, and cost reductions. If California is going to use a market-based approach, it should not design a market by compromise. It is important for good market design to keep it simple and transparent. A poorly designed market can lead to poor incentives and poor accountability that can bridge to other sectors and undermine confidence in climate policy. This raises the question whether it is worth the trouble and risk of embracing the idea as though it were a market.

Finally, from a statewide and national perspective, it is important to resist the parochial view that allowance value should be kept in the electricity sector. Keeping it in the electricity sector and subsidizing electricity consumption will cause marginal costs to differ across the economy, raise total costs across the economy, and undermine the environmental initiative. In designing its program, California has an opportunity to take a broader, longer-term view and set a progressive example that one can hope would influence national policy.

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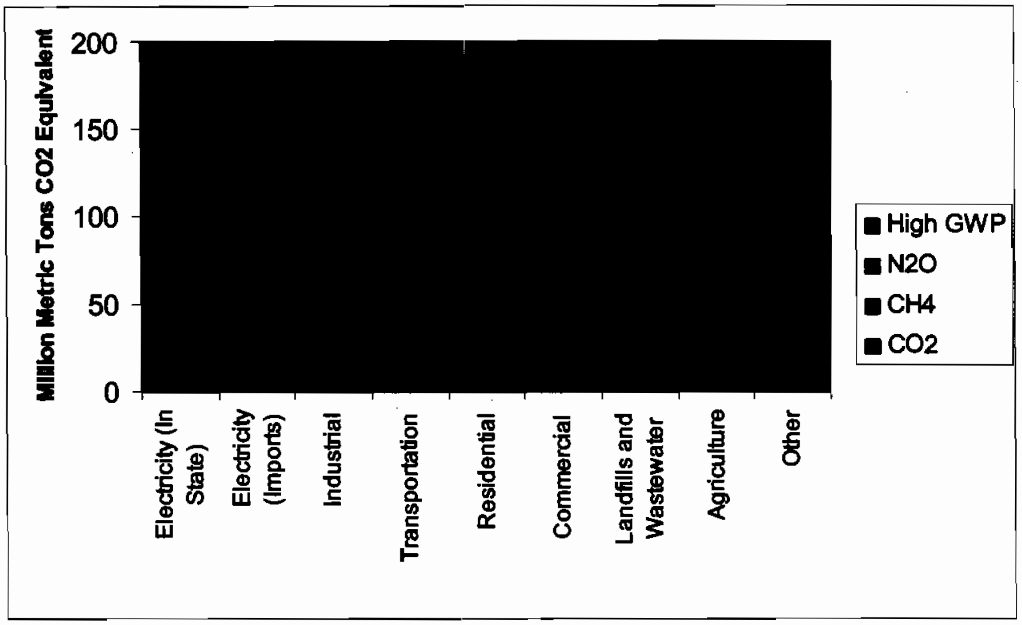
Figure 1. California emissions of greenhouse gases, 2004



Source: California Market Advisory Committee, 2007

Figure 2. Potential points of compliance in the electricity sector

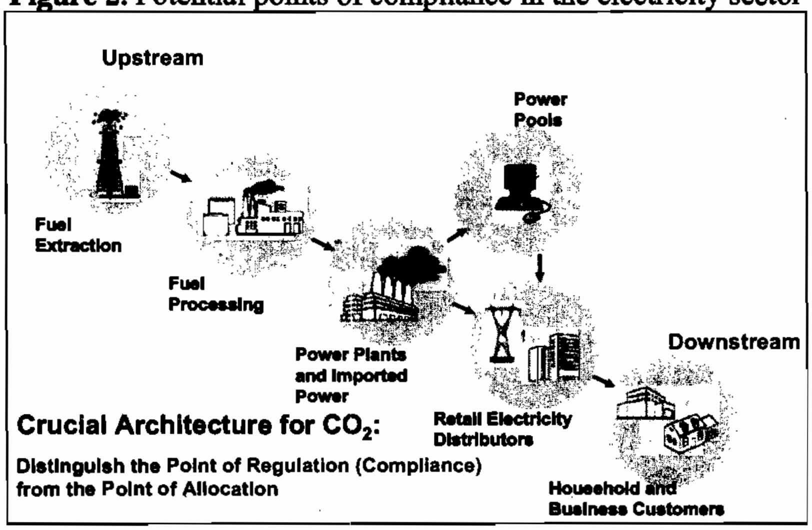
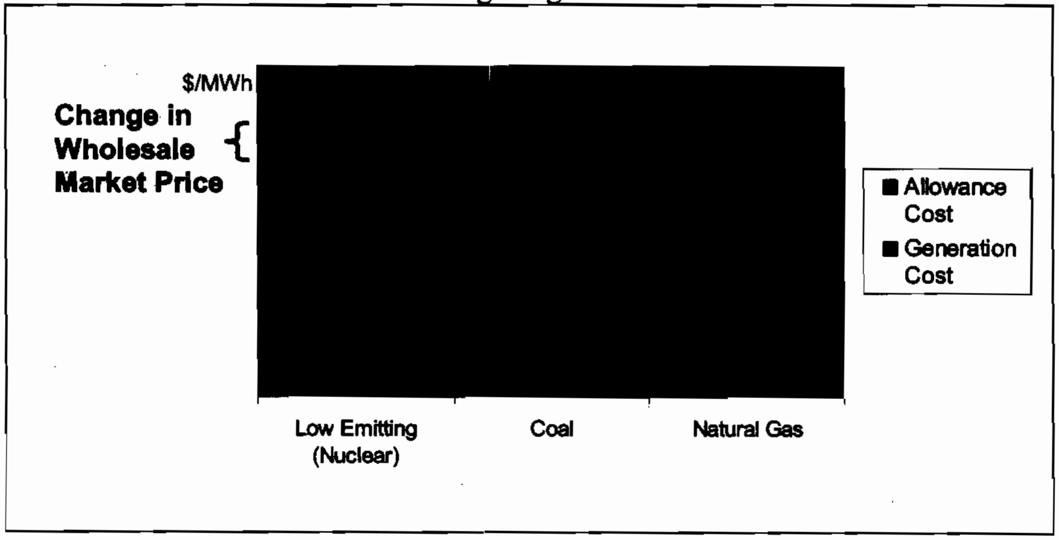


Figure 3. Wholesale power price in competitive market as determined by variable costs of marginal generator



Attachment C

Opinion on "Load-Based and Source-Based Trading of Carbon Dioxide in California"

by

Frank A. Wolak, Chairman
James Bushnell, Member
Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO

November 27, 2007

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1. Introduction

California Assembly Bill 32, the "The Global Warming Solutions Act of 2006", established a goal of reducing the state's greenhouse gas (GHG) emissions to 1990 levels by the year 2020. The California Air Resources Board (CARB) is charged with developing the necessary measures to achieve that target. CARB is cooperating with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to evaluate alternative mechanisms for achieving that goal in the electricity sector. On November 9, 2007, the Administrative Law Judges in the CPUC-CEC joint proceeding on GHG issues[1] issued a ruling requesting comments on issues relating to the type of greenhouse gas regulation that should be applied to the California electricity supply industry.

This opinion responds to that request. The Market Surveillance Committee (MSC) has previously been involved in discussions of the development of GHG policies for the power sector. In particular, the MSC held a meeting at CARB's offices in Sacramento on June 8, 2007 to discuss the interaction of GHG policies and short-term electricity markets in the western United States (US) and the impact of GHG policies on procurement by the state's load-serving entities (LSEs) and other, non-LSE retail providers of electricity, such as municipal utilities, which we will refer to generically as LSEs. In this opinion, we only address a subset of the questions in the ALJs' Ruling, emphasizing the question of the point of compliance with a state-imposed GHG emissions cap. In particular, we address the economic efficiency implications for the California electricity market of alternative points of compliance.

There are essentially four broad alternatives for implementation of AB 32 within the California electric sector. The first is to regulate emissions by placing a reporting and compliance obligation on LSEs. Under this "load-based" approach, LSEs would have to demonstrate that the power they have purchased represents a mix of sources that achieves a specified target, either in terms of tons per year or in terms of carbon intensity.[2] The second is to implement a "pure" source-based cap and trade system similar to other cap-and-trade systems in other parts of the

[1] Administrative Law Judges' Ruling Requesting Comments On Type And Point Of Regulation Issues, dated November 9, 2007 , issued by ALJ Charlotte F. TerKeurst (CPUC) and ALJ Jonathan Lakritz (CEC) in CPUC R.06-09-004 and CEC Docket No. 07-OIIP-01 (the ALJs' Ruling).

[2] Because electricity in a looped transmission network flows according to the laws of physics, it is physically impossible to determine the GHG emissions caused by each MWh of electricity consumed by each load-serving entity. For this reason, a load-based system must use an administrative procedure to assign GHG emissions to each MWh of electricity consumed in California.

world.[3] A third approach would be to implement some hybrid cap-and-trade system that would effectively act like a source-based program for plants within the state, but still try to capture the emissions impact of imports in some fashion. The "first-seller" approach is the most widely discussed of this general hybrid concept.[4] The last alternative would be to focus AB 32 implementation efforts on mechanisms other than cap-and-trade. In that case, California's participation in a cap-and-trade system would be implemented in concert with a regional or federal program, rather than preceding it.

A choice between these approaches should take into consideration various economic and environmental goals. These include efficiency of system dispatch and the performance of wholesale and retail electricity markets, the efficiency of investment in new generation facilities and energy efficiency technologies, consumer costs, administrative simplicity, and effectiveness in achieving the GHG reduction goals set forth in AB32. Because GHGs are global pollutants, perhaps the most important consideration is compatibility with possible west-wide or federal GHG regulations that might be adopted in the near future. Even if California were to reduce its GHG emissions by, say, half, this would reduce world GHG emission by less than one percent. Consequently, a key measure of the success of any state-level GHG emissions regulation is the extent to which other states and jurisdictions adopt it.

While we believe that there are advantages and disadvantages to each of the approaches described above, in this opinion we wish to emphasize two points. First, an often-claimed advantage of the load-based and hybrid approaches–that they regulate the GHG content of imported electricity–is grossly overstated. Although firms would not be able to avoid compliance by physically moving their sources of production out of the State ("leakage"), they would be able achieve much the same ends by "reshuffling" their purchases of imported energy to originate from clean sources.[5] In fact, reshuffling is in many ways a less costly strategy for circumventing environmental regulation than is leakage.[6]

The second point that we wish to emphasize is that the first option, a load-based cap-and-trade system, is clearly and substantially inferior to the other options. We believe that the load- and source-based approaches are similar in some respects, but that the load-based approach is

[3] A source-based approach places compliance responsibility on the facility that is emitting the pollution (the source). In a source-based system each facility would need to acquire emissions permits to offset their total emissions.

[4] A first seller is an entity that first brings power into the California market. All generation units located in the California ISO control area are first sellers of electricity. So in this sense, the first-seller approach is a source-based approach because it is straightforward to determine the GHG emissions per MWh of energy produced from the technical operating characteristics of the in-state generation unit. However, for imports of electricity, the first seller is the entity importing the power into the state. In this case, an administrative procedure must be designed to assign a GHG emissions rate per MWh of energy imported into California for each importing entity. In this sense, the first-seller approach functions like a load-based mechanism because there is no unambiguous method to determine the GHG emissions caused by the electricity sales into California.

[5] Several options for mitigating reshuffling have been raised, but they remain among the most controversial and legally vulnerable aspects of the overall cap-and-trade design.

[6] With leakage, firms have to physically change the sources of production from whatever they were before the environmental regulation took effect. Assuming that firms were buying power from the cheapest sources, changing the mix of generation would have to involve increasing costs. Under reshuffling there could be *no* change in the mix of generation at all, only a realignment of the transactions that define who is buying power from which source.

distinctly inferior in others.[7] In particular, we argue that the two systems are essentially the same on the issues of determining the GHG content of power imports and incentives for investments in energy efficiency and renewable energy. However, in terms of administrative complexity, adverse impacts on the efficiency and costs of dispatching generation units to meet load in California energy and ancillary services markets, and compatibility with likely federal GHG legislation, a load-based system has serious disadvantages compared to any of the other options. Contrary to some claims, we believe that resulting cost of energy to consumers would likely be *higher* under a load-based cap. We discuss each of these issues below. The Appendix summarizes a simple model that demonstrates the equivalence of the two systems in terms of total cost of energy to final consumers–under assumptions that ignore the potential higher consumer costs of a load-based approach due to inefficient generator dispatch in the California day-ahead and real-time markets.

2. The Issues of Imports and Compatibility with Federal Legislation

All options face the same challenge in achieving the goal of reducing total GHG emissions from sources that serve California's electricity demand. The California market is embedded in the much larger western North American market. When only a subset of loads or generation units in this larger market are subject to regulation, a local GHG emissions reduction goal can be frustrated by increases in imports and thus unregulated GHG emissions from elsewhere in the larger market. This has been an issue with state-level regulation of GHG elsewhere in the U.S.[8]

Further, efforts to prevent increased imports from unregulated regions (GHG "leakage") or to incent emissions reductions elsewhere in the west by identifying sources of power for imports and their emissions are likely to be ineffective, regardless of the administrative procedures used to identify specific generation sources. This is because the depth of the west-wide market and the amount of "clean" generation available is such that there is likely to be more than enough clean generation that can be assigned, on paper, to California imports, without actually changing system operations, or investment, in the west. This has been called the "contract shuffling" problem.[9] Markets for electric power will tend to identify and use the cheapest sources of electricity; prohibiting or penalizing imports that, in name, are connected with dirtier sources are unlikely to result in their being dispatched differently, if they are indeed the cheapest power source in the region not subject to GHG limits. Consequently, any policy—load-based or source-based—that addresses only California emissions, or attempts to prevent leakage by administrative procedures

[7]See D. Burtraw, "State Efforts to Cap the Commons: Regulating Sources or Consumers," Resources for the Future, Nov. 9, 2007 for a related and, in some cases, more extended discussion of several of these issues.

[8]For instance, it has been estimated that all of the nominal CO_2 emissions reductions that would occur by expanding the eastern states' Regional Greenhouse Gas Initiative to Maryland would be offset by greater CO_2 emissions elsewhere in the Eastern Interconnection. However, interactions with non-Eastern markets through emissions allowances markets together with purchases of non-power emissions offsets means that the net effect of Maryland joining RGGI is an overall decrease in emissions. (See University of Maryland, Resources for the Future, The Johns Hopkins University, and Towson University, *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, Submitted to the Maryland Dept. of Environment, http://cier.umd.edu/RGGI/documents/UMD_RGGI_STUDY_FINAL.pdf, Jan. 2007, Section 9.3.3.)

[9]J. Bushnell, C. Peterman, and C. Wolfram, "California's Greenhouse Gas Policies: Local Solutions to a Global Problem?" CSEM Working Paper 166, University of California Energy Institute, April 2007.

that identify sources of imports, is very likely to have its environmental goals frustrated by the inability of a California-only policy to alter operations or investment decisions elsewhere in the western North American market.[10]

This conclusion means that a fully effective GHG policy for the electric sector must cover the bulk of the western US market. This implies that a California policy under AB32 should be viewed as an initial step, and that a major goal of that policy should be to facilitate the establishment and implementation of federal or other west-wide policies, rather than to act as an obstacle to such policies. Precedent, as well as the preponderance of proposed federal legislation, indicates that source-based trading of emissions allowances will likely be the basis of any federal regulation of power sector GHG emissions.[11] The emissions accounting and other mechanisms associated with a California load-based system would, at best, be sunk costs that would be abandoned if a federal source-based GHG trading system is adopted. At worst, the existence of an incompatible state-level system could delay or increase the cost of implementing the federal system.

3. The Relative Cost of Load-Based and Source-Based Trading Systems

Another way in which load-based and source-based systems are similar is in the resulting cost of energy to consumers. Experience in the European Union with CO_2 trading in the power sector has shown that high prices for CO_2 translate into higher prices of electricity, and that many generators enjoy the benefits of increased revenues.[12] Arguments have been made that a load-based system would avoid these problems in California, at significantly less expense, in terms of consumer payments, than would a source-based system that achieves the same level of total GHG emissions.[13]

These arguments are incorrect. Even assuming that the same generation sources are used to serve demand under both systems, we demonstrate in the Appendix that a source-based system in which LSEs sign contracts with individual generators to minimize the cost of serving load, while meeting a GHG constraint, results in the *same* cost to load as a source-based system in which generators maximize profit, subject to a cap-and-trade system for GHGs, with the same constraint. This conclusion assumes that, in the latter system, consumers will be allocated all

[10] An effective change in dispatch or investment in western markets not subject to GHG regulation, or the prevention of leakage via increased imports, might be accomplished by a significant regulatory intervention. For example, credit for clean generation outside of California might only be granted to new renewable generation investments that are not counted towards any state's renewable portfolio generation; such investment would be unlikely to have occurred otherwise, and so would represent a real change in system investment and operations outside of California. However, such rules would represent a significant regulatory intervention in market processes, and the emission benefits could arguably have accomplished at less cost through more ambitious renewable energy goals without a cap-and-trade system for GHG emissions.

[11]These precedents include the federal SO_2 and NO_x trading systems under Title IV of the Clean Air Act Amendments, the NO_x SIP call, and, most recently, the Clean Air Interstate Rule.

[12] J.P.M. Sijm, K. Neuhoff, and Y.Chen, "CO_2 Cost Pass Through and Windfall Profits in the Power Sector," *Climate Policy*, Vol 5, No. 1, 2006, pp. 49-72.

[13] See for instance, Synapse Energy, "Exploration of Costs for Load Side and Supply Side Carbon Caps for California", Joint *En Banc* Hearing of PUC and CEC on Point of Regulation in the Electricity Sector (R.06-04-009), August 21, 2007, available at www.synapse-energy.com (accessed Nov. 16, 2007).

emissions allowances, which they then can sell to generators. However, as we argue in Section 5 below, we believe that the perverse incentives created by regulatory efforts to assign the emissions of specific sources to LSEs will lead to the deployment of a less efficient generation mix to serve demand. Overall, this would result in the load-based system leading to higher, *not* lower, energy cost to consumers.

The higher wholesale electricity profits that result from implementation of a GHG trading system, whether load-based or source-based, have at least two possible sources. One is the value of the emissions allowances themselves ("the allowance rents"), which is the allowance price times the number of allowances. If allowances are given for free to generators, this value increases generator profits. On the other hand, if allowances are given to load, and then sold to generators (perhaps via an auction) for use in a source-based system, with the proceeds returned to consumers, then these rents will, to some extent, offset the price increases resulting from the cap-and-trade mechanism. These rents are also retained by consumers under a load-based system.

The other possible source of higher profits resulting from GHG emission permit trading is what might be called the "rents of clean generation." In a source-based system, generation units with low emissions will benefit from higher energy prices because the price increases will exceed the expense of allowances. The entire industry will benefit, on average, if the average emissions rate for all generation units is less than the marginal emissions rate that causes the price increase. This profit is retained by generation unit owners in both source-based and load-based systems. This is because, in load-based systems, as the Appendix shows, LSEs will pay more for electricity from cleaner generators, because that generation is more effective in helping the LSEs meet their emissions constraint. In a competitive market, the difference in prices that LSEs would pay to different generation units will equal the difference in their emissions rates times the implicit cost of emissions to the LSE. It turns out that this implicit cost will be the same as the price of allowances in a source-based system with the same GHG target.

If this clean generation is independently owned, the "rents to clean generation" would be retained by generators under either load- or source-based systems. However, within California, a significant fraction of this generation is owned by utilities, so any such additional profits to those plants could be returned to consumers. Meanwhile, the portion of those rents accruing to new renewable sources, given effective competition in that sector, would translate into lower subsidies from LSEs under California's renewable portfolio standard (e.g., lower renewable energy credit prices), also resulting in a return of some of those rents to consumers. These returns of "rents to clean generation" would not be affected by the existence of a load-based or source-based system.

Therefore, under an assumption of comparable production sources under the two systems, the load-based system yields no advantages in costs over a source-based system (with allowances owned by consumers). This is because consumers would, in both cases, retain the allowance rents as well as the portion of rents to clean generation that accrue to utility-owned and new renewable generation. However, if the load-based system leads to a distortion of the mix of production sources, it would yield higher costs than a source-based system.

4. Impact on LSE Incentives for Energy Efficiency and Renewable Energy

It has sometimes been argued that a load-based system will result in a greater incentive for LSE investments in energy efficiency and renewable technology than a source-based system. The argument is that the load-based system "paints a target on the back" of the LSE, making it more accountable for its carbon footprint. This effect is speculative, and we doubt that it would be significantly different from the incentives provided by source-based regulation, for the following reasons.

First, California investor-owned utilities are already subject to an extensive regulatory system that arguably provides more incentives than any other state for investment in energy efficiency and renewables. These incentives include procurement priorities that place efficiency at the top of the list among all resources; a charge on all California electricity consumers to fund cost-effective energy efficiency programs; the decoupling of utility revenues from sales; and the rate-of-return incentives adopted by the CPUC in September 2007. With implementation of AB32, carbon costs will be included as part of the "avoided energy costs" in the "Total Resource Cost Test" used to identify beneficial efficiency programs under California's rules; as a result, more energy efficiency programs will become cost-effective. This will be true under either load- or source-based programs.[14] California's many regulatory incentives will then motivate the state's utilities to pursue many, if not most, of those opportunities. We see no reason why California's regulated utilities will be more likely to pursue these newly cost-effective programs under one emissions regulatory system than another.

Second, California's LSEs are being required to account for and report the GHG emissions associated with their contracts no matter what sort of GHG regulatory system is implemented under AB32. There will be public visibility and pressure to pursue energy efficiency to lower emissions under either load-based or source-based systems.

Third, California already has ambitious renewable energy goals for its LSEs. It seems unlikely to us that a load-based trading scheme would motivate LSEs to exceed the 20% renewable goal for 2010..

5. Using the California ISO Markets to Enhance GHG Regulation

An important way in which load-based and source-based systems differ is in how they interact with the new markets that are to start operation next year under the ISO Market Redesign and Technology Upgrade (MRTU).[15] Under the MRTU design, the ISO's new day-ahead market will perform two functions in an integrated manner:

(1) provide a market for wholesale buyers and sellers to transact, and
(2) schedule the use of the transmission grid to deliver energy to consumers.

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[14]The Appendix provides an example the equivalence of avoided energy costs under load- and source-based systems.

[15]Note that the concerns we express in this section about the load-based system would also arise if, instead, GHG trading were to be implemented under the present California ISO markets or, indeed, under any real-time or day-ahead market that mixes different sources of power.

In contrast, under today's market structure, these two functions are separated, so that participants can only schedule their use of the transmission grid, but cannot engage in energy trading through a formal day-ahead market. To maximize the benefits that market participants will receive from the integrated day-ahead market that will exist under MRTU, they must submit "economic bids" to this market; that is, specific quantities of energy they want to buy or sell at specific prices, rather than "self-scheduling" all or the great majority of their energy by submitting only their desired quantities without prices. As the volume of self-schedules relative to economic bids increases, the efficiency of the economic dispatch declines, and this is the main concern about how the choice of GHG regime interacts with the ISO markets. As we explain below, the load-based approach will encourage self-scheduling in conflict with the efficiency potential of the MRTU markets, whereas the source-based approach will encourage economic bidding, thus utilizing MRTU's new economic dispatch in concert with GHG regulation to achieve the desired environmental objectives.

As pointed out in the previous section, LSEs will pay cleaner generation a higher price than high-emissions generators in a power market that is subject to a load-based GHG compliance mechanism. Such a market is incompatible with the ISO day-ahead and real-time markets for energy and ancillary services, because MRTU will make no distinction between generation units having different emission rates in its bidding and dispatch processes. It will not be possible for the ISO to define, for example, different locational marginal prices (LMPs) for dirty and clean power at each bus, or to explicitly consider relative emissions rates in deciding what units will be chosen to provide, say, spinning reserves or residual unit commitment services. MRTU will not be able to accommodate demand bids that express a higher willingness to pay for low emissions power. Power and ancillary services from various sources with various emissions rates will be inextricably mingled within the ISO markets. The best that can be done is to calculate an average or marginal emissions rate associated with ISO power delivered at different times and locations.

That the California ISO markets will not differentiate sources of power by their emissions is a problem only with load-based systems where LSEs must track the emissions associated with different sources of power. By contrast, in a source-based system, compliance is at the point of production, and the opportunity cost of allowances is internalized into the bids submitted by suppliers to the ISO markets. Efficient compliance with emissions caps can then be attained, without complicating the ISO markets.

We believe that a load-based system, in which LSEs must track, using a pre-specified administrative procedure, the emissions associated with all their energy transactions, will pose a grave danger to the efficiency and competitiveness of the California short-run markets. This is because LSEs participating in ISO markets will be buying power, and generators will sell power in the ISO markets based on some average or marginal emissions rate that is administratively determined. As a result, generation unit owners that can command a premium for their units in the bilateral market, because of the unit's low emissions, will selectively avoid providing bids to the ISO markets, leaving just the high emission generation units willing to accept the ISO prices, which would reflect average emissions. In this sense the "dirty" generation would chase out the "clean."[16] Low emission sources will tend to self-schedule, in order to secure higher prices. Another reason why more self-scheduling is likely to occur is because each LSE will be trying to self-manage its supply portfolio to stay within their emissions limitation. Assuming that compliance will be based on actual output, as opposed to contracted supply, LSEs will seek to protect their portfolio from being re-dispatched in the ISO markets, by submitting self-schedules.

As a result, the amount of market bids that the ISO will have available to manage congestion and to optimize total system dispatch will be severely limited. The ISO markets for energy and ancillary services will become significantly thinner. For instance, hydropower, which has zero GHG emissions, would likely be less willing to provide spinning reserve to the ISO because it would not want to earn the (relatively) low energy prices it would gain if it is dispatched in the ISO's markets, thereby giving up more lucrative "clean" energy prices in the bilateral market. Likewise, highly efficient combined cycle units would be less likely to bid into the ISO's real-time markets. Having less resources available for real-time system operation would increase costs for the ISO for any redispatch that must occur between day-ahead and real-time to manage congestion, to accommodate demand forecast errors, and to adjust for unexpected equipment failures. With fewer resources bid into the ISO markets, the likelihood of schedule curtailment would increase, as would the stress on system operators as they try to keep the system balanced. Furthermore, thinner markets would likely also be less competitive markets. Ultimately, all of these increased costs would be passed on to consumers.

Thus, a load-based system would conflict with the goal of more competitive energy and ancillary services markets in California, and with the goal of creating liquid and deep markets day-ahead and in real-time in order to lower operation system costs and maximize the ability of the ISO operators manage unforeseen contingencies.[17] In contrast, a source-based policy and MRTU would work together to lower the costs of meeting GHG goals and California's need for power.

It is important to recognize that the problems created by a bias against pool-based markets grow larger as the geographic scope of a load-based cap-and-trade system grows. Although the environmental regulatory problem that motivates the load-based scheme (i.e. regulating imports) grows less significant as more states participate, the *economic* consequences of the environmental regulation can grow more serious. Many recognize that the western market is cur-

[16]This is, in a very general way, analogous to the infamous "dec" game in zonal power markets, in which intrazonal congestion was ignored day-ahead, but resolved in real-time by "inc"ing costly generation in load pockets and allowing cheaper generation in generation-rich areas to buy out of their day-ahead commitment at a low price. The result was that day-ahead markets would receive an excess of undesirable generation (from generation-rich areas) while the most desirable generation (in load pockets) would stay away, awaiting higher prices in real-time. This increased congestion and consumer costs.

[17]The difficulties that arise in the ISO MRTU markets if power and emissions attributes are bundled in a load-based system can be avoided if emissions attributes are unbundled and traded separately between generators and LSEs (see M. Gillenwater and C. Breidenich, "Internalizing Carbon Costs in Electricity Markets: Using Certificates in a Load-Based Emissions Trading Scheme," Unpublished manuscript, Science Technology and Environmental Policy Program, Princeton University, Princeton, NJ). However, that unbundling proposal can be shown elsewhere to be economically equivalent to source-based trading of allowances with allowances allocated free to generators according to their sales; see Section A.5 of the Appendix. Such a system would be costly to consumers, while being more complex to administer than a source-based system.

rently a patchwork of less than ideally coordinated trading rules and protocols. Overcoming these "seams" issues continues to be an important concern. By creating an institutionalized bias against pool-based markets, the west could be turning its back on the opportunity to better unify its regional markets for energy and GHG emissions permits.[18]

6. Concluding Comments

Our recommendation against adopting a load-based program for regulating the emissions of greenhouse gases associated with electricity consumption in California should not be interpreted as implying that we necessarily favor the immediate implementation of source-based trading in the state. The very likely advent of federal GHG regulation in the next few years means that there are advantages to deferring implementation of a formal trading system in California until the form of federal regulation becomes clear. Given the ambitiousness of California's existing renewable energy and energy efficiency programs, we believe that most of the GHG reductions that would be achieved in the power sector under an emissions cap (either load-based or source-based) would likely result from those programs in any event. We believe that it is crucial that a level playing field ultimately be established that would reward all measures for reducing CO_2, because measures such as improving the efficiency of fossil-fuel power plants might be cost-competitive with investments in renewables and energy efficiency. However, because California's dependency on imported power raises doubts about the environmental integrity of a California-only GHG trading system, it is difficult to justify the cost of establishing a sophisticated trading system (either load-based or primarily source-based) that might be abandoned quickly in the face of federal preemption.

If it is decided that regulation of the GHG emissions of the California power sector should proceed immediately, despite these concerns, we strongly recommend that a source-based system be implemented, rather than a load-based system. We conclude that a load-based system, rather than lowering energy costs to California consumers relative to a source-based system, would likely result in higher costs. At best, the load-based system is no less expensive to consumers than the source-based approach, if both result in efficient dispatch and emissions allowances are allocated to LSEs. However, the load-based approach poses significant risk to dispatch efficiency by discouraging cleaner sources from submitting bids the California ISO's day-ahead and real-time markets, thereby decreasing the flexibility and competitiveness of those markets. In contrast, a source-based system utilizes those markets to help achieve the GHG policy objectives more effectively and efficiently.

Therefore, the speculative benefits of a load-based system, in terms of possibly greater incentives for energy efficiency or renewables, cannot be justified in light of the additional administrative complexity and cost of such a system, the threat that it would pose to the competi-

[18] This is not just an academic question. Research on the expansion of the PJM market has demonstrated a significant change in the operations of power plants in the eastern U.S. (see E. Mansur and M. White, "Market Organization and Efficiency in Electricity Markets", Working Paper, April 2007 (http://www.som.yale.edu/faculty/etm7/papers/mansur_white_pjmaep.pdf). It appears that the previous wholesale market regime, which is comparable to much of the western U.S. today, was not taking full advantage of the efficiencies offered by the network. Increased efficiency can produce both economic and environmental benefits.

tiveness and efficiency of the ISO-administered markets under MRTU, and the additional difficulties that would arise when transition to a federal cap-and-trade system would occur.

Technical Appendix[19]

This Appendix provides a demonstration of the general result described in Section 3: that a load-based system results in the same consumer costs as a source-based system in which allowances are sold by consumers to generators. This demonstration is based on simplified models of the power and emissions markets under load- and source-based policies (Sections A.1 and A.2), followed by an analysis of their general properties (Section A.3). A numerical example is then given that illustrates the principle (Section A.4). That example also illustrates the equivalence of avoided costs (for use in the "Total Resource Cost" benefit-cost test for energy efficiency programs in California) under the two policies. Finally, in Section A.5, we show the economic equivalence to source-based trading of the Gillenwater and Breidenich (2007) (*op. cit.*) proposal to unbundled emissions attributes from power in a load-based system, pointing out that it involves significant subsidies of producers.

A.1 Model of a Load-Based Equilibrium

The model for a load-based system consists of models of consumer and supplier decision making, which combined with a market clearing condition defines the market equilibrium. The consumer model includes a constraint on the emissions resulting from the consumer's portfolio of supply contracts.

Consumer Model: One single LSE serving the market is assumed; this model can be readily generalized to multiple LSEs, and the fundamental results do not change. The single LSE acts as a price taker with respect to the price of electricity (i.e., does not exercise unilateral market power).

x_{Li} = MW purchases from supplier i by the LSE in the load-based equilibrium
p_{Li} = \$/MWh price paid (assumed fixed by LSE) for power from supplier i in the load-based equilibrium
E_i = ton/MWh emissions rate for supplier i
L = MW load for LSE (a single hour is assumed for simplicity)
K = tons/MWh emission cap for load

The model is:

MAX -Expenditures = $-\Sigma_i\, p_{Li}\, x_{Li}$
subject to:
$\Sigma_i\, E_i\, x_{Li} \leq K\, L$ (shadow price α_L)
$\Sigma_i\, x_{Li} = L$ (shadow price β_L)
$x_{Li} \geq 0$ all i

[19] The model discussed in this memo is an elaboration of models in B.F. Hobbs, "An Analysis of the Breidenich/Gillenwater Proposal for Load-based Trading of CO_2 rights," Unpublished manuscript, The Johns Hopkins University, June 7, 2007, and in Y. Chen and A. Liu, "Economic and Emissions Implications of Load-based, Source-based, and First-seller Emissions Trading Programs under the California AB32", Draft, University of California Merced, November 2007.

That is, the LSE minimizes the cost of meeting power demand and the emissions constraint by choosing which suppliers to buy power from. (The objective is phrased as a maximization so that the dual variable of the emissions constraint is nonnegative.)

Producer Model: There is one plant per producer, with a constant marginal cost and a fixed capacity. Each producer is a price taker.

y_{Li} = MW sales from producer i to LSE
C_i = \$/MWh marginal cost of production for producer i
CAP_{Li} = MW generation capacity for producer i

The producer's problem is:

$$\text{MAX } \text{profit}_{Li} = (p_{Li} - C_i)y_{Li}$$

subject to:

$y_{Li} \leq CAP_i$ (shadow price μ_{Li})
$y_{Li} \geq 0$ all j

Market Clearing: This ensures that supply and demand for energy from each producer are equal, and mathematically generates the market clearing price.

$x_{Li} = y_{Li}$ for all i (shadow price p_{Li})

Equilibrium Model: The equilibrium model consists of the first-order conditions for each of the market participant's optimization problems (Kuhn-Tucker conditions) together with the market clearing conditions, yielding a "square" system (as many conditions as unknowns). The unknowns are $\{x_{Li}, y_{Li}, p_{Li}, \alpha_L, \beta_L, \mu_{Li}\}$. It can be shown that low emission producers get a premium for their power representing the value to LSEs for meeting the emissions constraint. Furthermore, if there is more than one LSE, each LSE will pay the same price for power from a given producer (of course, transmission constraints are disregarded).

A.2 Model of a Source-Based Equilibrium

Notation for this model is the same as for the load-based equilibrium, except that the sub-script "S" is substituted for "L" on all variables.

Consumer Model: The model for consumers is a simplified version of the load-based model:

$$\text{MAX } \text{-Expenditures} = -\Sigma_i\, p_{Si}\, x_{Si}$$

Subject to:

$\Sigma_i\, x_{Si} = L$ (shadow price β_S)
$x_{Si} \geq 0$ all i

Producer Model: This model differs from the load based one because it includes the expense of allowances in the profit function.

$$\text{MAX profit}_{Si} = (p_{Si} - C_i - \alpha_S E_i) y_{Si}$$

Subject to:

$y_{Si} \leq CAP_i$ (shadow price μ_{Si})
$y_{Si} \geq 0$ all j

Market Clearing Condition:

$x_{Si} = y_{Si}$ for all i (shadow price p_{Si})
$\Sigma_i E_i y_{Si} \leq K L$ (nonnegative shadow price α_S)

The emissions price can be positive only if the emissions constraint is binding. The total amount of allowances is assumed for the sake of comparison to be the same as the sum of maximum emissions by the LSEs under the load-based model.

Equilibrium Model: The equilibrium model consists of the first-order conditions for each of the market participant's optimization problems (Kuhn-Tucker conditions) together with the market clearing conditions, yielding a "square" system (as many conditions as unknowns). The unknowns are $\{x_{Si}, y_{Si}, p_{Si}, \alpha_S, \beta_S, \mu_{Si}\}$. It can be shown that energy prices p_{Si} paid to all producers i are equal (unlike the load-based case).

A.3 Theoretical Equivalence of the Models

Results for the relationship of the two models can be shown as follows.

The first set of results concerns the relationship between the equilibrium values of the price and quantity variables:

$p_{Li} = p_{Si} - \alpha_S E_i$ for all producers i
$\{x_{Li}, y_{Li}, \alpha_L, \beta_L, \mu_{Li}\} = \{x_{Si}, y_{Si}, \alpha_S, \beta_S, \mu_{Si}\}$

That is, the load-based price for energy from a producer equals the source based price minus a penalty for its emissions. This penalty is the per ton shadow price of emissions (which is implicit in the LSE's maximization problem) times the emissions rate. This result is shown in two steps. The first step is to substitute in the source-based equivalents for the load-based variables in the load-based equilibrium conditions, and showing that the source-based variables satisfy those equilibrium conditions. The second step is to go the other way: substitute $p_{Li} + \alpha_S E_i$ for p_{Si}, and $\{x_{Li}, y_{Li}, \alpha_L, \beta_L, \mu_{Li}\}$ for $\{x_{Si}, y_{Si}, \alpha_S, \beta_S, \mu_{Si}\}$ in the source-based equilibrium conditions; it turns out that the load-based variables satisfy those conditions. Thus, prices (adjusted for emissions in the case of energy prices) and the quantities for the load-based equilibrium and source-based equilibrium are the same. (More generally, if the equilibrium for one of the models is not unique, then this is also true for the other model, and each solution to one has an equivalent solution to the other.)

The second set of results concern the equivalence of the consumer payments under the two systems. In particular, because $p_{Li} = p_{Si} - \alpha_S E_i$, the consumer payments minus allowance rents (assumed to accrue to consumers) under the source-based system equal the consumer payments under the load-based system. The demonstration is as follows:

Source-based energy payments minus allowance rent

$$= \Sigma_i p_{Si} x_{Si} - \alpha_S K L = \Sigma_i p_{Si} x_{Si} - \alpha_S \Sigma_i E_i y_{Si} = \Sigma_i (p_{Si} - \alpha_S E_i) x_{Si}$$
$$= \Sigma_i (p_{Li}) x_{Li} = \text{Load-based energy payments}$$

The second step is true even if the emissions constraint is not binding, because $\alpha_S = 0$ in that case.

By the same logic, it can be shown that generator profits are the same under a load-based or source-based system, assuming that under the latter consumers are allocated the allowances initially, and sell them to producers. Thus, the "Rents to Clean Generation" that generators earn in the source-based system are also retained by generators in the load-based system. An assumption that load would gain those rents under the load-based system is incorrect.

A.4. Numerical Example

Consider an isolated power system (no imports) in which there are two load serving entities (1 and 2) three generation companies each with different types of generation: A,B, and C.

- The load serving entity has constant load L = 2000 MW. Under the load-based system, it is obliged to buy power contracts that, on average, have an emissions rate of 0.55 tons/MWh.
- Generation type A has emissions E_A of 0 tons/MWh, marginal cost C_A = 0\$/MWh (wind or hydro), and capacity CAP_A = 500 MW.
- Generation type B has emissions E_B of 0.6 tons/MWh, marginal cost C_B = 80\$/MWh (wind or hydro), and ample capacity CAP_B (no limit).
- Generation type C has emissions E_C of 1 ton/MWh, marginal cost C_C = 40\$/MWh (wind or hydro), and ample capacity CAP_C (no limit).

The solution to the load-based equilibrium model from Section A.1 results in the following generation, cost, and prices:

- MW generation y_{Li} from companies i=A,B,C: y_{LA} = 500 MW, y_{LB} = 1000 MW, y_{LC} = 500 MW. These also equal MW purchases by the LSE (x_{LA}, x_{LB}, and x_{LC}, respectively).
- Prices p_{Li} paid by the LSE for each type of generation i=A,B,C: p_{LA} = \$140/MWh; p_{LB} = \$80/MWh; p_{LC} = \$40/MWh.
- The total paid for power by the LSE is \$170,000, or \$85/MWh. This is also the value of β_L, the shadow price of the load constraint. However, the marginal cost of serving load for the LSE is the sum of this shadow price plus K times the shadow price of the LSE's emissions constraint ($K^*\alpha_L$, 0.55 tons/MWh *\$100/MWh), or \$140/MWh.
- Only generator A makes a profit (of \$140/MWh*500 MW, or \$70,000).

Thus, cleaner generation gets a premium. The premium results from the value it provides to the LSE by making it easier for the LSE to achieve its emissions target; an LSE is willing to pay more for power that is cleaner. As shown in Section A.3, it turns out that the "shadow price" of the LSE's emissions constraint— \$100/ton—*equals* the price of emissions allowances in the source-based example, below.

Now consider a source-based system in the emissions cap is 1100 tons, and consumers own the allowances. It will result in the following equilibrium using the model of Section A.2:

- MW generation y_{Si} from companies i=A,B,C: y_{SA} = 500 MW, y_{SB} = 1000 MW, y_{SC} = 500 MW. These also equal MW purchases by the LSE (x_{SA}, x_{SB}, and x_{SC}, respectively).
- The price for power is \$140/MWh for all producers.
- The price for allowances is \$100/ton. So the total allowances rent is \$110,000. As a result of this price of allowances, the net marginal cost for B's generation is \$140/MWh (=\$80/MWh for fuel + 0.6 ton/MWh*\$100/ton for allowances), which is the same for C (=\$40/MWh for fuel + 1.0 ton/MWh*\$100/ton). Neither B nor C earn any operating profit, as price equals their marginal cost.
- On the other hand, A's marginal cost is \$0, as it has neither fuel costs nor emissions; therefore, it will produce at its 500 MW capacity, and earn \$70,000 in profits (\$140/MWh*500 MW).
- The LSE pays \$280,000 for its power (\$140/MWh*2000 MW). But since consumers own the allowances, they get the allowances rent (\$110,000, e.g., from auctioning the allowances), so the net cost to the LSE is \$170,000 or \$85/MWh.

Thus, the two systems (load-based and source-based/consumer-owned allowances) result in the *same* cost to load. The "Rent to Clean Generation" in both cases accrues to Generator A (the cleanest generator). Generator A earns this rent in the source-based case because it earns the full power price without having to pay for allowances. It earns it in the load-based case because LSEs are willing to pay a premium for its power relative to higher-emissions sources.

Under the California "Standard Practice" for benefit-cost analysis of demand-side programs,[20] "utility avoided costs" quantify the utility's energy cost savings resulting from changes in load. In the models of this Appendix, this equals the per unit reduction in cost to the LSE resulting from a change in load, accounting for all cash flows. In the load-based model of Section A.1, a unit decrease in L lowers the right-hand side of the LSE's emissions constraint by K units (in tons/MWh) and the right-hand side of the LSE's load constraint by 1 unit. This results in a cost savings (change in the LSE's objective function) of $K\alpha_L$ and β_L, respectively, or a total of 0.55 tons/MWh*\$100/MWh + \$85/MWh = \$140/MWh. In the source-based model of Section A.2, a unit decrease in L affects only the right-hand side of the LSE's load constraint (by 1 unit); since its shadow price is β_S = \$140/MWh, the cost-savings to the LSE is the same as in the load-based model. Thus, the "utility avoided cost" is the same under the load-based and source-based models, as we argued in Section 4, *supra.*

[20] "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," October 2001, ftp://ftp.cpuc.ca.gov/puc/energy/electric/energy+efficiency/em+and+v/Std+Practice+Manual.doc

A.5. Analysis of the Gillenwater and Breidenich (2007) (*op. cit.*) Load-Based Proposal

The load-based system Gillenwater and Breidenich (*op. cit.*) propose unbundles emissions and power so that the ISO would not have to track emissions associated with power sources. The proposal has the first seller unbundle the GHG emissions rate from power production; then the seller can sell the GHG rights to load, and power to whomever it wants. The rights are called "Generation Emission Attribute Certificates" (GEAC), have units of energy (MWh), and have the additional attribute of the actual emissions rate of the seller.[21] Thus, the GEACs are a differentiated commodity. Each load-serving entity (LSE) is responsible for buying enough GEACs to meet its load, and the total emissions associated with the GEACs it buys must be no more than the LSE's emissions limit. The idea in the proposal is captured in the following equilibrium model, consisting of a consumer model, a producer model, and market clearing conditions. There are two sets prices that clear the market: p_i (the \$/MWh price of power from producer i) and β (the \$/ton price of CO_2 credits implied by the trading of GEACs).

Consumer Model. The LSE has the following optimization problem. Choose (1) the amount of electricity x to buy and (2) the amount of GEACs z_i to purchase from each producer i in order to maximize net benefits of consumption, subject to regulatory constraints concerning the amount and mix of GEACs that each LSE has to buy.

$$\text{MAX} \ -\Sigma_i\, p_i\, x_i - [\Sigma_i\, \beta\, (K - E_i) z_i]$$

subject to:

$$\Sigma_i\, z_i \ - \Sigma_i\, x_i = 0$$
$$\Sigma_i\, x_i = L$$
$$\Sigma_i\, E_i\, x_i \le K\, L$$
$$x_i \ge 0 \quad \forall i$$

The notation is the same as in the rest of the Appendix, with the addition of a new decision variable z_i, equal to the number of GEACs that the LSE buys from producer i. The next to last constraint says that emission-weighted GEACs can't exceed the target rate times consumption.

The pricing rule for GEACs embodied in the LSE's objective is that a GEAC from producer i would have price $\beta(K - E_i)$ \$/MWh. This is a reasonable interpretation of Gillenwater and Breidenich (*op. cit.*)'s statement that consumers are willing to pay more for cleaner certificates. The rule follows from the reasonable expectation that a consumer should be willing to pay a premium for a certificate that makes it easier to comply with its emissions constraint (*i.e.*, a GEAC whose $E_i < K$), while a consumer would have to be bribed to accept a certificate that makes it more difficult to comply with that constraint (*i.e.*, a GEAC whose $E_i > K$) and, further, the amount of payment should be proportional to the difference between E_i and K. Thus, low emission producers would be paid handsomely for their GEACs, while a coal plant might have to pay LSEs to take the GEACs off its hands.

[21] These are sometimes also called these "Tradable Emission Attribute Certificates."

Other pricing schemes are possible. In particular, make the price of a GEAC from producer i equal to $\beta(H-E_i)$, where H is some arbitrary or default emissions rate; if H is high enough, then all GEACs would have a positive price. However, in a closed power market in which load L is fixed, in equilibrium, this would just serve to lower the price of electricity by $\beta(H-K)$ \$/MWh; this would yield the *same* generation and consumption solution and consumer costs as using H=K. However, in a world in which L is not fixed (due not only to price elasticity, but also due to customer switching among LSEs), the pricing rule $\beta\ (K-E_i)$ is arguably the most sensible one in terms of ease of administration (since LSEs would then not need to be involved in the system; see below).[22] It is shown below that having $K>E^T$ would be equivalent to taxing consumption by a fixed per MWh rate, and that would be a much simpler implementation of this system than asking consumers to track purchases of GEACs.

<u>Producer Model.</u> Each producer i has problem of choosing the amount of generation y_i [MWh] in order to maximize profit.

$$\text{MAX} \quad (p_i - C_j)y_i + \beta\,(K - E_i)y_i$$
$$\text{subject to: } y_i \geq 0$$

If it is a clean producer, it gets paid for credits ($K - E_i > 0$), but if it is dirty, it has to pay consumers to take the credits off its hands ($K - E_i < 0$).

<u>Market Clearing Conditions.</u> There are two market clearing conditions. First, for energy, generation = consumption.

$$x_i = y_i \text{ for all i} \quad \text{(shadow price } p_i\text{)}$$

Second, the amount of GEACs produced by each producer has to equal the amount sold.

$$x_i = z_i \text{ for all i} \quad \text{(shadow price } \beta\,(K - E_i)\text{)}$$

The market equilibrium model consists of combining the first-order conditions of the consumer and producer models with the market clearing conditions.

<u>Example.</u> A consumer has a load of 1 MWh, and two producers are available: A, which has high emissions ($E_A = 1$ ton CO_2/MWh) and B, which has low emissions ($E_B = 0.5$ ton/MWh). The emissions rate target is K = 0.75 tons. The marginal cost of A is \$40/MWh, and B's marginal cost \$70/MWh. The equilibrium is $p_A = p_B =$ \$55/MWh, and $\beta =$ \$60/ton. Producer A has to bribe consumers to take its credits, while producer B gets paid. There is only one electricity price and the ISO does not have to track different "flavors" of electricity.

Interestingly, the consumer pays *nothing* on net for its GEACs; it pays \$60*(0.75-0.5) = \$15 for 0.5 GEACs from producer B, but is paid \$60*(1-0.75) = \$15 for the 0.5 GEACs it accepts from producer A. As is pointed out below, this is no coincidence; each LSE pays \$0 for its

[22] Having a higher default emissions rate ($H > K$) would result in payments, on net, from consumers/LSEs to producers. As shown later in this Appendix, having $H = K$ results in zero net payments.

GEACs. So there is no point to having them participate in the market if another mechanism can be devised to keep track of emission rates; it turns out that one can can be easily devised that only involves producers.

Reduction of the Gillenwater and Breidenich (op. cit.) Load-Based Proposal to a Cap-and-Trade System with Free Allocation of Allowances to Producers. The above model simplifies considerably if it is recognized that the assumed pricing rule will result in consumer's emissions constraint being binding in an optimal solution. Substituting the emissions constraint into the LSE's demand constraint yields

$$\Sigma_i E_i x_i = K \Sigma_i x_i$$

which implies that the objective function term $\beta [\Sigma_i (K - E_i)x_i]$ is identically zero. This means that each LSE pays nothing, on net, for its GEACs. Thus, there is no need to have load participate in this market. The potential complications of having not only to monitor producer emissions but also track producer sales of GEACs to LSEs serves no purpose and can be avoided. This nominally load-based trading system is actually a source-based trading system with the following properties:

1. An elastic cap that is proportional to the emissions rate times total production
2. Free allocation of allowances to producers in proportion to their output

The free allocation means that producers retain the allowances rents under this system.

What if instead of pricing rule $\beta (K - E_i)$ the rule was more generally $\beta (H - E_i)$, with H being a "default emission rate" that differs from the target emissions rate K that the LSE must attain? If the equilibrium price β was unchanged (which might not be the case if demand is elastic), the difference in consumer payment compared to the objective in the above LSE model would be :

$$\beta [\Sigma_i (H - E_i)x_i] - \beta [\Sigma_i (K - E_i)x_i] = \beta (H - K)L$$

That is, this would be equivalent to taxing the consumer by amount β (H–K) per MWh; producers would receive a payment of this amount per MWh generated (assuming no losses). Note that this subsidizes energy production.[23] Therefore, there is no theoretical reason to set up an elaborate load-based accounting system to implement a system with a default emission rate $\neq$ K; one can just use an energy tax and pass its proceeds to generators, or use the energy tax proceeds for other purposes.

The above analysis, strictly speaking, only applies to a closed (no imports) system. Gillenwater and Breidenich (*op. cit.*) propose that it be applied to a system with power imports by

[23] Further, assuming L is fixed (perfectly inelastic), then in equilibrium, the tax payments by consumers would be returned to them in the form of lower power prices, and nothing would be accomplished—the net costs to consumers would be exactly the same. So there would be a reason to do this only if the taxes were used for some purpose other than a subsidy to producers. (In the case of a consumer subsidy paid by producers, power prices would be raised instead.)

allowing producers outside California to voluntarily join the system; there would be an incentive to do so if a producer's emissions E_i were less than the target H. However, this system is subject to the same difficulties concerning contract shuffling as the other systems, as we discuss in Section 2.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the following electronic document: Van Horn Consulting-Comments_CPUC_R.06-04-009-CEC Docket 07-OIIP-01-GHG Regulation-Dec3-2007.pdf on the service list for CPUC Docket No. R.06-04-009 and CEC Docket No. 07-OIIP-01 by serving a copy to each party by electronic mail and/or by mailing a properly addressed copy by first-class mail with postage prepaid.

Executed on December 3, 2007, at Orinda, California.

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