Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of Greenhouse Gas Allowances in the Electricity Sector

California Public Utilities Commission Proceeding # R.06-04-009
California Energy Commission Docket # 07-OIIP-01

JOINT AGENCY STAFF PAPER

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California Public Utilities Commission

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

ADMINISTRATIVE LAW JUDGES' RULING UPDATING PROCEEDING SCHEDULE AND REQUESTING COMMENTS ON EMISSION ALLOWANCE ALLOCATION POLICIES AND OTHER ISSUES

1. Summary

In this ruling, we establish the schedule for further activities that will lead to a joint proposed decision with recommendations to the California Air Resources Board (ARB) on remaining policy issues regarding greenhouse gas (GHG) regulatory strategies for the electricity sector. Parties may file comments on all of these remaining issues in one set of comprehensive comments and reply comments, as directed below.

In this ruling, we request comments on the attached staff paper, which analyzes several potential methods for the allocation of GHG emission allowances, and solicit responses to certain additional questions addressing GHG emission allowance policies. In their comments, parties may propose alternative emission allocation methods. Parties may utilize the GHG Calculator developed by Energy and Environmental Economics, Inc. (E3), as further described below, to help inform their comments and proposals. Another forthcoming ruling

(or rulings) may include additional guidance regarding the scope of parties' comments on other issues, including flexible compliance, treatment of combined heat and power (CHP), and other remaining policy and modeling issues.

2. Proceeding Schedule

We establish the schedule for further activities that will lead to a joint California Public Utilities Commission (Public Utilities Commission) and California Energy Commission (Energy Commission) proposed decision with recommendations to ARB on remaining policy issues for the electricity sector, including allocation of emission allowances, flexible compliance mechanisms, the treatment of CHP facilities, and the electricity sector's potential contribution toward meeting the economy-wide GHG emission reduction goals set by Assembly Bill (AB) 32. Today's ruling provides guidance regarding parties' comments on GHG emission allowance policies. Subsequent ruling(s) will provide additional guidance regarding the scope of comments (which will be due at the same time) addressing modeling results and other policy issues.

As previously noticed, a two-day joint workshop will be held commencing April 21, 2008, at the Public Utilities Commission, which will address the analysis and positions presented in the staff paper and other issues related to GHG emission allocation policies. The workshop will also address preliminary results from E3's Stage 2 modeling efforts, including potential impacts on rates of the allocation proposals in the staff paper. This workshop will be webcast. A preliminary workshop agenda is as follows:

April 21 morning	Overview of changes to E3 model
April 21 afternoon	Presentation and discussion of staff paper on allocation

April 22 morning	Presentation and discussion of preliminary E3 modeling results of allocation options

A more detailed workshop agenda and instructions for accessing the webcast will be posted on the Public Utilities Commission website and e-mailed to the service list in this rulemaking.

An additional workshop on modeling issues will be held on May 6, 2008. At that time, E3 will present final modeling results and will provide parties with training regarding operation of E3's revised GHG Calculator. This workshop should provide parties the information necessary to produce their own modeling scenarios for possible presentation in their comments. The meeting will be webcast and the GHG Calculator in MS-Excel will be viewable over the internet via Web-Ex. Further information about the webcast and the workshop agenda will be e-mailed to the service list in this rulemaking and posted on the Public Utilities Commission website. E3 might make final revisions in response to parties' comments during the workshops, and plans to post the final GHG Calculator shortly thereafter.

The planned schedule addressed in this ruling is summarized below:

Workshop on allowance allocation policies and preliminary E3 model results for Stage 2	April 21-22, 2008
Ruling providing further guidance regarding record development on flexible compliance mechanisms, treatment of CHP facilities, and other issues	April 30, 2008
Workshop on E3 model results and training for operating the E3 GHG Calculator	May 6, 2008
E3 posts revised final model and GHG Calculator	May 10, 2008

Comments due	May 27, 2008
Reply comments due	June 10, 2008

3. GHG Emission Allowance Allocation Methods

On June 22, 2007, a workshop was held at the Energy Commission in this joint Public Utilities Commission and Energy Commission proceeding. While that workshop focused on allocation of GHG emission allowances under a load-based cap for the electricity sector, an October 15, 2007 ruling requested comments on allowance allocation-related issues for a deliverer/first seller approach and also for the natural gas sector, consistent with amendments to the rulemaking adopted in Public Utilities Commission Decision (D.) 07-07-018 and D.07-05-059. A second workshop on emission allocation issues was held at the Energy Commission on November 5, 2007.

In March 2008, the Public Utilities Commission and the Energy Commission adopted a joint decision (Public Utilities Commission D.08-03-018 and Energy Commission Interim Decision CEC-100-2008-002-F, respectively), which recommends that, in implementing AB 32, ARB adopt a mix of direct mandatory/regulatory requirements for the electricity and natural gas sectors and a cap-and-trade system that uses a deliverer approach for the electricity sector. In that decision, the Commissions recommend that some portion of the emission allowances available to the electricity sector should be auctioned. They also recommend that any policy for the distribution of allowances provide that revenues from the sale of allowances be used primarily to benefit consumers in the energy sectors directly.

In the joint decision, the two Commissions conclude further:

> [A]dditional record development is needed to allow us to make more complete recommendations on allowance distribution issues, including the proper mix between auctions and administrative allocations of emission allowances for the electricity sector, the manner in which auction proceeds should be used for the benefit of electricity consumers, and the manner in which any administrative allocations should be made. We will consider various options for the allocation of allowances, including to retail providers and/or deliverers. The concerns of all parties, along with potential solutions, will be considered carefully.[1]

Attached to this ruling is a staff paper which analyzes several potential allowance allocation methodologies. As mentioned above, the two-day workshop on April 21-22, 2008 will address the staff paper and other emission allocation issues, in addition to Stage 2 model results.

Following the workshop, parties are invited to file comments on the staff paper and the two articles attached to the staff paper. Parties may also submit their own proposals for emission allowance allocation methods. Parties may use the evaluation criteria staff uses in its paper, or may propose other criteria, and may use the Stage 2 model to quantify the effects of any proposed allocation method.

In addition to general comments parties may wish to submit, we request that parties address the following specific questions related to emission allocation methods and policies:

1. Please explain in detail your proposal for how GHG emission allowances should be allocated in the electricity sector.

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[1] D.08-03-018, mimeo. at 9.

2. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise concerns under the Dormant Commerce Clause? If so, please explain why that allocation option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.
3. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.
4. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.
5. For reply comments: Do any of the allowance allocation options discussed in other parties' opening comments raise concerns under the Dormant Commerce Clause? If so, please explain why that option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.
6. For reply comments: Do any of the options discussed in other parties' opening comments raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if

and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

7. For reply comments: Do any of the allowance allocation options discussed in other parties' opening comments raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option could be modified to avoid such legal concerns.
8. The staff paper describes an option that would allocate emission allowances directly to retail providers. If you believe that such an approach warrants consideration, please describe in detail how such an approach would work, and its potential advantages or disadvantages relative to other options described in the staff paper. Address any legal issues related to such an approach, as described in Questions 2 – 4 above.
9. Please address the effect that each of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your own or other parties' opening comments, would have on economic efficiency in the economy, and the economic incentives that each option would create for market participants.

In D.08-03-018, the two Commissions concluded that the proceeds from the auction of GHG emission allowances for the electricity sector should be used primarily to benefit electricity consumers in California in some manner. The Commissions identified two methods for returning revenues from allowance auctions: (1) using auction revenues to augment investments in energy efficiency and renewable power, or (2) using revenues to maintain affordable rates. Please answer the following questions regarding the use of auction revenues.

10. Describe in detail the method you prefer for returning auction revenues to benefit electricity consumers in California. In addition to your recommendation, comment on the pros and cons of each method listed above, especially regarding the benefit to electricity consumers, impact on GHG emissions, and impact on consumption of electricity by consumers.

11. If auction revenues are used to augment investments in energy efficiency and renewable power, how much of the auction proceeds should be dedicated to this purpose?
12. If auction revenues are used to maintain affordable rates, should the revenues be used to lower retail providers' overall revenue requirements, returned to electricity consumers directly through a refund, used to provide targeted rate relief to low-income consumers, or used in some other manner? Describe your preferred option in detail. In addition to your recommendation, comment on the pros and cons of each method identified for maintaining reasonable rates.
13. If you prefer a combination of methods for returning auction revenues, describe your preferred combination in detail.

4. Stage 2 Modeling

The purpose of the modeling effort in this proceeding is to produce a tool by which the impact of alternate policy means to achieving emissions reductions within the electricity sector under AB 32 may be quantified. The modeling effort seeks primarily to provide insights about the relative cost-effectiveness of GHG abatement measures available within the electricity sector, as well as the overall cost impacts of achieving GHG emission reductions of varying stringency within the 2020 timeframe. The insights from this modeling effort will inform the two Commissions as they make further recommendations to ARB.

This modeling effort may also assist ARB's macroeconomic modeling of the broader economic impacts of potential GHG emission reduction measures across all sectors in the California economy. The collective insights gained from the electricity sector and macroeconomic modeling will position ARB for making better-informed decisions about assigning sector- and entity-level GHG emission reduction obligations.

The Public Utilities Commission has entered into a contract with E3 as the prime contractor to develop an electricity sector model for evaluating GHG

policies. This project is being overseen by a multi-agency staff team that includes, in addition to Public Utilities Commission staff, representatives of ARB and the Energy Commission.

E3 has divided its analysis into two stages. The first stage was completed in November 2007, and the second stage will be completed by June 2008. In Stage 1, E3 developed several scenarios to model a range of GHG emission reductions for the entire electricity sector and associated cost impacts. By a November 9, 2007 ruling, parties were provided the preliminary results from Stage 1, which E3 then presented at a November 14, 2007 workshop. Parties were permitted to file opening and reply comments during January 2008. In response to those comments and to reflect the deliverer approach adopted in D.08-03-018, E3 has made further modifications to the GHG model and has expanded its functionality to permit modeling of impacts on rates and total program costs of several different allowance allocation methods.

At the two-day workshop commencing on April 21, 2008, E3 will explain modifications done in response to parties' Stage 1 comments, educate parties on the additional functionality of the GHG model, and share preliminary results for Stage 2. An additional workshop on modeling issues will be held on May 6, 2008, during which E3 will present final Stage 2 model results and will provide parties with training regarding operation of the revised GHG Calculator.

Parties may address the E3 modeling effort in their comments and reply comments due on, respectively, May 27, 2008 and June 10, 2008. We may provide additional guidance in an ALJ ruling after the workshops regarding modeling-related information we would like to see in these comments.

5. Filing Requirements

All parties filing comments or reply comments should file them at the Public Utilities Commission's Docket Office and should serve them consistent with Rules 1.9 and 1.10 of the Public Utilities Commission Rules of Practice and Procedure and Resolution ALJ-188. The parties should serve their comments and reply comments on the service list for R.06-04-009 posted at www.cpuc.ca.gov when the filings are due, and should mail a hard copy of the filings to the assigned Commissioner and assigned Administrative Law Judges.

To support the ability of the Public Utilities Commission and the Energy Commission to develop joint recommendations to ARB, we ask that parties submit their comments and reply comments both in R.06-04-009 and to the Energy Commission's docket 07-OIIP-01.

Procedures for submitting the filings to the Energy Commission are included here for the parties' convenience. The Energy Commission encourages comments by e-mail attachments. In the subject line or first paragraph of the comments, include **Docket 07-OIIP-01**. When naming your attached file, please include your name or your organization's name. The attachment should be either in Microsoft Word format or provided as a Portable Document File (PDF). Send your comments to docket@energy.state.ca.us and to project manager Karen Griffin at kgriffin@energy.state.ca.us. In addition to electronic filing, **one paper copy** must also be sent to:

California Energy Commission
Docket Office, MS-4
Re: Docket No. 07-OIIP-01
1516 Ninth Street
Sacramento, CA 95814-5512

IT IS RULED that:

1. As directed in this ruling, parties may file comments no later than May 27, 2008 that address the staff paper on GHG emission allowance allocation methodologies attached to this ruling, and other matters as described in this ruling. Parties may file reply comments no later than June 10, 2008.

2. Parties shall file their comments and reply comments at the Public Utilities Commission's Docket Office and shall serve them consistent with Rules 1.9 and 1.10 and Resolution ALJ-188. The parties shall serve their filings on the service list for R.06-04-009 posted at www.cpuc.ca.gov when the filings are due, and shall mail a hard copy of the comments to the assigned Commissioner and the assigned Administrative Law Judges.

3. As previously noticed, a two-day workshop shall be held on GHG emission allowance allocation issues and modeling issues commencing at 10:00 a.m. on April 21, 2008, at the Public Utilities Commission, 505 Van Ness Avenue, San Francisco, California.

4. Another workshop shall be held on modeling issues and to provide parties with training regarding operation of the revised GHG calculator commencing at 10:00 a.m. on May 6, 2008, at the Public Utilities Commission, 505 Van Ness Avenue, San Francisco, California.

Dated April 16, 2008, at San Francisco, California.

/s/ CHARLOTTE F. TERKEURST	/s/ JONATHAN LAKRITZ
Charlotte F. TerKeurst Administrative Law Judge	Jonathan Lakritz Administrative Law Judge

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated April 16, 2008, at San Francisco, California.

/s/ LILLIAN LI

Lillian Li

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ATTACHMENT

Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of GHG Allowances in the Electricity Sector

R.06-04-009 and D.07-OIIP-01

Principal Authors

Scott Murtishaw, Adam Langton, and Karen Griffin

April 16, 2008

Table of Contents

Executive Summary 1

1. Introduction 5

1.1 Background 5

1.2 Scope of the Staff Paper 7

1.3 Structure of California's Electricity Sector 8

1.4 Structure of this Paper 9

2. Evaluation Criteria for Allocation Options 9

2.1 Consumer Cost: Impacts to Retail Electricity Customers 10

2.2 Equity Among Customers of Retail Providers 11

2.3 Administrative Simplicity 12

2.4 Accommodation of New Resource Entrants 12

3. Overview of Allocation Methods 12

3.1 Emission-Based Allocation 13

3.2 Output-Based Allocation 14

3.3 Auction 14

3.4 Combining Different Methods 15

4. Other Issues Related to Allocation 15

4.1 Allocation and Early Voluntary Reductions 15

4.2 Allocation to Combined Heat and Power Facilities 15

5. Emission-Based Allocation to Deliverers 16

5.1 Mechanics 16

5.2 Analysis of a Pure Emission-Based Approach 17

5.3 Preferred Emission-Based Approach 23

6. Output-Based Allocation 24

6.1 Mechanics 24

6.2 Analysis of Pure Output-Based Allocation 25

6.3 Variations on Output-Based Approaches 28

6.3.1 Benchmark versus Cap 28

6.3.2 Updating Methodology 28

6.3.3 Restriction of Generator/Deliverer Eligibility 28

6.3.4 Differentiated Allocation by Fuel Type 30

6.4 Preferred Output-Based Approach 31

7. Auctioning 32

7.1 Mechanics 32

7.2 Rationale for Retaining Auction Revenue in the Electricity Sector 35

7.3 Analysis of a Pure Auction Method 37

7.4 Variations on Auctioning with Revenue Retention 38

7.5 Preferred Auction Approach 39

8. Summary of the Allocation Methods 40

References 43

Appendix A

Appendix B

Executive Summary

In this proceeding, the California Public Utilities Commission (Public Utilities Commission) and the California Energy Commission (Energy Commission) are making joint recommendations to the Air Resource Board (ARB) on the greenhouse gas (GHG) strategies best suited to the electricity and natural gas sectors. On March 12th and 13th the joint agencies adopted an Interim Opinion on the type and point of regulation and complementary principles and policies for implementing AB 32.

The Interim Opinion also recommends that energy efficiency and renewables should be the foundation of any regulatory approach for the electricity sector and will account for the majority of GHG reductions. The Energy Commission and the Public Utilities Commission base that recommendation on technical and economic analysis of the social and financial benefits of these strategies. Both the Energy Commission and the Public Utilities Commission are aggressively pursuing energy efficiency and renewable energy through building and appliance standards, utility-delivered programs, and research activities.

One current effort in the joint proceeding, which has led to this staff paper, is the development of recommendations on the preferred approach to the allocation or auctioning of allowances, should ARB decide that there will be a cap and trade program in California that includes the electricity sector. As noted in the Interim Opinion, selection of a point of regulation does not predetermine the approach to allowance allocation. Thatdecision adopts some general principles for allowance allocation but does not resolve other allowance allocation issues. . . Public workshops will be held at the Public Utilities Commission in San Francisco on April 21 and 22, 2008 for the purpose of discussing this paper and modeling work. Interested parties will be asked to file comments in May which will assist the Public Utilities Commission and the Energy Commission with developing recommendations to the ARB.

This paper is responsive to the Commissions' direction in the Interim Opinion on GHG regulatory strategies; CEC-100-2008-002-F and Public Utilities Commission Decision (D.) 08-03-018) to develop the record further regarding possible approaches to the allocation of GHG emission allowances. This includes options for administrative allocations and auctions, differing bases for allocating allowances or auction revenue rights for that portion of allowances which are auctioned, and the extent to which the allocation method should change over time. The criteria used for evaluating options are based on the Interim Opinion's direction that allocation policy should ensure that GHG emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers.

Reviewers of this paper should note that the Commissions are undertaking a number of policy and programmatic efforts to address emissions reductions in the electricity and natural gas sectors. The joint Commission proceeding in which this paper is being released represents only one of several dozen venues in which issues related to AB 32 reductions are being addressed. For example, in separate venues, the Commissions are undertaking rulemakings on more aggressive building codes and appliance standards, big/bold energy efficiency programs for investor-owned utilities, statewide coordination of energy efficiency goals and strategic demand-side planning, renewable portfolio standard implementation, the California Solar Initiative, policies for combined heat and power facilities, and a host of other smaller

programs and policies designed to produce GHG emission reductions in these sectors. While the bulk of the current proceeding is focused primarily on the best approach for implementing a market-based mechanism to provide additional GHG reductions beyond mandatory programmatic reductions, this proceeding should not be mistaken for the only or even the main initiative at the two Commissions related to AB 32 goals.

Staff was requested to initiate this portion of the proceeding by developing "staff proposals" or recommendations in order to focus stakeholder comments on the kinds of allocation decisions which will need to be made. This paper actually develops three distinct options to achieve AB 32 GHG emission reductions to serve as straw proposals for review and comment. Staff expects these options and others that will be designed by parties will be the subject of open discussion, modification or additions.

The Legislature listed several criteria that ARB must meet in implementing the State's GHG cap in Part 4 (Section 38562) and Part 5 (Section 38570) of AB 32. While these are important criteria for determining whether or not a cap-and-trade program should be implemented in California, for some of these requirements, we did not find that there was a different impact among the various allocation options examined in this paper. Many important policy criteria have limited impact on which allocation method to choose. The criteria used for evaluating options are based on the Interim Opinion's direction that allocation policy should ensure that GHG emissions reductions are accomplished effectively, at the lowest cost to consumers, and equitably. The four evaluation criteria that staff identified include: consumer cost, equity among customers of retail providers, simplicity, and accommodation of new resource entrants.

The paper analyzes three basic allocation options and variations on those options. For each option, staff discusses how a "pure" approach would work and then suggests a "preferred" modification to use if that overall approach is chosen. The paper will be partnered with modeling results presented by Energy and Environmental Economics (E3) to serve as a straw proposal for focusing parties on the choices which need to be made for recommendation to the ARB's 2008 Scoping Plan. Since staff did not have the completed modeling results in time for preparation of this paper and were not able to thoroughly compare the impact of the options on the California situation, the paper does not recommend an overall preferred approach. Stakeholder comments, workshops, and the material presented here will assist the joint Commissions in comparing alternative options and ultimately recommending a preferred approach.

The three allocation approaches examined are (1) administrative allocation to deliverers based on historical emissions, (2) output-based administrative allocation to deliverers (allowances granted based on electricity delivered), and (3) a large percent auction with distribution of auction revenue rights primarily back to retail providers on behalf of consumers. The three variations suggested by staff as the "preferred" methods are:

1. An initial administrative allocation of no more than 50% of allowances to deliverers on a historical emission basis. The remaining allowances could be distributed entirely by auction, or through a combination of auctioning and output-based allocation. The

share of allowances allocated on an emission basis would decline rapidly in subsequent years.

2. n initial aaaAllocation of 90% of allowances to deliverers on an output basis, with the remainder distributed by auction, transitioning to greater percentages of auctioning. Allowances would only be allocated to deliveries from GHG-emitting resources, and this would be done on a fuel-specific basis.

3. Initially auctioning 75% of allowances, with the remaining allowances allocated administratively. The majority of revenues would be recycled to retail providers on a historical emission basis for uses to implement the goals of AB 32, and the revenue allocation would transition slowly to be based on sales over time.

Table ES-1 summarizes how the allocation methods would perform compared to the evaluation criteria. For each basic method, both the pure and staff-preferred versions are shown. Checks indicate that the method would generally perform well according to that criterion, while an "X" indicates that it would perform relatively poorly.

Table ES-1. Summary of Evaluation Criteria Applied to the Allocation Methods

Allocation Method	Consumer Cost	Transfers among Retail Provider Customers	Admin Simplicity	New Entrants
Pure Emission-Based	✕/✓ [a]	✓	✓	✕
Preferred Emission-Based	✓	✓	✕	✓
Pure Output-Based	✓	✕	✓	✓
Preferred Output-Based	✓	✓	✕	✓
Pure Auction	✕	✕ [b]	✓	✓
Preferred Auction	✓	✓	✕	✓

[a] Emission-based allocation would not produce a transfer to producers for customers of vertically-integrated utilities.

[b] The degree of transfer among retail provider customers would depend on the distribution of the auction revenues.

The pure emission-based allocation of allowances to deliverers would perform well for two of the evaluation criteria. The primary drawback of a pure emission-based method is the risk of large additional profits to deliverers in competitive markets at the expense of most of the electricity customers in California served by investor-owned utilities and electric service providers. An additional concern is that new entrants in electricity markets would be disadvantaged compared to deliverers that had been granted a perpetual allocation of allowances. These two concerns are both addressed in the staff-preferred version in which only half of the allowances would be granted on a historical emission basis, at least 10 percent allocated by auction, and the rest distributed either on an output basis or by additional auctioning.

Both output-based methods would perform well in holding down consumer cost. Any output-based approach with frequent updating would also accommodate new entrants. The pure output-based approach differs significantly from the preferred approach with respect to

transfers of funds among customers of retail providers. While the pure output-based approach would likely result in more transfers from customers of coal-dependent retail providers in the earlysearlyssfirst year of the program, the preferred fuel-specific approach would produce virtually no transfers at the start of the program.

Evaluating the pure auction approach with regard to overall consumer cost and transfers among customers of different retail providers is difficult without specifying what happens to the money raised by the auction. Assuming that auction revenues in the pure auction approach are not used to mitigate consumer costs, auctioning would obviously have significant impacts on rates. Whether a large degree of transfer among customers of different retail providers would also occur depends on how auction revenues would be used. Presumably, under the pure approach, the auction revenues would be spent in ways that benefit all Californians equally. In the recommended auction approach, auction revenues would be distributed to retail providers on behalf of consumers – initially on a historical emissions basis and transitioning to a greater share allocated on a sales basis. This approach would reduce consumer costs and mitigate the concern of transfers among customers of different retail providers, but with some increased administrative complexity. The preferred auction option would also readily accommodate new entrants.

In addition to these staff recommendations outlined above, we have also attached to this paper two important papers on the subject of allowance allocation, which should aid parties' understanding of the allowance allocation issues we face in California.[1]

[1] Appendix A to this paper is a report by the National Commission on Energy Policy, while Appendix B attaches a paper by Resources for the Future developed for the Regional Greenhouse Gas Initiative in the Northeast U.S.

1. Introduction

1.1 Background

The Interim Opinion on Greenhouse Gas (GHG) Regulatory Strategies[2] jointly adopted by the California Energy Commission and the California Public Utilities Commission (Commissions) recommends that the Air Resources Board (ARB) adopt a multi-pronged strategy to reduce GHG emissions in the electricity sector. The approach relies primarily on energy efficiency and renewable energy mandates to meet AB 32 goals. In addition, the Commissions recommend a market-based mechanism to capture additional reductions, to contribute to the ambitious GHG emission reduction targets set forth in AB 32. For the market-based component, the Commissions recommend the establishment of a multi-sector cap-and-trade program, which includes the electricity sector, to deliver additional GHG reductions beyond mandatory measures at the lowest cost to Californians. The Commissions found that a cap-and-trade system "would achieve reductions in the least-cost manner by allowing for flexibility in achieving emissions targets through allowing obligated entities to rely on the least-cost abatement options throughout the economy."[3] Design of such a cap-and-trade program is the subject of further work in this proceeding (R.06-04-009).

Reviewers of this paper should note that the Commissions are undertaking a number of policy and programmatic efforts to address emissions reductions in the electricity and natural gas sectors. The joint Commission proceeding in which this paper is being released represents only one of several dozen venues in which issues related to AB 32 reductions are being addressed. For example, in separate venues, the Commissions are undertaking rulemakings on more aggressive building codes and appliance standards, big/bold energy efficiency programs for investor-owned utilities, statewide coordination of energy efficiency goals and strategic demand-side planning, renewable portfolio standard implementation, the California Solar Initiative, policies for combined heat and power facilities, and a host of other smaller programs and policies designed to produce GHG emission reductions in these sectors. While the bulk of the current proceeding is focused primarily on the best approach for implementing a market-based mechanism to provide additional GHG reductions beyond mandatory programmatic reductions, this proceeding should not be mistaken for the only, or even the main, initiative at the two Commissions related to AB 32 goals.

The two Commissions are working with ARB to ensure that all of the work associated with clean energy initiatives is reflected in the draft scoping plan produced by ARB. In this particular proceeding, the interim decision referenced above recommended both programmatic approaches and the development of a cap-and-trade program for the electricity sector. The remainder of this proceeding will develop recommendations necessary to implement a cap-and-trade system for electricity, should ARB decide that one is warranted. We recognize that in order to include a cap-and-trade system in its scoping plan, ARB is required by AB 32 to perform certain analyses. We do not further address those requirements

[2] Energy Commission Interim Decision CEC-100-2008-002-F (http://www.energy.ca.gov/2008publications/CEC-100-2008-002/CEC-100-2008-002-F.PDF) adopted March 12, 2008 and Public Utilities Commission Decision D.08-03-018 (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/80150.htm) adopted March 13, 2008.

[3] D.08-03-018, p. 5.

in this paper, but remain confident that ARB will fulfill those obligations. Instead, we focus our attention on developing further recommendations to deliver to ARB in the event that they determine that a cap-and-trade system should be designed that includes the electricity sector.

One of the main issues associated with cap-and-trade design is the manner in which responsibility is assigned to individual entities for participation in the program. These rights and responsibilities are called "allowances" and represent the right of a regulated entity to emit a certain quantity of pollution per allowance, usually one metric ton of CO_2 equivalent (CO_2e) for each allowance. At the conclusion of a compliance period, the regulated entities, which the Commissions have recommended be the deliverers of electricity to California's grid, must surrender the number of allowances that match the quantity of pollution emitted. Any shortfall would subject the regulated entity to fines and/or other enforcement actions. Because these allowances can be traded among regulated entities, these allowances have value – a value determined by the supply of allowances and the demand to emit GHGs.

A key aspect of designing cap-and-trade systems is determining a method for distributing GHG allowances. There are two main options for distribution of these allowances. The state may either allocate allowances administratively or it may choose to auction all or a portion of the allowances.

The Interim Opinion recommends to ARB that "some portion of the GHG emission allowances available to the electricity sector be auctioned."[4] This recommendation was predicated on the use of the majority of proceeds to benefit electricity consumers through investments in programs like energy efficiency and renewable energy or through direct customer bill relief.

In the Interim Opinion, the Commissions determined that the record was insufficient at the time to decide the appropriate percentage of allowances to auction, the manner in which to distribute auction proceeds, whether the share of allowances auctioned should change over time, and the method to be used for administratively allocating whatever allowances are not auctioned.[5] However, the Interim Opinion did provide some broad guidance about the direction of future recommendations on allocation.

> "In addressing allocation issues, we keep in mind that some deliverers of electricity to the California grid are also retail providers of electricity for consumers. We also recognize that allocation policy will have an impact on consumer costs. Our intent in developing additional allocation policy recommendations is to ensure that GHG emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers. While we may wish to reward early actions to reduce GHG emissions in advance of 2012 when the AB 32 compliance period begins, it is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32."[6]

[4] D.08-03-018, p. 8.
[5] D.08-08-018, p. 9 and p. 131.
[6] D.08-08-018, p. 7.

Allocation is fundamentally a question of allocating the value that allowances represent. The State can conduct this allocation of allowance value either by administratively allocating the actual allowances themselves or by first auctioning allowances and then allocating the resulting revenues. Theoretically, any method of allocating actual allowances to various entities may be replicated by allocating auction revenues on an identical basis (CBO 2001).

For example, allowances could be allocated to GHG emitting facilities on a historical emissions basis, as is the case for approximately 97% of the SO_x allowances in the Acid Rain program. Similarly, allowances could be auctioned with the revenues returned to GHG emitting facilities in proportion to historical emissions resulting in the same distribution of allowance value (which is the case for the other 3% of SO_x allowances). The allowance value (i.e., the auction revenues) may be distributed according to defined auction revenue rights (ARRs).

A nearly infinite number of approaches to allowance allocation are possible. As many parties correctly noted earlier in this proceeding and as discussed in the Market Advisory Committee report, the question of the point of regulation in the electricity sector can be separated from the question of how allowances are granted and to whom. The Interim Opinion resolves the question of the point of regulation by determining that deliverers of electricity to the California grid should have responsibility for the emissions associated with that delivered power. DDDdeliverers are the entities who will ultimately be required to surrender allowances at the end of a compliance period in the cap-and-trade system to show that they have covered their emissions with sufficient allowances. If they do not do so, they could be subjected to penalties and/or fines.

Therefore, we assume that the deliverers are the entities who will ultimately require access to allowances. However, it does not necessarily follow that allowances must be granted to the deliverers if they are administratively allocated. It is possible that allowances (or their value) could be granted to regulated or publicly-owned retail providers of electricity on behalf of their consumers. Throughout this paper, we bear in mind that ultimately consumers will be paying the cost of these allowances that will eventually become embedded in their cost of electricity. The manner in which allowances are allocated can have profound effects on the prices consumers will ultimately pay for their electricity. Thus, our ultimate goal is to design allowance allocation policy to ensure that the GHG reductions in the electricity sector are delivered at the lowest possible cost to consumers under this structure.

1.2 Scope of the Staff Paper

For purposes of this paper, we assume that the electricity sector participation in a cap-and-trade system will occur in the context of a multi-sector program statewide in California. It is possible that in that context, ARB could decide to hold a multi-sector auction in which all participating sectors must purchase their allowances. In that situation, there would not be a need for as detailed a recommendation as we contemplate here, though the state would still need to determine how revenues from the auction would be allocated to certain sectors or GHG-reducing activities within the state.

However, if some administrative allocation to sectors is contemplated, which we assume here, allocation of allowances (or allowance value) in a multi-sector program will likely occur in two stages. First, the State will need to determine the number of allowances to allocate to each sector. Then a method will need to be selected for allocating among affected entities within each sector.[7] This staff proposal focuses exclusively on the question of how to allocate a given amount of allowances to entities within the electric sector. It does not make a recommendation on the issue of how many allowances should be allocated to the electric sector, assuming that ARB does implement a multi-sector cap-and-trade system. However, some values for allocation to the electric sector are used for illustrative purposes at various points in this paper. In addition, the Commissions expect to provide guidance to ARB on the question of electric sector responsibility for reductions separately from the allocation issues, informed by modeling work being conducted by Energy and Environmental Economics (E3). Parties will have an opportunity to comment on this information and analysis separately.

This paper is part of a suite of program design issues to be addressed in this part of the proceeding. Modeling by E3 will also analyze revenue requirements of the seven retail provider groupings in their model that may result from various scenarios of allowance prices, allowance allocation, and flexible compliance mechanisms. The record will also be developed separately for flexible compliance mechanisms (such as offsets, banking and borrowing, and other price stabilization measures) and other design and implementation questions.

Since the aim of this paper is focused on the basis for allocating allowance value among electricity sector entities, staff has not delved into the finer points of auction design. While it is critically important to design auctions in a way to prevent collusion and abuse of market power, we expect that auction design will be undertaken later under ARB guidance, if ARB decides to explore auctions as an allocation mechanism in its scoping plan. We also refer parties who are interested in this topic to an auction design report that was commissioned for the Regional Greenhouse Gas Initiative (Holt et al. 2007).

Given the complexity of this topic and the ramifications to retail providers and their customers of distributing potentially billions of dollars of allowance value each year, staff analysis in this paper only provides options to the Commissions at an intermediate level of detail. Recommendations in this staff paper are provided in suggested ranges of percentages to auction or freely allocate rather than firm commitments to specific percentages or timetables. Staff expects that additional refinement of the recommended allocation methods will occur between the decision the Commissions will issue later this year and the release of ARB's implementation plan, which must be completed by January 1, 2011.

1.3 Structure of California's Electricity Sector

Evaluating the implications of various allocation methods is complicated by the mixed market structure that exists in California. Most customers in California are served by retail providers that largely rely on independent power producers and marketers in competitive wholesale markets, while others are served by fully-resourced, vertically-integrated utilities. Customers

[7] This is not true in cap-and-trade systems in which there is no administrative allocation of allowance value – that is, where all allowances are auctioned and the revenue is not redistributed in a sectorally differentiated way.

that depend on wholesale markets consist mostly of those served by investor-owned utilities (IOUs) but also include customers of electric service providers (ESPs) and many of the publicly-owned utilities (POUs). Some allocation methods are likely to have different impacts on the customers of fully-resourced utilities compared to customers that are market dependent. In particular, some allocation methods may create the potential for substantial windfall profits for independent generators and/or deliverers, an outcome that customers of fully-resourced utilities may be shielded from by rate regulation and/or their public ownership structures.

Currently, some retail providers have a high carbon-emitting resource base, while others are relatively low-carbon. Some areas of the state are growing quickly, while others are growing slowly or not at all. These differences mean that retail service providers who choose to reduce their carbon footprint will have different trajectories for doing so and will have more or fewer requirements to change over their infrastructure by 2020 and beyond. By choosing deliverers of electricity as the point of regulation for the electricity sector, we have made the stake of retail providers overall in California more indirect than would have been the case under a load-based system. Deliverers (representing electricity supply, not demand) will be the entities responsible for covering their emissions, though of course a number of deliverers (particularly publicly-owned utilities) are also retail providers.

In addition, there is wide diversity in the types of resources upon which retail providers in California rely for delivering power to consumers. The range of renewable resources in the portfolios of various retail providers can range between close to zero and 60%, depending on the utility.

In assessing the different approaches of allocating allowances in the electricity sector, we have attempted to take these different market structures and resource portfolios into account to devise approaches that minimize redistributive outcomes while treating deliverers consistently.

1.4 Structure of this Paper

The criteria used to evaluate among allocation methods are explained in Section 2. A brief overview of the three main methods of allocating environmental allowances is given in Section 3, followed by a discussion in Section 4 of combined heat and power (CHP) and compensation for early voluntary action, two topics related to allowance allocation that are not analyzed in depth in this paper. Sections 5, 6, and 7 delve into more detailed analysis of each of the three main allocation methods. Each of these sections explains the "mechanics" of how a particular method would be implemented, provides an assessment of the likely outcome of implementing a "pure" version of that approach, and presents the staff recommendation for a potential program design using that approach. Section 8 summarizes the staff recommendations.

2. Evaluation Criteria for Allocation Options

Staff developed evaluation criteria to help guide the analysis of the allocation options. We have limited the set of criteria to those that are most germane to allocation and excluded

criteria for which all options are likely to perform equally. Other criteria have been included in the Market Advisory Committee (MAC) report and the Commissions' previous decisions and rulings in this proceeding. Some of these criteria pertain to other elements of system design or the interaction between a GHG cap-and-trade program and regulation of local air pollutants.

The legislature listed several criteria that ARB must meet in implementing the State's GHG cap in Part 4 (Section 38562) and Part 5 (Section 38570) of AB 32. For some of the requirements, we did not find that there would be a different impact among the various allocation options examined. For example, compliance with the requirement that future regulations (Section 38562(b)(4) and Section 38570(b)(2)) must prevent any increase in the emissions of toxic air contaminants or criteria air pollutants does not depend on the allocation approach. That is a function of the total number of allowances issued and the continued enforcement of other federal, State, and local air pollution regulations. Additionally, Section 38570(b)(1) requires ARB to consider "localized emission impacts in communities already adversely impacted by air pollution." This requirement also does not help to differentiate one allocation method from another because, once issued, an allowance may be used by any regulated electricity deliverer or other source in any location. As stated in the Interim Decision, the Commissions expect that any program to regulate GHGs must also be consistent with other federal, State, and local environmental regulations.

Similarly, the requirement that the design achieves the maximum feasible, cost-effective reductions at lowest cost to California is one reason for recommending a market-based mechanism, but allocation is primarily an issue of distribution of the resulting costs and benefits among different sectors of society, not the total cost to society. We recognize that AB 32 requires achieving real GHG reductions, which is the focus of all of our efforts. However, that requirement does not help us distinguish among allocation options; it is chiefly a function of how the declining cap is set for the cap-and-trade system as a whole.

For other AB 32 criteria, we did find that the allocation methods may have different impacts. Those criteria are incorporated into the list below that staff determined best differentiate the allocation options.

2.1 Consumer Cost: Impacts to Retail Electricity Customers

Consumer costs refer to the expenditures that end users of electricity will incur as a result of the cap-and-trade program. As noted above, the Commissions have determined that deliverers of electricity should face the compliance obligation. However, the cost of that compliance will ultimately be passed on to consumers on their electricity bills. Consumer cost consists of two elements: the true social cost of mitigation (reductions in GHG emissions) that is borne by consumers and transfers of wealth from consumers to producers (or deliverers). Some methods of allowance allocation are likely to yield large transfers of wealth from consumers of electricity to producers or deliverers. This occurs when producers are largely compensated for GHG costs through increased prices while also receiving allowances freely (CBO 2001; Burtraw and Palmer 2007; NCEP 2007; MAC 2007). This criterion is related to Section 38652(b)(1) and Section 38652(b)(2) of AB 32.

Note that a trade-off exists between the total social cost of reducing GHGs and reducing consumer cost in ways that blunt the price signal. Allowance value can be distributed in various ways, some that reduce the economic burden on consumers by directly mitigating the price impact and others that provide additional income to consumers without affecting prices. A price-mitigating approach entails using allowances to encourage output (described in more detail in Section 6) or to lower retail electricity rates. Examples of income-enhancing approaches are the use of auction revenues to reduce personal income tax rates or to provide lump-sum payments to households. Price-mitigating approaches induce greater consumption than income enhancing refunds that leave consumers exposed to the full embedded GHG cost of the energy they consume (Burtraw and Palmer 2007). To the extent that consumers are shielded from the costs, GHG targets must be reached either by achieving greater reductions in other sectors or by reducing the GHG intensity of electricity to a greater degree than would otherwise be necessary.

2.2 Equity Among Customers of Retail Providers

As the Commissions state in the Interim Opinion, "[I]t is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32."[8] Thus, under this criterion, any recommended allocation method should not result in large redistributions of funds from one set of retail provider consumers to another as a result of actions taken prior to AB 32. While retail providers who are also deliverers should be encouraged to achieve positive environmental performance, the allocation method should not result in redistribution of wealth among the customers of retail providers for reasons unrelated to mitigating climate change, such as access to or dependence on resources determined largely by geographic or historical circumstances. This criterion is consistent with Section 38562(b)(1).

Again, we emphasize that the compliance burden will be on deliverers of electricity. In some cases, deliverers are also retail providers, to varying degrees. To determine the impacts of various allocation options on consumers of retail providers requires a complex analysis of differing circumstances related to the supply of electricity.

It is also important to point out the difference between allocation methods that redistribute wealth due to retail providers' differential starting points and the flows of allowance value that occur as a benefit of trade. Under any allocation option, some sets of consumers of some retail providers will face higher costs than others purely because their costs to reduce greenhouse gas emissions will be higher. Much of the value of a cap-and-trade system can be found in equalizing those costs of reductions across the entire sector by allowing trading to occur. If the cost of reductions is less onerous in a particular geographic area, deliverers with more expensive costs of mitigation should instead be willing to buy allowances from those who have lower costs of compliance.

[8] D.08-03-018, p. 8.

2.3 Administrative Simplicity

Staff recommends that policymakers choose an allocation method that is reasonably easy to understand and administer. This is desirable because stakeholders need to be able to reasonably predict the consequences of the program. This criterion is drawn from Section 38562(b)(7).

2.4 Accommodation of New Resource Entrants

Under this criterion, allocation methods should not inhibit new deliverers of electricity from entering the market. New market entrants may be able to provide cost-effective emission reductions by bringing new, low-GHG power online. This is consistent with Section 38562(b)(1), Section 38562(b)(5), and Section 38562(b)(6).

3. Overview of Allocation Methods

Allowances may be allocated using any number of methods. The two basic options for allocating allowances to regulated entities are administrative distribution and auction. Administrative distribution usually entails the free allocation of allowances to regulated sources, although the allowances could also be made available at a fixed price rather than distributed for free. Two methods of administrative allocation, emission-based and output-based, are commonly described in the cap-and-trade literature, but many other variations are possible.

Previously in this proceeding, the Commissions received comments from parties that proposed certain allocation methods that have not been employed to our knowledge and that have been subjected to much less analysis in the economic literature. These proposals are not discussed in this paper. They may have merit, but we have fewer tools and historical examples to assess them. The proposals include the "economic harm" method suggested by Southern California Edison,[9] an allocation of rights to purchase allowances at a fixed price suggested by the Green Power Institute, and an allocation of allowances to all Californians on an equal per capita basis submitted by the Climate Protection Campaign.[10] While parties to this proceeding are free to provide more information and analysis of these options, we do not pursue them further in this paper.

[9] Staff is aware of only one study that has modeled this method of allocation. Burtraw and Palmer (2007) modeled the effect of auctioning and emission-based allocation on the market value of U.S. electricity generators at the facility, firm, and industry level. The findings indicate that at the low allowance prices modeled, full auctioning would cause a loss in market value of $50 billion for certain generation facilities; however, another group of facilities would gain $41 billion of market value. At the generation firm level, losing firms suffer a loss of market value of $14 billion, but other firms gain market value of $5 billion. At the industry level, the total loss is $9 billion, or roughly 6% of the $141 billion total net present value of the allowances issued. Compensation at the facility level would, in this example, overcompensate the industry by $41 billion, while compensation at the firm level would overcompensate the industry by $5 billion. This report demonstrates the complexity of determining what might constitute "economic harm." Implementing this method in practice would seem to require that loss in market value be accurately predicted at the firm level if allowances were to be allocated according to a pre-determined formula or schedule.

[10] These comments were submitted in response to the ALJ Ruling of October 15, 2007.

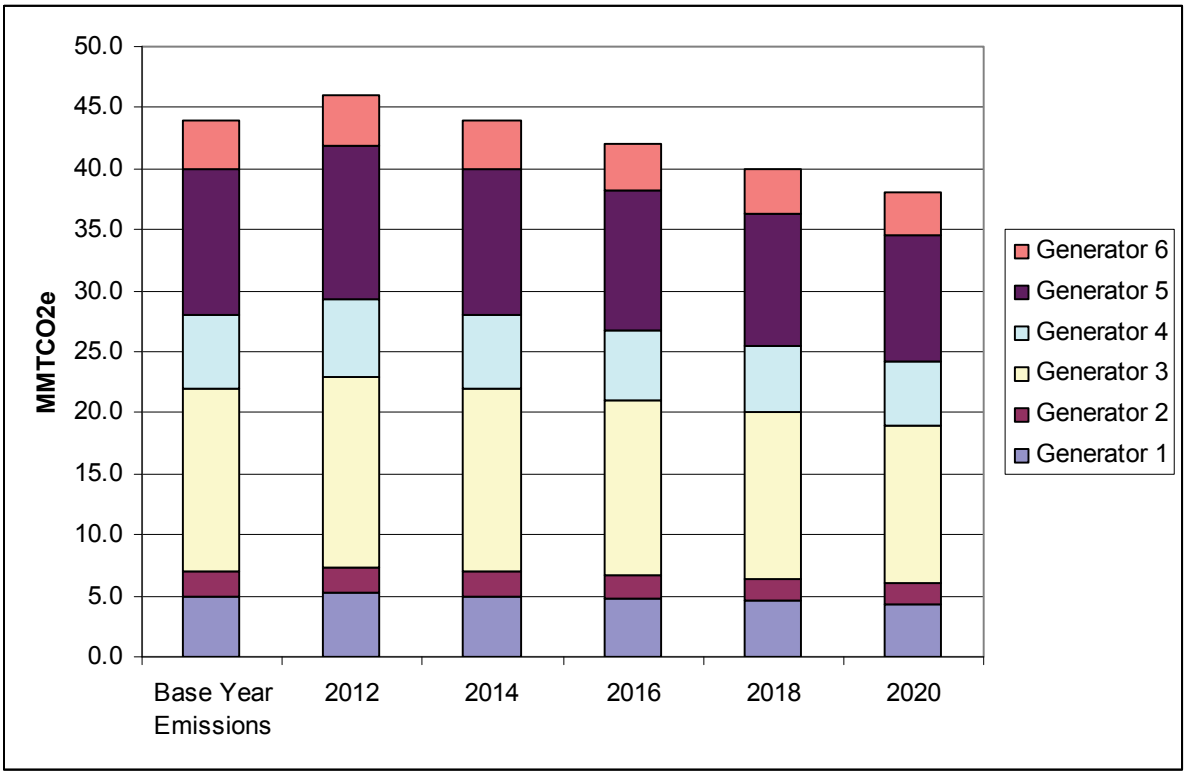
Three basic allocation method options will be covered in this paper: emission-based allocation, output-based allocation, and auction.

3.1 Emission-Based Allocation

Under some existing cap-and-trade programs for air pollutants, allowances have been allocated to sources on an emission basis, generally in proportion to the emissions produced during a baseline period.[11] For example, a facility that emitted 5% of the emissions during the baseline period would receive 5% of the allowances distributed during a given compliance period. Usually, the baseline period is static. In other words, once the baseline period proportions have been established, they are never updated. This is typically to avoid any potential incentives for sources to increase their emissions in order to receive a higher allocation in an updated period.

The EPA's Acid Rain program and Phase I of European Union Emission Trading Scheme (EU ETS) both allocated most allowances to sources on the basis of a historical baseline period. As the total number of allowances declines over time, each entity receives fewer allowances, in proportion to the overall decline in the cap. In the Acid Rain program, this is done in equal proportion across all facilities, as shown in Figure 1. Other methods are possible, such as steeper rates of decline for higher-emitting facilities.

Figure 1. Emission-Based Allocation of Allowances with Equal Rate of Decline



[11] This method is often referred to as "grandfathering."

In the Acid Rain program, the allowances are allocated according to baseline period emissions in perpetuity, even if a facility shuts down. However, some EU ETS member countries have different rules that require the allowances issued to a closed facility either to be transferred to a new facility owned by the same firm or be surrendered back to the government.

3.2 Output-Based Allocation

Output-based allocation methods give allowances to regulated entities according to their output. In the electricity sector, this would entail giving allowances to deliverers for every megawatt-hour (MWh) delivered to the California grid. Several variations of an output-based approach are possible. The eligible pool of delivered electricity can be restricted by fuel or technology types, which increases the rate at which the remaining deliverers receive allowances. Such a method tends to incentivize those entities that produce their outputs at lower emission rates and disincentivize those whose production is more emission intensive. This is because although allowances would be granted based on MWh delivered, deliverers would still need to surrender enough allowances for compliance purposes to cover all of the emissions associated with their electricity deliveries. Thus, deliverers with cleaner than average portfolios will have excess allowances, while those with more carbon-intensive portfolios will need to buy allowances to cover their emissions.

Output-based approaches are usually discussed in combination with updating, but they could be used without updating. "Updating" refers to a variation on administrative allocation methods in which changes in regulated entities' production or emissions have some impact on their future allocations. In other words, the baseline upon which the allocations are based will be updated periodically to reflect changing circumstances. Updating is generally considered with output-based allocation methods because it does not create a disincentive for emissions reductions the way it would if updating were used with an emission-based method. In this staff paper, we assume that output-based allocations would also be regularly updated.

3.3 Auction

Under this method, some quantity of allowances is auctioned by the State on a periodic basis. A wide variety of auction designs are possible, with different options for the frequency of the auctions, limitations on participation in the auction, and the manner in which bids are made and prices set in the auction. For example, auctions could occur on an annual, quarterly, or monthly basis. Auction participation could be completely open, limited exclusively to the entities regulated under the cap-and-trade program, or regulated entities could have the option to bid on an initial block of allowances with the remaining portion auctioned in open rounds.

A crucial distinction between auctioning and administrative allocation of allowances is that while auctioning is a method of distributing allowances, it is not a method of distributing allowance value. Because auctioning generates revenue, further decisions must be made about the disposition of the funds raised through the auction. One option for distribution of these funds, as discussed in this paper, is the allocation of auction revenue rights (ARRs). These can be assigned on the same bases possible for allocation of allowances themselves (i.e., historical emissions, output basis, sales basis, etc.). The ARRs can also be assigned to entities other than those with the compliance obligation. For example, in this paper we consider the distribution

of ARRs to retail providers on behalf of their consumers. We also discuss the option for allocating allowances directly to retail providers, but requiring that they sell those allowances at auction to generate revenues for consumer purposes.

In all discussion of auctioning in this paper, we assume that the auction itself, if one comes to pass, would be conducted by ARB and/or its agent.

3.4 Combining Different Methods

These three methods may be used in various combinations by setting aside one portion of the pool of allowances to be allocated by one method with the remaining portion allocated using a different method. For example, 50% of the allowances could be allocated on an emission basis and 50% allocated on an output basis.

If a combination of methods is used, the shares of the allowance pool allocated according to each method can change over time. For example, equity considerations might argue against an emission-based allocation in perpetuity. Facilities that have shut down no longer have any need for allowances, and it is difficult to justify a permanent source of income to the shareholders of companies that operated these facilities during the baseline period.

4. Other Issues Related to Allocation

4.1 Allocation and Early Voluntary Reductions

This staff paper does not address the question of early voluntary reductions per se. ARB is continuing to develop guidelines for recognizing early reductions, and subsequent workshops or rulings in this proceeding may seek input from parties on this topic. However, it is worth noting that two of the allocation methods described above indirectly reward early reductions – auctioning, by reducing the number of allowances that must be purchased, and output-based, by reducing emissions relative to the benchmark rate (MAC 2007, p. 61). While emission-based methods may not compensate entities that undertook GHG-reducing actions prior to the time period used to establish the baseline, they reward GHG-reducing actions performed after the baseline period but prior to the compliance period. If an emission-based allocation method is pursued, it may necessitate greater attention to the development of measures that directly reward early action.

4.2 Allocation to Combined Heat and Power Facilities

In the Interim Opinion, the Commissions state,

> "[W]e plan to consider further the treatment of combined heat and power (CHP) facilities under this policy framework. We want to avoid unintended negative consequences for CHP, which may be a valuable source of additional GHG emissions reductions in California. Therefore, we intend to consider further the treatment of emissions from CHP facilities in the next portion of this proceeding…"[12]

[12] D.08-03-018, p. 10

This paper does not address the issue of how best to incorporate CHP facilities into a multi-sector cap-and-trade program. A forthcoming staff paper will consider CHP issues in more depth. That staff paper will take into account the three different staff recommended allocation methods proposed in this paper. Since it is primarily the allocation of allowance value that may inadvertently harm CHP facilities in a cap-and-trade system relative to other producers and consumers of electricity, we provide a few key thoughts on the interaction between CHP and allocation methods.

Regardless of the sectoral classification of CHP recommended in a cap-and-trade program design, allowances should be allocated in a manner that avoids inadvertently deterring either the continued operation of or new investment in CHP solely because of the allocation method chosen. Our concern here is to design an allocation method that avoids inadvertently discouraging CHP. In this paper, we take no position now on whether CHP systems should be deliberately incentivized by the allocation method or in any other manner.

Depending on the method of allocation, the cost impact of the cap-and-trade system can be cushioned at either the production or consumption side of an electricity transaction. Since sites with CHP facilities are both producers and consumers of electricity, staff recommends that the allocation option chosen should maintain a level playing field for both activities.[13] To do this, all generation by CHP facilities, whether used on-site or delivered to the grid, should at a minimum receive allowances in a manner consistent with the rules applied to electricity that is delivered to the grid by other deliverers. Additionally, any funds made available for rate relief for electricity consumed from the grid should be available at the same rate for on-site consumption from CHP facilities. Differential treatment of either consumption or production could have the effect of discouraging (or incentivizing) CHP. Recommendations regarding an overall approach to treatment of CHP under an electricity sector cap-and-trade system will be explored in further depth later in this proceeding.

5. Emission-Based Allocation to Deliverers

5.1 Mechanics

An emission-based allocation distributes emission allowances freely to deliverers or other emitting entities in proportion to the emissions produced during a baseline period. The EU ETS, the Regional Clean Air Incentives Market (RECLAIM) program in Southern California and the EPA's Acid Rain program all allocate most allowances based on historical emissions. In RECLAIM, regulators issued allowances to emitting entities in proportion to their highest annual emissions level between 1989 and 1991, less reductions from regulatory requirements established after 1992. In the EU, each Member State received its own emission allocation based on emission levels from 1998 through 2002. In the EPA's Acid Rain program, emissions were set based on an estimated emissions rate multiplied by average fuel consumption between 1985 and 1987. Regulators sought a baseline year that was not impacted by abnormal production conditions. In each of these systems, allocations are proportionally reduced at pre-determined intervals as the emissions cap decreases

[13] We do not address allocation for useful thermal output in this paper.

We do not have adequate information to make a specific recommendation in this paper regarding the appropriate baseline period if emission-based allocations are employed in the electricity sector. Since the electricity sector is subject to large swings in emission levels due to hydro generation and weather variability, staff recommends that the baseline period should, to the extent possible, be based on one or more years marked by average levels of hydro generation and average cooling degree-days.[14] Establishing an averaged multi-year baseline may help accomplish this goal, as well as reducing the impact of annual variations in deliveries from individual deliverers.

One challenge to distributing allowances using historical emission-based allocation involves distributing emission allowances to deliverers of unspecified power. After establishing a baseline period, the State would need to determine the emissions associated with unspecified power in order to allocate the appropriate allowances to the responsible deliverers.

5.2 Analysis of a Pure Emission-Based Approach

A pure emission based approach would consist of identifying the deliverers of electricity to the California grid during the baseline period and determining the emissions associated with those deliveries. All of the allowances for each vintage would be allocated to the entities identified as delivering electricity during the baseline period in proportion to their emissions during the baseline period. The allocations would decline at the same rate for each identified deliverer and would continue in perpetuity.

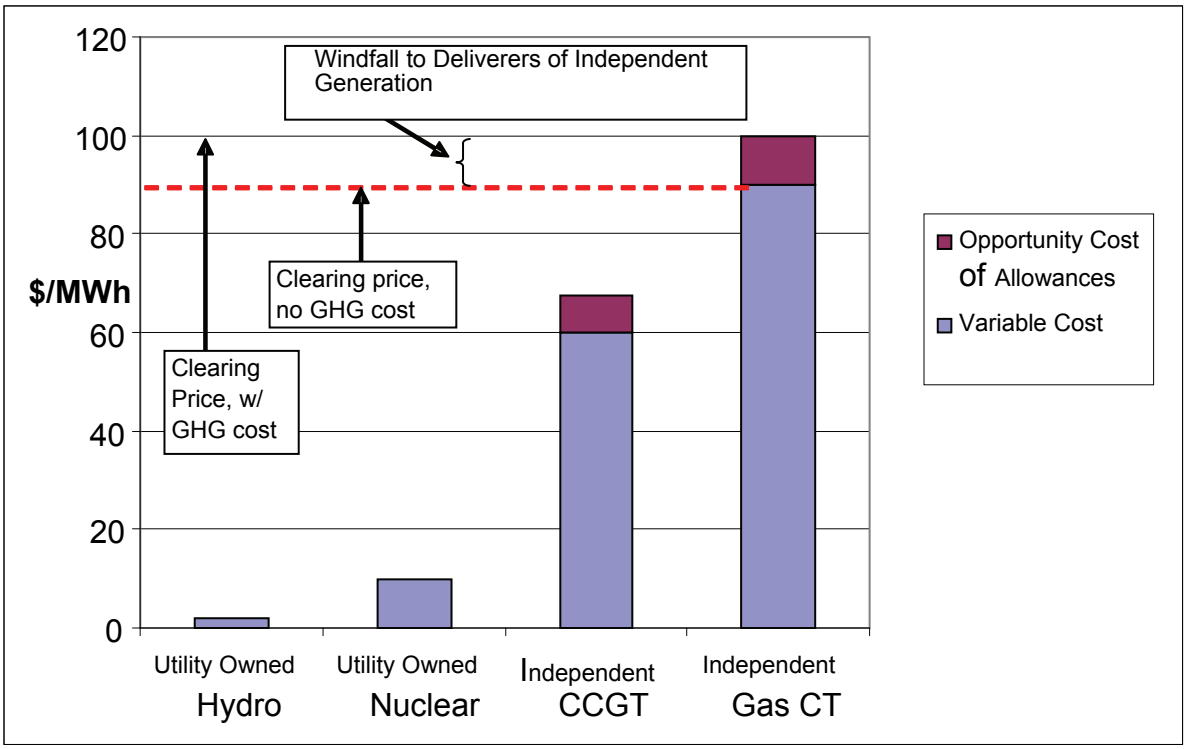
The primary concern about implementing this approach is the likely impact it would have on consumer costs. Regardless of the allocation procedure used, allowances have monetary value. This value is determined by supply and demand. By restricting carbon emissions, a GHG cap-and-trade program would create demand for allowances, since deliverers would no longer be able to emit GHGs without cost. Economic analysis of emission-based allocation predicts that the value of allowances will be factored into electricity costs despite the allowances being allocated freely (Burtraw et al 2001, NCEP 2007, Cramton and Kerr 2002).

To understand why the allowance value would be included in electricity prices, imagine a deliverer with a power plant that emits 0.5 metric ton CO_2e for every MWh generated and allowances are trading at $40. In this case, each MWh has an allowance opportunity cost of $20. Assume tttThe deliverer bids into the spot market at its marginal cost of $70 per MWh without including the value, or opportunity cost, of the allowance. In this example, assume that the market clears at $80 per MWh. The deliverer makes $10 per MWh by delivering power into this market. However, if the deliverer had not run its power plant, it would have been able to sell its allowances at the rate of $20 per MWh. By not factoring the opportunity cost into its bid, the deliverer would be worse off by $10 for every MWh it delivers than it would have been had it not run its power plant at all. In order to be indifferent between delivering power into the market or not, the deliverer would need to increase its bids to $90 per MWh.

[14] The baseline period should not include future years closer to the start of the cap because that would create a perverse incentive to emit more GHGs during the baseline years.

Deliverers serving market-dependent retail providers are very likely to pass through most of the opportunity cost of allowances in their bid prices, which in turn would be reflected eventually on consumer bills. This phenomenon would not be as likely to affect fully-resourced retail providers (those owning sufficient generation to meet their own loads), assuming that they would be restricted by their governing boards or regulators from passing on the opportunity cost of the allowances to their customers (Burtraw and Palmer 2007). Figure 2 depicts how the opportunity cost of allowances would result in substantial additional profits for deliverers of independent generation.[15] The additional profits would not accrue for utility-owned generation if the bodies that oversee those regulated or publicly-owned deliverers do not allow the opportunity cost of freely allocated allowances to be passed through to customers.[16]

Figure 2. Illustration of Potential for Windfall Profits that Accrue to Deliverers of Independent Generation



In order to roughly estimate the annual potential for windfall profits, staff examined the 2005 California Climate Action Registry Power/Utility Protocol reports for the four largest market-

[15] Additional profits earned by a firm or industry that are unrelated to additional work or output are generally referred to as "windfall" profits in economics.

[16] This would not apply to surplus generation belonging to one utility that is bidding into a competitive market to serve other loads.

dependent retail providers in California.[17] These reports provide the total quantity of wholesale power purchased from independent generators, other utilities, and marketers, in most cases disaggregated by resource type. Table 1 shows the result of this analysis. The four retail providers listed purchased over 112 million MWhs of electricity in 2005. For this calculation, it is assumed that the marginal source of power is usually a deliverer providing power from a gas-fired generator. At an assumed allowance price of $20 per metric ton, the opportunity cost of a gas-fired generator with an emission rate of 0.4 metric ton per MWh is $8 for each MWh generated.[18] If the opportunity cost were fully passed through, independent deliverers would stand to benefit from nearly $900 million a year in windfall profits.

Table 1. Potential Losses to Customers of Four California Retail Providers due to Windfall Profits, $20 per Metric Ton Allowance Price

Retail Provider	Million MWh Purchased in 2005	Potential Windfall Profit Paid to Deliverers, Million $ [a]
Pacific Gas and Electric	47.3	$378
Sacramento MUD	8.0	$64
San Diego Gas & Electric	12.9	$103
Southern California Edison	44.0	$352
Total	112.2	$897

[a] Assumes wholesale price set by marginal generator with emission rate of 0.4 metric tons per MWh.

For several reasons, the estimated values shown in Table 1 may err significantly in either direction. This analysis may overstate the windfall potential in the early years of a cap-and-trade program because many deliverers would be constrained by the prices specified in long-term contracts. As those contracts expire, the deliverers would be able to renegotiate and take advantage of the higher price of the marginal generators. The windfall potential could eventually be much higher than the estimates shown if allowance prices increase much above $20 per ton. This analysis also did not take into account the customers of ESPs and other market-dependent POUs. This table is intended as illustrative only to indicate the potential order of magnitude of this issue under an emission-based allocation.

Many countries in the EU have competitive wholesale markets, similar to the markets that provide power for the majority of California's load. Analysis of the experience in the EU ETS Phase I has shown that opportunity costs were in fact reflected in electricity prices even though more than 95% of the allowances were allocated freely on a historical emissions basis. In Germany and the Netherlands, which both have competitive wholesale electricity markets, pass-through of the value of freely allocated allowances was found to range from 60% to nearly 100% (Sijm, Neuhoff and Chen 2006). In the UK, the MAC report states that generators in the electric sector benefited from £500 million in windfall profits in the first year alone (MAC 2007, p. 56). A report produced for the UK government estimated that

[17] Los Angeles Department of Water and Power is not shown since it is fully resourced and wholesale purchases are only a small percentage of its total generation.

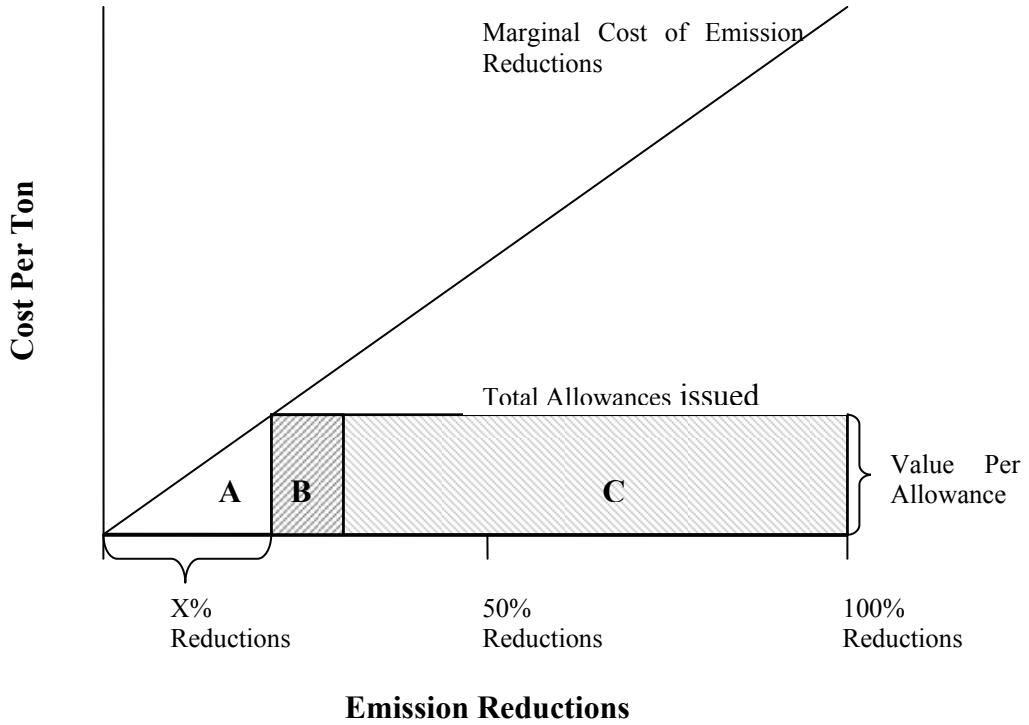
[18] It does not matter if some of the generation comes from zero-emitting resources that have no compliance obligation; deliverers of power from those resources still benefit from the increase in the selling price of the marginal generators as consumers will pay the market clearing price.

annual windfall profits in the electric generation sector would exceed £800 million annually (IPA Consulting, 2005). Point Carbon (2008) estimates that emission based allocations to electric orororgenerations in the UK will yield £6-15 billion in profit increases resulting from the pass-through of carbon allowance value during Phase II (2008-2012) of the EU ETS.

The State may determine that some compensation to existing entities is appropriate to compensate them for the cost of compliance-related expenditures and to avoid negative impacts to entities for investment decisions made prior to GHG regulation. However, as both the theoretical literature and recent experience with the EU ETS demonstrate, emission-based allocation can result in regulated entities receiving allowance value far in excess of the cost of regulation (Sijm, Neuhoff, and Chen 2006; NCEP 2007; Cramton and Kerr 2002; Bovenberg et al., 2003; Burtraw and Palmer 2007; Burtraw, Palmer, and Kahn 2005).

A free allocation would likely result in large profit increases for deliverers who are not also retail providers. Figure 3 helps demonstrate this point, showing the costs of mitigation and value of allowances under an emission based allocation method. The upward sloping line represents the marginal cost of reducing emissions. It assumes that early reductions can be made at minimal cost and that the cost of emission reductions increases linearly with each additional unit of emission reduction. This example assumes that the State is requiring industry-wide reduction of emissions by X percent. The total cost of reaching X percent of emission reductions is equal to the area of the triangle A.

Figure 3. Illustration of Relationship between Allowance Value and Cost of Compliance



Under an emission based allocation, firms would receive allowances equal to the level of emissions they are allowed to emit. The value of these allowances will be equal to the marginal cost of the last unit of emission reduction. Shown graphically in Figure 3, the total value of these allowances would be equal to the area of the shaded rectangles B and C. As the graph shows, the value of the allocated allowances far exceeds the total cost of emission reductions, represented by triangle A. During the early years of the cap, when reduction requirements are low, the cost of emission reductions are small relative to the value of the allowances issued.

Compensating the entire industry for the cost of carbon emission regulation can be accomplished by freely allocating a fraction of the total available allowances. Rectangle B in Figure 3 represents an area equal to triangle A, the cost of compliance. By freely allocating allowances equal to rectangle B, the State can compensate the industry for their cost of complying with carbon emission regulations.

Staff notes that in light of the EU's experience with windfall profits, EU leaders are considering methods of transitioning the electric sector away from the current emission-based system used under the EU ETS. The European Commission is evaluating the use of full auctioning in Phase III, particularly in the electric sector because it is not subject to

international competition (European Commission 2008, pp.7-8). [19] The Environmental Audit Committee of the UK House of Commons urges the UK Government to press for full auctioning of allowances in the future and that in particular the electric sector should be subject to 100% auctioning in Phase III (UK House of Commons EAC 2007, p.53).

When allowances were distributed for SOx emissions under the Acid Rain program, circumstances differed markedly from the current electricity market structure in California. Allowances in the Acid Rain program were allocated to regulated electric utilities. As these utilities were subject to rate regulation, they were not able to capture the value of allowances in the form of higher consumer prices. As a result, the price effects of carbon pass-through were limited under the Acid Rain program (Cramton and Kerr, 2002).

Staff has identified several key impacts that would result under a pure emission-based allocation. Below is a summary of our analysis of a pure emission-based approach using the four evaluation criteria:

- The degree to which opportunity costs are passed on to customers is related to the portion of power that their retail providers purchase from the market and the change in the wholesale power price. To mitigate price increases the governing boards (or other regulators) of fully-resourced, vertically-integrated utilities are unlikely to allow pass-through of the value of allowances, while independent deliverers will pass opportunity costs through to retail providers who purchase power in wholesale markets. The market-dependent retail providers (IOUs, ESPs, and some POUs) will have to recover these higher costs by raising retail rates. The pass-through cost of carbon allowances can result in a large transfer of wealth from customers to deliverers of independent generation.

- Emission-based allocation would not result in large transfers among customers of retail providers.

- With regards to administrative simplicity, emission-based allocation is likely to be more complex to administer than an auction system. These challenges are related to determining a baseline period and estimating the emission levels associated with the generation of each deliverer.

- Under a historical emission-based allocation, new entrants face a competitive disadvantage. New entities participating in the market would need to purchase allowances, while their existing competitors would receive them for free. Allowances can be set aside for new entrants, but this increases the administrative complexity of the program. If not designed carefully, providing free allowances to GHG-emitting deliverers could encourage development of fossil-fuel generation, causing firms to invest in emitting resources over non-emitting resurces that might otherwise be more attractive investments without the free allocation (Ahman, Neuhoff and Chen, 2006).

[19] Where energy-intensive sectors face competition from uncapped jurisdictions, if the allowances needed for that sector were only available by purchase at auction, that cost might induce leakage, thereby undermining the objectives of the cap-and-trade program. Administrative allocations to these sectors can mitigate this problem.

5.3 Preferred Emission-Based Approach

A pure emission-based allocation would almost certainly result in considerable windfall profits for independent (non-utility) deliverers in competitive wholesale markets. Because of this inherent trait of emission-based allocation, staff suggests that if an emission-based method is adopted, it only be used in combination with other approaches, in order to minimize the impact on consumers' costs. If the State decides to adopt an emission-based allocation, staff recommends that the system begin with a mix of emission-based allocation and auctioning or output-based allocation. Staff recommends that the system transition to either full auctioning or a mix of auctioning and output-based allocation over time.

Researchers have attempted to determine the share of allowances needed to compensate entities for the costs they face under a GHG cap-and-trade system. Harrison et al. (2007) surveyed studies and models that explored the compensation requirement to offset the costs for entities in the electric sector. Of the 11 studies sampled, they found that compensation for the electricity sector required between 5-50% of allowances. The wide range of results can be attributed to different data sets, compliance regions, allowance price assumptions and other variables. These studies generally considered the overall sector-wide compensation required. Only one of these studies considered lifetime compensation requirements, while the rest focused on compensation required over a limited program duration. Actual compensation at the firm level would likely vary considerably even if sector-wide compensation was accommodated by an allocation system (Harrison et al., 2007; Burtraw and Palmer 2007). According to the National Commission on Energy Policy report, freely allocating 50% of allowances based on historical emissions – with the remaining allowances auctioned – would be necessary to fully compensate entities in all sectors of an economy-wide system, though they do not consider the specific compensation required for the electricity sector (NCEP, 2007). Stavins (2007) also finds that 50% free emission-based allowances, coupled with a declining allocation over 25 years, approximately compensates entities of all sectors in an economy-wide system.

Staff recommends that, if adopted, an emission-based allocation in the electricity sector begin with no more than 50% of allowances provided freely to deliverers based on historical emissions. Under this proposal, the average annual allowance level would approximately equal the average level of "required" compensation among the studies considered by Harrison et al (2007). This level would substantially offset the costs faced by deliverers during the crucial early years of the cap and trade program, allowing entities time to adjust production and identify cost-effective mitigation strategies.

If this approach is pursued, the amount of emission-based allocation should decline each year and cease altogether within a few years. As a starting point, Staff recommends that the emission-based allocation decline 10% per year and completely end in year 6 (see Table 2). This recommendation would mitigate the windfall profit issues associated with long-term emission-based allocations.

Table 2. Suggested Transition Schedule if Emission-Based Allocation is Adopted

Year	Percent of Allowances Allocated based on Emissions	Percent of Allowances Allocated by Auction or Output-Based
2012	50%	50%
2013	40%	60%
2014	30%	70%
2015	20%	80%
2016	10%	90%
2017 +	0%	100%

Under this approach, California would need an alternative method or methods for allocating those allowances not distributed based on historical emissions. Staff recommends that the State consider output-based allocations or auctioning as possible means of distributing allowances. Both output-based allocation and auctioning avoid the potential for large-scale additional profits accruing to independent deliverers. The elements of these allocation systems are described below in Section 6 and Section 7. In the Interim Opinion, the Commissions recommended that at least some portion of allowances should be auctioned. Thus, if any output-based allocation were to be used, allowances would be allocated by three different methods in the early years of the program. The use of three different allocation methods would increase the administrative complexity of the program.

Staff finds the need for a rule on plant closures and new entrant accommodations to be unnecessary under this proposal. While such rules have been adopted by most Member States in the EU, the low initial share and decline in emission-based allocation under this proposal would reduce the equity and competition concerns that a closure rule and new entrant accommodation are aimed at addressing. The large percent of auctioned or output-based permits provide new entrants with an opportunity to meet their allowance needs. While equity concerns are the most frequently cited need for ending historically-allocated allowances when a plant ends production, these concerns would be mitigated by the fact that emissions-based allocations would be gradually phased out after 5 years.

6. Output-Based Allocation

6.1 Mechanics

With output-based allocation, allowances would be distributed freely to eligible deliverers based on the MWhs delivered to the California grid. As discussed previously, staff recommends that the allocation be updated periodically if this approach is adopted. In contrast to the emission-based approach, continued allocation of output-based allowances would depend on continued deliveries of electricity. Each eligible unit of power delivered to the grid would receive allowances at some rate per MWh such that the sum of allowances allocated equals the cap.

Output-based allocation of a fixed number of allowances is distinguished from a 'benchmarking' allocation system. This paper recognizes an output-based system as one that allocates a set amount of allowances to deliverers in proportion to their deliveries in a previous year. Under a benchmarking system, each unit of eligible generation would receive allowances at an administratively-set allowance rate.

While these systems appear similar, one key difference between these allocation methods is that a benchmarking system lacks a firm cap. A benchmarking system utilizes an allocation rate that is set administratively based on projected load, forecasted deliveries of hydropower, and the estimated production from GHG-emitting resources needed to meet load. Unanticipated variations in production from emitting facilities would result in the total allowance levels fluctuating higher or lower than the intended cap. State regulators could attempt to match the cap on average by adjusting future emission rates higher or lower, depending on the excess or shortage in total allowances issued.

In order to operate under a firm cap, output-based allocation must instead use a prior year's delivery levels to determine the allowance allocation for each deliverer. The following example, shown in Table 3, illustrates how an output allocation could function in 2012 where total generation is delivered by 3 entities – Deliverer A, Deliverer B, and Deliverer C. In this case, 2012 allowances are allocated based on deliveries in 2011. Deliverer A delivered 50% of the electricity in 2011 and therefore receives 50% of the allowances for 2012. Deliverers B and C receive smaller portions of the total allowances in 2012, 37.5% and 12.5%, respectively. These allowance portions are multiplied by the 2012 allowance cap to determine the total allowances received by each firm.

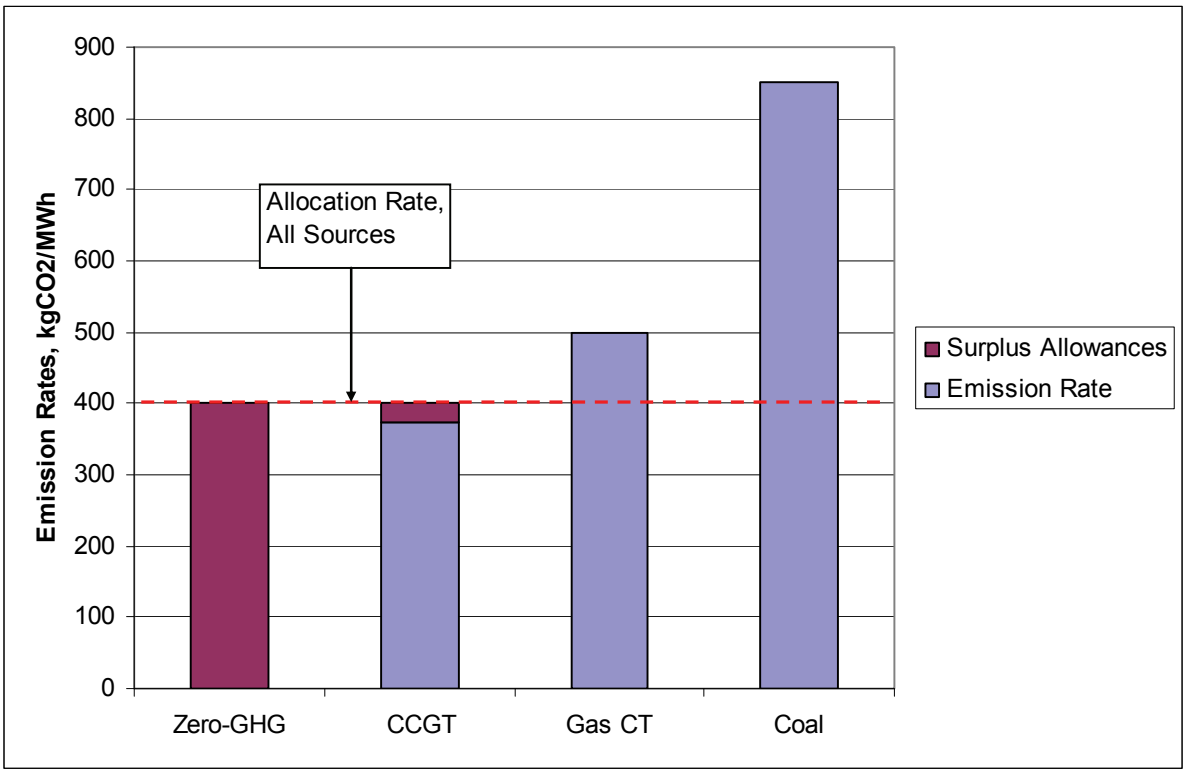
Table 3. Hypothetical Output-Based Allocation to Deliverers

	Deliveries in 2011, Million MWh	Share of 2011 Deliveries, Million MWh	2012 Allowances Received, Millions of Tons (Cap = One Hundred Million Tons)
Deliverer A	100	50%	50
Deliverer B	75	37.5%	37.5
Deliverer C	25	12.5%	12.5
Total	200	100%	100

6.2 Analysis of Pure Output-Based Allocation

Under a pure output-based allocation, all deliverers would receive allowances based on power delivered to the grid. In this example, we use allocation of a fixed pool of allowances based on deliveries in a prior year. Deliverers would receive freely allocated allowances in one period in proportion to their deliveries to the California grid in a previous period. On an annual basis, the allowance level would be updated to reflect changes in the total generation levels as well as the changes in the cap. As the cap declines, the amount of allowances per unit of generation would also decline, assuming the power delivered does not decline as well.

Figure 4. Example of a Pure Output-Based Allocation Method



In this formulation, for each MWh delivered to the grid, a deliverer would receive the same number of allowances. Using 2004 as an example, California generators produced approximately 195 million MWh and gross imports totaled another 98 million MWh, yielding 293 million MWh generated for deliveries to the California grid. According to the inventory approved by ARB on December 6, 2007, total GHG emissions in 2004 associated with in-state generation and gross imports were approximately 117 million metric tons carbon dioxide equivalent ($MMTCO_2e$).[20] If the electric sector had a cap with an allocation that matched emissions in 2004, allowances would have been allocated at the average emission rate of 0.4 metric ton CO_2e per MWh. as Figure 4 shows, generation delivered from simple cycle combustion turbines and coal-fired sources would be short of allowances for each MWh delivered. Deliveries from efficient combined-cycle gas turbines and zero-emitting resources would receive surplus allowances for each MWh generated.

Unlike emission-based allocation, output-based allocation does not result in a large transfer of wealth from customers to deliverers. Under an output-based allocation, deliverers will find that they have an incentive to increase their delivery levels. Higher delivery levels ensure that deliverers will continue to receive valuable allowances in future years. In order to maintain sales, deliverers are likely to find that they cannot pass on the entire value of their allowances.

Consider the example of deliveries from the power plant discussed in Section 5.2. Because it may be more intuitive to understand, a benchmarking allocation method is used for purposes

[20] The values for both generation and emissions include electricity consumed for on-site use at CHP facilities.

of this example. The plant emits 0.5 metric tons of CO_2e for every MWh generated and has a marginal cost of $70 per MWh. Assume further that the benchmark rate is also 0.5 metric tons of CO_2e per MWh. Instead of receiving free allowances in perpetuity, under a "benchmarking" system the deliverer would only receive allowances equal to 0.5 metric tons CO2e for every MWh it delivers. If the plant produces and the market clears at $80 per MWh, the plant will earn $10 per MWh. There would be no allowance cost in this example since the plant's emissions will exactly be covered by the amount of the allocation it receives. In contrast to the emission-based example, if the plant does not produce electricity, it earns nothing because it would not receive any allowances to sell. The firm would not have an incentive to shut down or reduce generation, since it loses its allocation if it does not produce. Under a fixed-cap output-based allocation, the same incentives apply. Passing on the entire value of the allocation would risk diminishing its sales, which could be lost to lower-priced competition or reduced consumer demand. In this way, output-based allocation results in lower prices than emission-based allocation.

Numerous research studies support the conclusion that output-based allocation results in lower energy price increases relative to other emission-based or auction allocations.[21] Studies by Burtraw et al. (2001 and 2005) and Fischer and Fox (2004) indicate that output-based allocation results in only slight electricity price increases, significantly below the price increases under emission-based allocation and auctioning (assuming there is no revenue recycling). The Burtraw et al. 2001 model of a national cap and trade program found that output-based allocation resulted in the lowest electricity prices when compared to historical emission-based allocation or auctioning (again, assuming no revenue recycling). The 2005 study conducted for the Regional Greenhouse Gas Initiative (RGGI) region also found relatively low electricity prices under an output-based allocation. By incentivizing a higher level of consumption, these lower prices come at the expense of total economic efficiency (see Section 2.1). Allowance prices are higher as a result.

In its analysis of the pure output-based allocation method, staff identified the following impacts:

- Output-based allocation results in lower customer costs than emission-based allocation. Upward price pressures are mitigated by providing incentives for low emitting resources to increase production and deliveries to the grid.

- A pure output-based allocation would likely result in a large redistribution of money from customers of retail providers that depend on high-GHG sources of power to less GHG-intensive retail providers.

- A pure output-based allocation system can be administered with a simple formula and straightforward reporting requirements.

- A pure output-based allocation easily accommodates new market entrants.

[21] Note that these studies did not consider the possibility of recycling auction revenues back to retail providers.

6.3 Variations on Output-Based Approaches

Output-based allocation may be modified in several ways to meet various policy goals. We discuss some of these variations below.

6.3.1 Benchmark versus Cap

As described above, output-based allocations can be awarded based on a set rate to each unit of electricity delivered to the grid. This option effectively eliminates a hard cap and allows total emissions to fluctuate annually. Alternatively, output-based allocations can be awarded under a set cap level based on past years' production levels.

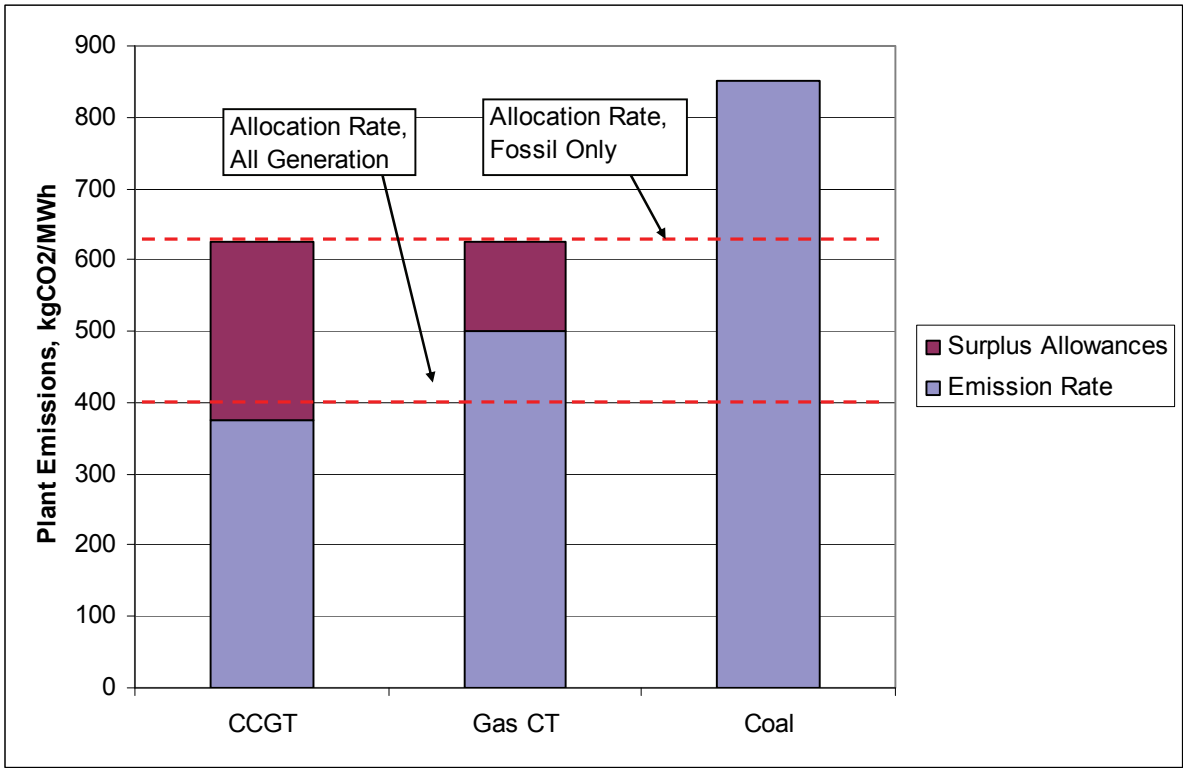
6.3.2 Updating Methodology

When a fixed cap approach is used, output-based allocation requires a methodology for determining the frequency of updating and the length of the baseline period. Updating can occur annually, with the shares of allowances allocated to each deliverer changing each year, or the updating period can last several years, with allowances issued based on the same baseline period for several years. The baseline period can be a single year, or an average of several years' deliveries can be used. More frequent updating helps support new entrants by providing new deliverers with free allowances after only a short period of operation. Updating on a rolling multi-year period could provide more stable allowance allocations to deliverers, but would also delay allowance allocations to new entrants.

6.3.3 Restriction of Generator/Deliverer Eligibility

Output-based allocation can exclude certain non-emitting deliverers – such as nuclear or hydro generation – or limit the allocation to emitting fossil fuel deliverers only. Under these scenarios, allocations per unit of fossil fuel generation will increase, increasing the incentive to deliveries from natural gas and reducing the cost of compliance for coal-fired generation, compared to allocation to all sources. This is depicted in Figure 5.

Figure 5. Example of a Fossil-Only Output-Based Allocation



Limiting allowance allocation to deliveries of fossil fuel generation would eliminate some allocation uncertainty for GHG-emitting deliverers. Some non-emitting deliverers – such as hydropower facilities – are subject to large fluxes in annual generation. Under an all-generation allocation, these annual generation changes could result in large, unpredictable changes in annual allowance allocations to GHG-emitting deliverers. Limiting allocation to fossil fuels would reduce the impact of generation changes from non-emitting deliverers, providing more certainty to generators regarding future allocation levels.

Limiting output-based allocation to fossil fuels presents some administrative challenges. Unspecified power would need to have an underlying resource mix identified in order to determine eligibility for allowances. The inability to identify the resource mix of some imports could give electricity importers an incentive to contract shuffle, shifting low-carbon fossil fuel generation into the state, to replace generation from non-emitting resources, in order to receive allowances. In the process of estimating supplier-specific or regional default emission factors, some identification of the underlying resources will be necessary. This information could be used to allocate allowances to unspecified power. For example, if future analysis of the resource mix used to provide power to California from the Northwest determined that on average, 30% of the MWhs were generated from fossil fuel sources, every unspecified MWh from the Northwest would count as 0.3 MWh for purposes of allocating allowances in proportion to recent generation.

Fossil fuel-based allocations place renewable development at a competitive disadvantage. Since gas-fired generation would receive revenue from the surplus allowances received, the price of gas-fired generation would tend to decline. Price increases of fossil fuel generation would help support renewable development, as most renewable energy sources are more costly than fossil fuel generation. By diminishing energy price increases, output-based allocation can act to reduce incentives to develop renewable energy. Modeling results by Burtraw et al. (2001, 2005) support this conclusion.

6.3.4 Differentiated Allocation by Fuel Type

Output-based allocation methods can also be designed to distribute allowances on a differentiated basis among fuel types. This can be done using several categories of fuel and technology type; however, to simplify the analysis we explore a differentiation based only on two fuel types – gas and coal. Administration of a fuel-differentiated output-based allocation method would be more complex than a non-differentiated method because the allocation to one deliverer will depend not only on the total quantity of generation (or emitting generation) but also on the relative proportions of gas and coal-fired generation delivered to the California grid.[22]

With the additional need to allocate allowances to sssMWh from different fuel types at non-uniform rates, some sort of weighting factor would need to be developed for higher-GHG sources. This weighting factor might be based on the ratio of the emission rate of an efficient coal-fired plant to that of an efficient gas-fired plant. An example of how this would work in practice is shown in Table 4 below. In this example, there are 100 $MMTCO_2e$ of allowances allocated for the electric sector in 2012. Total fossil-fired generation in 2011 was 150 million MWh, with 100 million MWh from gas-fired sources and 50 million MWh from coal-fired sources. The weighting factor for coal-fired electricity is 2, based on the fact that coal plants emit approximately one metric ton of GHGs for every MWh produced and gas plants emit approximately 0.5 metric ton per MWh.

Table 4. Fuel-Specific and Undifferentiated Output-Based Allocation to Fossil-Fired Generation

Generation Fuel Type	Deliveries in 2011, million MWh	Share of 2011 Deliveries	2012 Allowances Received, Million	Weighted Deliveries in 2011, million MWh	Share of 2011 Weighted Deliveries	2012 Allowances Received, Million
Gas-Fired	100	66.7%	66.7	100	50%	50
Coal-Fired	50	33.3%	33.3	100	50%	50

In this example, assuming that 2012 deliveries are similar to 2011 deliveries, an undifferentiated allocation would result in deliverers of coal-fired generation having to purchase approximately 17 million allowances from deliverers of gas-fired generation. Under the fuel-specific allocation, deliveries from gas and coal generation would, on average,

[22] In reply comments to the October 15, 2007 ALJ ruling requesting comments on allocation issues, Kenneth Johnson provided a detailed overview of how fuel-differentiated output-based allocations can be implemented. Although his explanation is couched in a broader method that employs auctioning with output-based refunding, the fundamental principles still apply.

receive very near the number of allowances needed for compliance. The consequences of these two methods have interesting implications for cost to consumers and transfers among customers of different retail providers. The additional revenue that gas deliverers would receive from coal deliverers in the uniform allocation would allow gas deliverers to sell their output at a reduced cost. This would reduce consumer costs for customers of retail providers that are largely dependent on gas generation, but would raise consumer cost for customers dependent on coal-fired generation. The fuel-specific allocation could be designed to eliminate these transfers.

6.4 Preferred Output-Based Approach

Based on its analysis of the pure output-based allocation, staff recommends that an output-based allocation be limited to electricity delivered from fossil fuel generation sources. An 'all-generation' output-based allocation would provide a large amount of valuable allowances to deliverers of power from existing nuclear, hydropower and other zero-GHG plants. AllocatAllocatAllocatProviding allowances to these entities would provide no clear program benefits but would generate large amounts of revenue for these entities when they sell their allowances. Deliverers dependent on fossil fuel-generation would bear the cost of the payments, as they would need to purchase all or some of the allowances from these entities. This would produce a sizable transfer of wealth from customers of high-GHG retail providers to customers of low-GHG retail providers. An allocation only to fossil fuel-generated electricity delivered to California eliminates the distribution of revenue to non-emitting deliverers and reduces the compliance cost for deliverers of fossil fuel-generated electricity. However, a variation on this approach that warrants additional analysis is the inclusion of incremental generation from new renewable sources in the eligible generation. This approach would help counter the competitive disadvantage that renewables face under a fossil fuel-only output-based allocation method (Burtraw, Palmer and Kahn 2005).

If an output-based allocation limited to fossil fuel generated electricity is adopted, staff recommends an initial fuel-specific output-based allocation as described in Section 6.3. Differentiating the allowance rate between different fossil fuel technologies would reduce the redistributive outcomes among the customers of different retail providers. An output-based allocation granting allowances equally to deliveries from all fossil fuel generation on a non-fuel specific basis would likely result in deliverers of coal-fired generation purchasing large quantities of allowances from deliverers of gas-fired generation (or from an auction or other sectors). Since deliverers of gas-fired generation would receive surplus quantities of allowances, the price of deliveries from gas-fired generation would decrease (Burtraw, Palmer, and Kahn 2005). Therefore, retail providers that depend on a high ratio of deliveries from coal-fired generation relative to deliveries from gas-fired generation would have to pass through the embedded cost of allowances while retail providers that depend on a large ratio of gas-fired generation would benefit from lower electricity prices. Whether direct (deliveries from utility-owned generation) or indirect (deliveries from independent generation), a transfer among the customers of different retail providers would occur.

The fuel-specific output-based allocation faces administrative challenges similar to the uniform fossil fuel-only allocation related to power from unspecified sources. A fuel-differentiated output-based allocation would require detailed analysis of deliveries from

unspecified power during each baseline period, to identify the sources of the underlying generation.

Like other output-based methods, this allocation method would not inhibit new entrants from entering the market.

Staff recommends that, if an output-based allocation is adopted, it begin by allocating the majority of allowances based on output and transition over time to a 100% auction-based allocation. A suggested transition schedule is shown in Table 5. The transition to a 100% auction system would allow carbon markets to mature without subjecting consumers to potentially large price fluctuations in the early years of the cap-and-trade program. Transitioning would also allow the State an opportunity to develop sufficiently robust market oversight processes and allow deliverers and retail providers additional time to transition their resource mixes to reflect the new cost of carbon emissions.

Table 5. Suggested Transition Schedule from Output-Based Allocation to Auction

Potential Allowance Allocation Method		
Year	% Allowances Issued on Output Basis	% Allowances Issued by Auction
2012	90%	10%
2013	80%	20%
2014	70%	30%
2015	50%	50%
2016	30%	70%
2017	10%	90%
2018+	0%	100%

If the program does not transition to a large share of auctioning within a few years, it will be important to decrease the weighting factor for deliveries from coal-fired generation. In the longer term, the weighting factor raises significant efficiency concerns by shielding high-GHG sources of generation from the cost of pollution emitted, either through an opportunity cost or real cost of purchased allowances.

7. Auctioning

7.1 Mechanics

If allowances are auctioned, there is no need to determine a method of distributing the allowances to the deliverers required to have them. Allowances would be bought by regulated entities as needed in the auction or in the secondary market. In this paper, we do not yet delve into the finer points of auction design. If ARB decides to implement a cap-and-trade system that includes auctioning of some portion of the allowances, the Commissions may wish to assist ARB in the future by analyzing and providing recommendations to ARB on electricity sector-specific elements of auctions and ways to mitigate potential market manipulation.

For purposes of this paper, we assume that any actual auction that comes to pass would be conducted either by ARB or an auction agent under contract to and oversight of ARB. We do not propose that any entity in the electric sector have a role in conductingauctions, should they occur under the AB 32 framework.

Beyond this, we do address one other aspect of auction design that we believe merits early consideration. This relates to the fear that some parties have expressed that parties with financial interests could buy large amounts of allowances and hoard them in order to drive up future prices or otherwise "game the system." The RGGI auction design report concluded that inherent market features coupled with some straight-forward design features should be sufficient to prevent market manipulation. For example, Holt et al. (2007) suggest that no one entity should be allowed to purchase more than 33% of the allowances in any one auction. In the proposed RGGI design, the allowances for a given year would be auctioned over eight rounds with 12.5% auctioned in each round. No single entity would be able to purchase more than approximately 4.3% of a single vintage in any particular round. Attempts to hoard allowances would be detected before a large share of allowances could be acquired by any single entity, and appropriate steps could be taken to limit a party's future participation. The RGGI auction design report cites two advantages of open auctions: greater participation in the auctions encourages liquidity in the secondary market and provides a measure of protection against collusion or other manipulative behaviors.

If further analysis suggests that the California market is susceptible to manipulation, ARB may decide to limit auction participation, at least initially. In the interest of caution, ARB could conduct separate rounds of auctions in which the first lot is available only to entities with a compliance burden and a subsequent lot is available to all parties. Alternatively, ARB may wish to limit entities representing financial enterprises with no compliance obligation to a lower purchase limit than entities with a compliance obligation. Staff does not have enough information at this time to make a specific recommendation.

Instead of the auction mechanics per se, we focus in this paper on the disposition of the auction revenues. The Commissions state in the Interim Opinion that the majority of auction proceeds from allowances in the electricity sector should be used in ways that benefit electricity consumers:

> "As a starting principle, it is important that any policy for distribution of allowances provide that revenues from the sale of allowances be used primarily to benefit consumers in the energy sectors directly. This is because energy sources such as electricity and natural gas are vital commodities. Thus, we believe special focus is warranted for allowance allocation policy in the energy sectors."[23]

There are a variety of ways in which the auction revenues from the electricity sector could be preserved for the benefit of consumer purposes in the sector, either to aid in GHG reductions/mitigation or for consumer bill relief. One option would be to allocate allowances directly to retail providers of electricity, on behalf of their consumers, on some basis, but require those retail providers to offer up their allowances during the auction. In this way, retail

[23] D.08-03-018, p. 8.

providers would receive the proceeds from auctioning of their allowances directly, with the funds raised to be used to benefit their consumers. As with the free allocation methods described earlier in this paper, allowances could be granted to retail providers on a variety of bases, including historical emissions (based on their resource portfolio mix) or sales of electricity to consumers.

The advantage of this type of approach would be in the efficient distribution of auction revenues directly to retail providers on behalf of their consumers. This is the approach that most RGGI States are taking to distribution of allowance value.[24] Note that staff is not proposing that retail providers conduct the auction; as stated above, we assume that the auction itself would be run by ARB or its agent. Retail providers would simply be required to offer up their allowances at auction in order to receive the revenues once the auction is conducted. Retail providers who are also deliverers would also need to purchase allowances in the same auction to cover the emissions associated with their electricity deliveries.

Another option is for no actual allowances to be allocated prior to the auction, but instead for retail providers to be granted auction revenue rights on some basis entitling them to the proceeds from the auction. TTis the this option described for illustrative purposes in this paper.

We propose that the majority of revenues from the electricity sector's share of auctioned allowances be placed in a reserve account for retail providers.[25] We note that for retail providers with self-owned fossil-fired generation, particularly fully resourced utilities, payments for allowances successfully purchased at auction may present unproductive up-front cash flow problems as those same entities would be entitled to receive revenues from the auction as well. If the retail provider were actually required to submit payment for the entire block of allowances purchased, this could constitute a substantial payout for retail providers that are fully resourced, particularly those still dependent on coal facilities. This payment for allowances followed by the return of auction revenues to such retail providers from the reserve account would result in unnecessarily large payments by and to these utilities. Therefore, we recommend that deliverers that are also retail providers only pay for the net difference between their allowances purchased at auction and the revenues returned via their ARRs.

[24] While the RGGI model rule requires a minimum of 25% of allowances be auctioned for consumer purposes, the majority of states have stated an intent to auction 100% of allowances.

[25] See Title IV, Subtitle B of the "Lieberman-Warner Climate Security Act of 2007" (S.2191) reported from the Senate Committee on Environment and Public Works December 5, 2007 for an example of a proposed "carbon trust" established to manage auction revenues in an account separate from general revenues. It may be necessary for ARB to seek additional authority from the Legislature to establish a similar fund for the State of California.

Table 6. Example of Net Payments or Receipts at $20 per Metric Ton CO_2e

	Base Period Emissions, $MMTCO_2e$	Share of Base Period Emissions	2012 Emissions, $MMTCO_2e$	2012 Allowance Payments, Million $	Revenue from ARRs, Million $	Net Receipt/ Payment, Million $
Utility A	45.0	50%	50.0	1,000	1,000	0
Utility B	22.5	25%	27.5	550	500	-50
Utility C	22.5	25%	22.5	450	500	50

Examples of how the net payments would be calculated are provided in Table 6. In this example, all utilities are assumed to be fully resourced and vertically integrated. In this example, the total allocation to the electric sector covers the sector's emissions in 2012 and the auction revenues are returned to retail providers on a historical emission basis (described below). The emissions of both Utility A and Utility B have grown since the base year, whereas Utility C has managed to keep emissions constant. Since Utility A's emissions have grown at the average rate, its share of emissions in 2012 is the same as its base year share. Utility A makes no payment in 2012 because the $1 billion in ARRs match the $1 billion for allowances to cover its emissions. Utility B's emissions have grown faster than the average rate, so its emission-based ARRs do not fully cover its need for allowances. The net payment by Utility B is $50 million. Utility C's emissions have not grown, and it receives a net payment of $50 million.

7.2 Rationale for Retaining Auction Revenue in the Electricity Sector

Staff suggests that there are three persuasive reasons for retaining a large share of any auction revenues for consumer benefit in the electricity sector. First, electricity consumers in California are currently paying, and will continue to pay, a variety of public goods charges that are directly climate related. As stated in the Interim Decision, the principal sources of direct GHG reductions in the electricity sector in the near term come from investments in energy efficiency and renewables. Retail providers are currently the principal service providers for these investments. Since ambitious energy efficiency and renewable goals are mandatory for California's retail providers, it would be redundant to have retail providers paying for mandated reductions and the total embedded allowance cost of purchasing or generating power. As the absolute minimum, auction revenues sufficient to offset the total expenditures expected for these programs should be retained within the sector, to be expanded as additional cost-effective measures are identified.

The second reason is that, as stated in the Interim Opinion, electricity is a vital commodity. The average retail rate in California is roughly 40% higher than the average national rate. Electricity costs are considered regressive by some because lower-income consumers spend a higher proportion of their income for electricity compared to higher-income consumers. As GHG emissions costs put upward pressure on retail rates, lower-income households may bear a disproportionate burden; thus, some bill relief is desirable, especially for low-income households. If GHG costs were not at least partially dampened, they may induce some degree of leakage because businesses might choose to relocate elsewhere. Leakage would undermine the goals of the GHG program because real reductions in GHGs would not occur. Thus, staff

believes that some portion of the allowance value should be allocated to retail providers for bill relief.

The third reason is that most customers are served by regulated utilities which have extensive public oversight from either the Public Utilities Commission or their local governing boards. Such firms cannot unilaterally pass GHG related benefits to their shareholders or use them to invest in other types of commerce. Regulated entities can be held accountable for spending their funds in a manner directed to meet the goals and timelines of AB 32.

Beyond retaining auction revenues within the electricity sector, it would be possible to return some of the revenues to the particular retail provider from which they came. These funds could be required to be used for energy efficiency, renewable, and other emissions reduction programs. This approach has the advantage of minimizminimizing any transfers among customers of retail providers.

It is also important to understand that in a market-based system, the fact that a retail provider may spend more money on GHG allowance costs (whether directly or embedded in the power it purchases from the market) than it receives in recycled revenues does not necessarily mean that it has suffered from being in a cap-and-trade system. If its own cost of reducing emissions is greater than the price of allowances, a retail provider would actually best serve its customers by purchasing more allowances than the number of ARRs assigned to it. The example below describes a fully-resourced utility, but the same reasoning applies to other retail providers as well.

Assume that a utility is emitting 100 tons of GHGs in 2012. This utility has received an allocation of 100 allowances (or ARRs for 100 allowances) in 2012, which precisely matches its emission level in the first year of the program. The number of allowances it receives will decline to 80 allowances by 2020. It is now 2017, and allowances are trading around $50 per ton. This utility determines that it will be able to reduce emissions to 85 tons by 2020 at a cost of less than $50 per ton, but reductions from 85 to 80 tons will cost $70 per ton. This utility has a choice to make. Should it try to stay within the allocation that it will be given by the State in 2020? It could, but that would cost its ratepayers an additional $100 compared to reducing its GHG intensity only to 85 tons and buying 5 allowances. In this example, the utility may decide to purchase allowances beyond its allocation, but it is better off by being in a cap-and-trade system than if it were given a cap with no trading allowed. (Conversely, if this utility had lower-cost reduction options and could achieve reductions below 80 tons of GHGs for less than $50 per ton, it would benefit from receiving more money from auction revenues than it spends on allowances, which it could not do if there were no cap-and-trade program.)

As long as the State assigns ARRs to retail providers according to a schedule of emission reductions that are reasonably attainable, no single retail provider will be disadvantaged by participating in a cap-and-trade system compared to an alternative scenario in which individual caps are established. If one retail provider finds that reductions are more expensive than anticipated, and allowances are trading at a price that is less than its cost of abatement, it has the opportunity to benefit from the presence of the market and buy additional allowances, thereby saving its customers money.

7.3 Analysis of a Pure Auction Method

The Interim Decision does not endorse starting with 100% auctioning, and staff does not recommend such an approach. However, we present it here to illustrate the features of an auction method, before that method is adjusted to take into account California's needs and priorities. It is difficult to describe the implications of theoretically beginning the program with 100% auctioning without considering the use of the revenues generated. For purposes of illustrating a "pure" auction method, we first assume that *none* of the auction revenue is refunded to retail providers for customer benefit. How would this approach fare using the evaluation criteria?

- Auctioning of allowances without refund of auction revenues to retail providers would increase consumer costs substantially because deliverers would have to recover the cost of the allowances in their bid prices, contracts, or retail rates. The expenditures for allowances would constitute a transfer from deliverers (and ultimately consumers) to the State. Additionally, deliveries from low-GHG resources that are not owned by California retail providers (such as imports of low-GHG power from the Northwest) would benefit from some windfall profit due to the increase in wholesale prices. Choices about how auction revenues are spent can reduce the total social cost of the program. For example, auction revenue could provide additional economic efficiency gains if the revenues are used either to offset distortionary fees or taxes or to make public investments with a high rate of return (Smith and Ross 2002; Roland-Holst 2006)[26] Since, in this example, none of the auction revenues would be returned to retail providers, no direct sstransfer among customers of retail providers would occur. However, if the State spends the auction revenues in a way that provides benefits relatively evenly across the state, an indirect transfer from customers of high-GHG retail providers to customers of low-GHG retail providers does occur. Assuming this to be the case, large redistributive impacts among retail providers' customers would be likely.

- Without consideration of administrative requirements associated with thethetherevenue return of auction ss to retail providers, auctioning is an administratively simple method because no baseline needs to be calculated, and load migration is not an issue.

- Auctioning easily accommodates new entrants.

[26] As discussed previously, stakeholders are concerned that any auction design would need to be carefully designed to protect against market manipulation. This issue will need to be addressed by ARB if it makes a determination in the scoping plan that an auction is appropriate.

7.4 Variations on Auctioning with Revenue Retention

We now examine two methods of allocating auction revenue to retail providers that have been proposed in this proceeding, emission-based allocation and sales-based allocation.[27] This recycling would be accomplished by assigning ARRs to the retail providers.

Table 7 provides an illustrative example of how these two approaches might work in practice. In this example, it is assumed that ARB has allocated 100 million 2012 vintage allowances for the benefit of the electric sector, representing roughly the projected level of emissions in that year. The auction clears at $20 per allowance, yielding $2 billion in auction revenue to be allocated among retail providers. Using the emission-based allocation of revenues, Utility A, whose power purchased or generated to serve its customers emitted half of the base year emissions, would receive half of the revenues, or $1 billion. The other two utilities, each of whose power emitted one-fourth of the total base year emissions, each receive $500 million.

Table 7. Revenue Redistribution, One Hundred Million 2012 Vintage Allowances Auctioned at $20 per Metric Ton CO_2 Equivalent

Retail Provider	Base Year Emissions, $MMTCO_2e$	Share of Base Year Emissions	2011 Retail Sales, GWh	Share of 2011 Retail Sales	Rev, Emission-Based ARRs, Million $	Rev, Sales-Based ARRs, Million $
Utility A	45.0	50%	60,000	30%	$1,000	$600
Utility B	22.5	25%	50,000	25%	$500	$500
Utility C	22.5	25%	90,000	45%	$500	$900

Using a sales-based approach, each utility would receive the revenues in proportion to a previous year's sales. In this example, a retail provider receives $10 from auction revenues for each MWh of load served. Because the emission rates associated with the power used to serve each retail provider's load differ significantly, the two methods of assigning ARRs produce widely divergent results. Because Utility A's share of 2011 sales was only 30%, it would only receive $600 million. Utility B would receive the same amount of revenue under either approach, and Utility C would receive $400 million more under the sales-based approach.

A sales-based allocation of ARRs in 2012 might lead to a large redistribution from coal-dependent retail providers to less GHG-intensive retail providers. In fact, the effect is likely to be identical to a pure output-based allocation. Coal-dependent retail providers might be saddled with rate increases due to GHG allowance costs in the first year of the cap. Assigning ARRs on the basis of retail providers' historical emissionswould produce strikingly different results, with little potential for wealth transfer among customers of different retail providers at the beginning of the cap-and-trade program.

[27] In comments NRDC/UCS indicated allocation of allowance value on a sales basis could inadvertently discourage energy efficiency activity (Opening Comments to the October 15, 2007 ALJ Ruling). As a remedy, NRDC/UCS propose that any sales-based method should also allocate allowance value to verified energy efficiency savings. Thus, "nega-Watt hours" would receive an allocation of auction revenues on an equal basis with actual MWhs sold. Allocating ARRs for energy efficiency may complicate the GHG program although more analysis of the incentive effect would need to be conducted before staff can provide a firm recommendation on this aspect of ARR allocation.

7.5 Preferred Auction Approach

In light of the consumer cost and redistributive impacts of a pure auction approach, staff developed a "preferred" auctioning scenario for discussion purposes. It involves auctioning 75% of allowances from the outset of the program. The remainder of allowances could be allocated to deliverers on an emission or output basis or used for purposes such as rewarding early voluntary action. As discussed above, this option is predicated on the condition that the majority of the allowance value is recycled to retail providers for the benefit of end users. Redistribution of allowance value to retail providers cccwould be accomplished by assigning ARRs to retail providers.

The discussion above illustrates that there could be large distributional effects that might arise from allocating ARRs on a sales basis. Staff concludes that this approach would constitute an unacceptable transfer from the customers of historically coal-dependent retail providers to other California customers. In this straw proposal, staff proposes that ARRs be assigned at the start of the program on a historical emission basis.

When the 2012 allowances are auctioned, the revenues from the auction would be distributed to the retail providers in proportion to their emissions from their entire portfolio in a base period. Auction revenues would be distributed on this basis as a proxy of the likely impact on the cost to retail ' customers' customersproviders . In reality, for retail providers that purchase electricity to cover most of their loads, the cost impact would be determined by the marginal generators that supply their power.

Over time, as retail providers are able to reduce their dependence on GHG-intensive power, the distribution of ARRs to retail providers could be transitioned to be based increasingly on sales. Given the information available at this time, it appears that approximately half of the ARRs could be allocated on a sales basis by 2020. A higher or lower proportion may be warranted based on further analysis. This will depend on conditions such as the degree to which access to hydropower or nuclear facilities gives some retail providers a capacity to deliver low-GHG power to their customers that is not available to other retail providers. Progress in developing and commercializing carbon capture and sequestration technology is another factor that might be taken into consideration.

Another option worthy of consideration would be to allocate ARRs on the basis of "net load"—subtracting out load or sales that are served by legacy investments in nuclear or large hydroelectric facilities.[28] This proposal may merit consideration as one approach that could guide the transition schedule away from emission-based ARR allocation.

Table 8 depicts one possible schedule for transitioning from emission-based assignment of ARRs to sales-based ARRs. Under this schedule, the allocation of ARRs would transition slowly from a fixed base period, historical emission basis in the early years of the program, with the rate accelerating to a sales basis in later years. The slower rate of transition in the

[28] This concept was introduced by Jim Lazar, a consulting economist for the City of Burbank, during comments at the November 5, 2007 joint Commissions' workshop on allocations in the electricity sector. Mr. Lazar defines this loosely as the "load minus that that's served by old, low-cost, noncarbon resources; big hydro and perhaps nuclear." See allocation workshop transcript, p. 137.

early years reflects the long lead time needed for investment in renewable energy and any transmission upgrades needed to deliver the power to loads. Additionally, some of the existing contracts that California retail providers have with out of state coal plants will not expire until several years after the implementation of the cap in 2012, making it difficult for coal-dependent retail providers to sever their reliance on these plants in the early period.

Table 8. Suggested Straw Proposal Transition Schedule of ARR Distribution

Allowance Vintage	Emission-based ARRs	Sales-based ARRs
2012	100%	0%
2013	95%	5%
2014	90%	10%
2015	85%	15%
2016	80%	20%
2017	70%	30%
2018	60%	40%
2019	50%	50%
2020	50%	50%

A transition schedule such as the one depicted in Table 8 could produce the "glide path" that some have discussed to encourage retail providers to transition away from reliance on carbon-intensive resources over time, while also regulating emissions directly at the deliverer level.

In sum, staff finds that the preferred auction design with initial allocation of ARRs on a historical emission basis results in low consumer cost and minimal redistribution among retail providers. Note that there is a trade-off between addressing consumer cost increases with emission-based ARRs and administrative simplicity. Setting up an emission-based ARR system would necessitate the creation of a historical baseline, similar to the process required for emission-based allocation to deliverers. However, setting baselines for retail providers would be further complicated by the need to assign generation to loads. This preferred design would be more administratively complex if load migration among ESPs or from ESPs to LSEs is accounted for. Additionally, some accommodation for retail providers with rapidly growing customer bases might also need to be evaluated.

8. Summary of the Allocation Methods

Table 9 summarizes how the different allocation methods described in this paper would perform compared to the identified evaluation criteria. For each basic method, both the pure version and the staff-preferred version are shown. Checks indicate that the method would generally perform well according to that criterion while an "X" indicates that it would perform relatively poorly.

Table 9. Summary of Evaluation Criteria Applied to the Allocation Methods

Allocation Method	Consumer Cost	Transfers among Retail Provider Customers	Admin Simplicity	New Entrants
Pure Emission-Based	✗/✓ [a]	✓	✓	✗
Preferred Emission-Based	✓	✓	✗	✓
Pure Output-Based	✓	✗	✓	✓
Preferred Output-Based	✓	✓	✗	✓
Pure Auction	✗	✗ [b]	✓	✓
Preferred Auction	✓	✓	✗	✓

[a] Emission-based allocation does not produce a transfer to producers for customers of fully-resourced vertically-integrated utilities.

[b] The degree of transfer among retail provider customers would depend on the dispensation of the auction revenues.

The pure emission-based allocation of allowances to deliverers would perform well for two of the evaluation criteria. The primary strike against a pure emission-based method is the risk of large windfall profits at the expense of most of the electricity customers in California served by IOUs, ESPs, and some POUs. An additional concern is that new entrants in electricity markets would be disadvantaged compared to deliverers that had been granted a perpetual allocation of allowances. These two concerns are both addressed in the version recommended by staff in which only half of the allowances would be granted on a historical emission basis with the rest distributed by auction or on an output basis, coupled with a rapid decline in the share of allowances allocated on a historical emission basis.

Both output-based methods would perform well in terms of holding down consumer cost. Any output-based approach with frequent updating also accommodates new entrants. The pure output-based approach differs significantly from the preferred approach with respect to transfers among the customers of different retail providers. While the pure output-based approach might result in significant transfers from the customers of coal-dependent retail providers in first year of the program, the preferred fuel-differentiated approach would produce virtually no transfers at the start of the program.

The evaluation of the pure auction approach with regard to consumer cost and transfers among customers of different retail providers is difficult without specifying what happens to the revenues from sale of the allowances at auction. If auction revenues in the pure auction approach were not used to mitigate consumer costs, auctioning would obviously have significant negative impacts on rates. Whether a large degree of transfer among customers of retail providers would occur, depends on how auction revenues would be used. The pure auction approach is the most administratively simple of all the methods examined. In the recommended auction approach, auction revenues would be distributed to retail providers on behalf of customers – initially on a historical emission basis and transitioning over time to a greater share allocated on a sales basis. This approach would reduce customer cost and mitigate the concern of transfers among customers of different retail providers but at the

expense of increasing administrative complexity. The preferred auction option would also readily accommodate new entrants.

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Allocating Allowances in a Greenhouse Gas Trading System

National Commission on Energy Policy

A STAFF PAPER FROM THE NATIONAL COMMISSION ON ENERGY POLICY

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Allocating Allowances *in a* Greenhouse Gas Trading System

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Disclaimer

This white paper was prepared by the staff of the National Commission on Energy Policy and aims to promote a better shared understanding of the issue of allocation. While this paper was drafted with the assistance of a sub-group of NCEP Commissioners, the views expressed here do not necessarily reflect those of each of the Commissioners of the National Commission on Energy Policy.

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Allocating Allowances in a Greenhouse Gas Trading System

Table of Contents

NCEP Commissioners IV

Letter from NCEP Co-Chairs V

Executive Summary VI

I. Introduction 1

II. Overview and Context 2

A. Allocation: what it is and why it matters 3

B. The difference between allowance costs and program costs 4

C. How allocation affects equity and incentives 6

III. Options for Allocations 8

A. Auction vs. free allocation 9

B. Use of allocation to advance other policy options 12

C. Allocation in existing programs and recent proposals 13

IV. Cost Equity as a Basis for Allocation 16

A. Determinants of cost incidence 16

B. Relationship of allocation to point of regulation 19

C. Cost incidence under the NCEP proposal 21

D. Implementation issues 22

V. Conclusions 24

References 28

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Clinical Professor of Business, Ross School of Business, University of Michigan; Group Vice President, Corporate Affairs, Ford Motor Company (2001 – 2004)

Letter from NCEP Co-Chairs

Dear Colleagues,

One of the most important recommendations in our 2004 report, *"Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges,"* was a proposal that the United States implement a mandatory, economy-wide program designed to slow, stop, and eventually reverse the growth of energy-related greenhouse gas emissions. Since we published that recommendation, our conviction that a response to global climate change must be part of any sound, long-term national energy strategy has only strengthened. More importantly, the same view is increasingly shared in corporate boardrooms and statehouses across the country, and in the U.S. Congress, where the Senate in 2005 passed a groundbreaking resolution expressing its support for a comprehensive policy that would limit emissions without harming the U.S. economy, while also encouraging comparable action by other nations.

As policy-makers, business leaders, and environmental advocates turn from the question of whether we need to address climate change to how we should go about it, more attention is being focused on the nuts and bolts of designing an effective, market-based program for reducing greenhouse gas emissions. In that discussion, the question of allocation—that is, how government distributes emissions permits or allowances under a trading program—emerges as one of the most critical and contentious of many design issues.

Recognizing the importance of allocation, the Commission has engaged in extensive further analysis and discussion of this topic over the last year. The results of that exploration are reflected in this staff White Paper, which aims to promote a better shared understanding of allocation: what it is, why it matters, and how policy-makers might go about designing an approach that is not only politically viable, but that fairly distributes the net burdens of regulation and seeks to maximize benefits to stakeholders and society as a whole. We are well aware that reaching a consensus on allocation will not be easy—the subject is inherently complex and many of the decisions involved are fundamentally distributional in nature, making them difficult to adjudicate in a manner that satisfies all parties. Moreover, allocation debates are easily confounded by misperceptions, common among many stakeholders, about how allocation decisions do and do not affect the way an emissions trading program works in practice.

It is our hope that this White Paper will help to clear up some of those misperceptions and provide the foundation for a new way of thinking about allocation. And as always we look forward to working with you, the reader, as this important debate evolves in the months ahead.

Sincerely,

John P. Holdren | William K. Reilly | John W. Rowe

Executive Summary

In 2004, the bipartisan National Commission on Energy Policy (NCEP) released a comprehensive set of energy policy recommendations that called for the adoption of an economy-wide, market-based program to begin slowing the growth of U.S. greenhouse gas emissions. Since the Commission's report was released, the impetus for mandatory national-level action on climate change has continued to build. Anticipating that a trading program will likely be adopted to limit domestic greenhouse gas emissions, interested stakeholders are increasingly focused on the specifics of designing and implementing such a program. Among the most important and contentious of many practical details to be addressed is the issue of allocation—that is, how should government distribute emissions permits or allowances under a trading program?

The question is contentious precisely because allowances represent a valuable financial asset. How this asset gets divided up among different interests and claimants turns out *not* to matter much, if at all, in terms of the environmental results or overall societal costs of the proposed policy. But political dynamics are rarely governed by aggregate considerations: specifically, who pays and who benefits and whether the outcome seems generally fair to most parties matters a great a deal. And in this regard, the importance of allocation can hardly be overstated.

Commission staff prepared this White Paper to help inform the ongoing debate about allocation by elucidating some of its less obvious but critically important aspects. Along the way, the Paper attempts to correct a number of common and persistent misperceptions that often get in the way of advancing the debate and to provide a theoretical and empirical foundation for the Commission's own evolving views. The results reflect further analysis conducted since the release of the Commission's 2004 report, as well as input gathered at a series of Commission-sponsored workshops on allocation and other critical program design issues in late 2005 and at a conference convened by the Senate Energy and Natural Resources Committee in April 2006 to explore many of the same questions.

These discussions and other recent developments—notably the European Union's (EU) experience with implementing an Emissions Trading System (ETU) for power plants and other large industrial emitters—have challenged certain

long-standing assumptions about allocation. In particular, they challenge the presumption that most allowances should be allocated for free to those industries that are directly regulated under a greenhouse gas trading program. As Senators Pete Domenici and Jeff Bingaman, then Chairman and Ranking Member of the Senate Energy and Natural Resources Committee, put it in a joint letter summarizing the common themes that emerged from their Committee's 2006 conference: "Allowances should not be allocated solely to regulated entities because such entities do not solely bear the costs of the emissions trading program."

Explaining why this is so and how one might design an allocation approach guided by equity considerations, in which the distribution of allowances roughly reflects the distribution of actual cost burdens under a greenhouse gas trading program, is the subject of this White Paper. As a starting point, several key points about allocation must be widely understood:

(1) **Allocation affects the distribution of benefits and burdens among firms and industry sectors; it does not change program results or overall costs.** Under a trading program, using an allowance is always costly—even for a firm that got the allowance for free—because it means giving up an asset that could otherwise be sold in the marketplace. Thus the incentive to reduce emissions is the same for all firms, regardless of allocation. Since allowances have real monetary value, they can be used to compensate firms or consumers without changing how different entities respond to the policy or what measures are taken to reduce emissions going forward.

(2) **The sum value of allowances is not a measure of the program's cost to society.** Under the original NCEP proposal, the market value of allowances in circulation in the early years of the program would total $30–$40 billion annually, while the costs incurred by society to actually reduce emissions would be much less (on the order of $4 billion per year). This is simply because the emissions target is relatively modest: the number of tons being reduced is much smaller than the number of tons for which allowances are issued. Trade in allowances generates costs for allowance buyers, but equal and offsetting gains for allowance sellers. It does not represent a cost to society.

(3) **The economic burden imposed on a particular firm or industry sector under a greenhouse gas trading program is not a direct function of its emissions or fossil-fuel throughput.** Rather, the burden depends on a number of factors, including ability to pass through costs, emission reduction opportunities, and elasticity of consumer demand for the firm's or sector's output in response to higher prices. Available analyses suggest that consumers and businesses at the end of the energy supply chain will bear the largest share of costs under a trading program, while primary producers or suppliers of fossil fuels (oil, coal, and natural gas) will bear a smaller share. Certain firms or industry sectors, however, may encounter more difficulty than others

in passing through costs and may bear a disproportionate burden as a result (examples might include firms that compete with foreign suppliers who do not face similar emissions constraints).

(4) Because they do not bear most of the cost, allocating most allowances for free to energy producers creates the potential for large windfall profits. Economic analysis and experience with Europe's trading system suggests that energy companies can and will pass most program costs through to consumers and businesses at the end of the energy supply chain. If the same companies get a large allocation of free allowances, the value of those allowances is likely to substantially exceed any actual net costs they incur as a result of the policy.

(5) Allocation decisions in the electric power sector are complicated by variation in the regulatory structures that govern this industry. Specifically, the co-existence of largely competitive wholesale markets and various forms of cost-of-service price regulation in different parts of the country could distort price signals in ways that blunt incentives to reduce end-use demand and lead to an inequitable distribution of cost burdens across consumers and companies in different regions. One concern is that program costs would be largely passed through to customers in competitive retail markets (allowing generators to "keep" most of the asset value of a free allocation), while companies operating in regulated markets could be required by regulators to use free allowances to offset price impacts. Since retail markets in the most coal-intensive regions tend to be regulated, this creates the potential for a perverse outcome in which consumers that rely on a more carbon-intensive generation mix see a weaker price signal than consumers that rely on a lower-carbon mix. Thus, policy makers will need to pay close attention to allocation decisions within the electric sector and should consider a variety of options to ensure rational and equitable results.

(6) Allocation provides an opportunity to advance equity and other broad societal interests without diminishing the price signal necessary to elicit cost-effective, economy-wide emissions reductions. A trading program works by creating market incentives—effectively attaching a price to every ton of carbon emitted. Giving away allowances won't shield firms or consumers from this price signal—indeed, that would not even be desirable. For the program to be effective, all energy producers and users must face the same incentive to reduce emissions. But allowances *can* be used for a variety of productive purposes: to compensate those who bear a disproportionate burden under the policy, to advance other public-policy objectives (such as supporting energy R&D), or to provide broad societal benefits (for example, making it possible to cut taxes on income or investment).

(7) A mixed approach, which combines some free allocation with a partial auction, may offer significant benefits. Giving away all (or nearly all) allowances to the energy companies that are directly regulated under the program would have the effect of transferring wealth from consumers to

> *"A 50 percent free allocation—from the total pool of allowances available on an economy-wide basis—would provide enough free allowances to substantially compensate adversely affected industries for un-recovered costs under an emissions trading program."*

those companies and would tend to produce large net profits for some firms. The opposite approach—auctioning all allowances and using the revenues for socially productive purposes—is far preferable from the standpoint of maximizing overall economic efficiency, but could leave some carbon-intensive industries with significant net costs.

All of the above points are discussed in some detail in the White Paper that follows. Taken together they lead the Commission to conclude that the allocation approach taken in Europe—where national governments distributed nearly all allowances for free to entities directly regulated under the EU trading system—does *not* provide a good model for an economy-wide U.S. program. Rather, to address equity concerns and avoid excessive windfall profits in some industries, a much larger fraction of emissions allowances or permits should be auctioned.

Based on analysis by the Commission, this White Paper concludes that an allocation guided by equity considerations would initially distribute no more than 50 percent of allowances for free to major energy producing or consuming industries, including directly regulated suppliers of primary fuels (coal producers, oil refiners, and natural gas processors), the electric power sector, and energy-intensive manufacturers.[1] This would leave 50 percent of allowances to be directed to public purposes, where public purposes could include mitigating impacts on low-income consumers; investing in low-carbon energy technologies and end-use efficiency; creating incentives for agricultural carbon sequestration; and reducing the federal budget deficit and/or supporting broader tax reforms. Over time, any initial earmarks for specific purposes will need to be re-evaluated, suggesting a finite limit to these expenditures and a transition to general fund contributions.

A 50 percent free allocation—from the *total* pool of allowances available on an economy-wide basis—would provide enough free allowances to substantially compensate adversely affected industries for un-recovered costs under an emissions trading program. *Within* that free allocation, equity considerations argue for distributing shares to individual industry sectors in a manner that roughly reflects the incidence of actual cost burdens. Those cost burdens, as noted above and throughout this White Paper, are not a simple function of emissions or fuel

[1] This figure is far smaller than the 90 percent free allocation to major energy producing or consuming industries contemplated in the Commission's original recommendations. As reflected in this White Paper, the Commission's views on allocation have changed as a result of further exploration and analysis.

> *"Given that cost burdens are not equal, there should be no presumption that different industry sectors are entitled to equal shares of allowances, either in absolute terms or as a fraction of their emissions or fuel use."*

use. Moreover, they are likely to be quite small for some sectors (such as the petroleum industry) that should have little difficulty passing through costs and relatively higher for other sectors (such as the electric power sector and some energy-intensive manufacturers). Given that cost burdens are not equal, there should be no presumption that different industry sectors are entitled to equal shares of allowances, either in absolute terms or as a fraction of their emissions or fuel use.

Since it will not be possible to distinguish winners from losers at the individual firm level, a 50 percent free allocation will undoubtedly result in some overcompensation to firms that will be competitively advantaged under a greenhouse gas trading program. The Commission believes this is an acceptable trade-off in the interests of addressing legitimate cost concerns among some industry stakeholders and to advance the prospects for reaching political consensus. Over time, however, as energy producers and energy-intensive industries have an opportunity to adjust to carbon constraints, the rationale for a free allocation diminishes relative to the considerable advantages of an auction that generates revenues for more productive and widely-shared societal investments. Hence, it would be appropriate to gradually diminish the portion of allowances distributed for free in future years and transition to a more complete auction.

The Commission is well aware that the debate about allocation in the context of a national emissions trading program for greenhouse gases is just beginning in earnest. An important question that will need to be addressed is how to handle allocation to entities *within* different sectors, especially in the electric power sector, which presents unique challenges for the reasons noted above. Here and elsewhere a vigorous debate on the points discussed in this White Paper lies ahead. That debate is likely to be difficult at many points since, as the Commission has repeatedly cautioned, there is no approach to allocation that can hold harmless all stakeholders or render entirely costless a policy for reducing greenhouse gas emissions; nor will there always be a clear objective basis for choices that are fundamentally distributional and political in nature. Nevertheless, it is the Commission's hope that this effort to clarify some of the key issues surrounding allocation will help to promote a foundation of shared understanding for future discussions.

I. Introduction

In December 2004, the bipartisan National Commission on Energy Policy (NCEP) released a report outlining a comprehensive set of recommendations for national energy policy (NCEP, 2004). Prominent among these recommendations was a proposal that the United States implement a mandatory, economy-wide program of tradable permits or allowances to limit greenhouse gas emissions. Subsequent to the release of the Commission's report, the U.S. Senate, in June 2005, adopted a resolution expressing its sense "that Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that (1) will not significantly harm the United States economy; and (2) will encourage comparable action by other nations that are major trading partners and key contributors to global emissions."

Before and since the adoption of the Senate resolution, discussions among policy-makers and interested stakeholders have increasingly focused on the specifics of designing and implementing a market-based approach to reducing greenhouse gas emissions. Draft legislation considered by the Senate Energy and Natural Resources Committee in the final weeks of debate around the 2005 Energy Policy Act, as well as several subsequent proposals—including a House bill recently introduced by Representatives Mark Udall and Thomas Petri (H.R. 5049)—have featured a program design similar to that outlined in the Commission's 2004 recommendations. Other recent developments—notably California's decision to require significant, state-wide emissions reductions by 2020 and efforts by several northeastern and mid-Atlantic states to cap regional power-sector emissions—suggest that momentum for mandatory climate programs is growing. As state and federal policy-makers grapple with the practical details of crafting an equitable and effective approach, allocation—that is, how government distributes emissions permits or allowances under a trading program—emerges as one of the most important and contentious of many program design questions.

This White Paper is about allocation: what it is, why it matters, and how policy-makers might go about designing an approach that is not only politically viable, but that fairly distributes the net burdens of regulation and seeks to maximize benefits to stakeholders and society as a whole. It begins by situating the allocation debate in the context of recent developments, including the results of a conference on climate-change program design issues held by the Senate Committee on Energy and Natural Resources in April 2006 and earlier Commission-sponsored work on related topics. Subsequent sections review the basics of allocation, including its relationship to incentives and costs, as well as the pros and cons of different allocation options. Having laid the groundwork for a more nuanced understanding of these issues, the White Paper goes on to describe a general approach to allocation that addresses disproportionate cost burdens while also creating a reasonable transition period for capital- and energy-intensive sectors like the electric-power industry. The conclusion provides specific recommendations based on the Commission's further exploration and current thinking on this critical topic.

II. Overview and Context

Recognizing the practical and political importance of allocation decisions, the Commission has, since the release of its 2004 report, devoted additional study to this specific issue and engaged numerous stakeholders in an intensive dialogue about the merits of different options. In late 2005, the Commission joined with the Edison Electric Institute (EEI) to sponsor a series of four workshops on allocation and other program design issues for market-based greenhouse-gas reduction strategies. These workshops were attended by an average of 130 participants representing non-governmental organizations, academic institutions, various industries, and government, and each featured multiple expert presentations. Drawing on the results of these workshops, Cambridge Energy Research Associates (CERA) prepared an in-depth report for the Commission on allocation and other key design questions in February 2006 (CERA, 2006).

Following release of the CERA report, the Commission participated in a conference, held by the Senate Energy and Natural Resources Committee on April 4, 2006, to explore critical issues for the design of a mandatory greenhouse-gas program. The Senate conference was attended by more than 300 people and elicited detailed written comments from over 160 organizations and individuals, including NCEP (GPO, 2006). On June 22, 2006, Senators Pete Domenici and Jeff Bingaman, then Chairman and Ranking Member, respectively, of the Senate Energy and Natural Resources Committee, released a statement indicating that they were encouraged—as a result of the conference—about the prospects for fashioning "reasonable policy solutions" to the problem of climate change (Senate Energy Committee, 2006). The statement also summarized key themes that had emerged at the conference and in related submissions to the Committee.

On the subject of allocation, in particular, Senators Domenici and Bingaman identified several emerging principles. First, that allowances should be allocated "in a manner that recognizes and roughly addresses the disparate costs imposed by the program." Second, that allowances should not be allocated solely to the companies that are directly regulated under a trading program because those companies "do not solely bear the costs" of the program. A third principle was that a portion of available allowances should be auctioned (or used for set-aside programs) to generate revenues for "climate-related policy goals or for other public purposes." The final principle identified by Senators Domenici and Bingaman was that an allocation approach should transition gradually over

time from a largely free distribution of allowances to use of an auction "as the predominant method" for distributing allowances.

The Commission's own thinking on the subject of allocation has evolved as a result of further study and evidence emerging from real-world experience with implementing greenhouse-gas trading programs, including recent developments in Europe. In fact, the Commission's current view accords closely with the general principles articulated by Senators Domenici and Bingaman in the foregoing excerpt from their joint statement. The remainder of this White Paper attempts to establish the theoretical and empirical basis for those principles and to explore their specific implications for future allocation decisions.

A. ALLOCATION: WHAT IT IS AND WHY IT MATTERS

Market-based environmental regulatory programs have become increasingly popular since 1990, when the United States first adopted a "cap and trade" approach to reduce national sulfur dioxide (SO_2) emissions. The same regulatory model has since been used to address other pollution problems and has emerged as a common design feature in nearly all recent proposals to mandate greenhouse-gas reductions. The basic mechanics are easy to describe: government introduces a new kind of currency in the form of allowances or permits[2] that entitle the holder to release a given quantity of the substance being regulated. Emitters must surrender to the regulator a sufficient number of allowances to cover their emissions in a reporting period. Entities either buy or are given allowances. They can "use" (and eventually surrender) those allowances to cover their emissions and they can sell any unused allowances to others or (in many cases) bank them for future use. In the case of a program to regulate greenhouse gases, allowances or permits would most likely be issued in tons of carbon-dioxide-equivalent emissions. Future emissions are then constrained by limiting the pool of available allowances.[3]

Once underway, a trading program—by definition—leaves entities free to buy and sell emissions allowances or permits as suits their individual best interests. But someone needs to decide how to distribute this new currency at the outset. Will the government sell allowances or give them away, or some combination of both? To the extent that some allowances are distributed for free, which entities get them? How many allowances does each entity get and how is this determined?

All of these questions are subsumed under the topic of allocation. How they are decided can be highly consequential in terms of the political viability of a particular proposal, even though—for reasons discussed at length in later sections of this paper—allocation decisions typically have little bearing on ultimate program outcomes or on the costs incurred by society to limit emissions. In any mandatory program, permission to emit—precisely because it is limited—has value. The more stringent the program, the more the pool of available allowances is constrained, and the more valuable each allowance becomes. Potential recipients have a direct financial stake in how this finite pool of new assets is to be distributed, both in terms of whether allowances will be given away vs. sold to the highest bidder and in terms of the share of total allowances available to a particular sector or individual firm. Any group or entity directly or indirectly affected by greenhouse-gas regulation can (and likely will) argue that it should be compensated in the form of free allowances: the list of potential claimants is diverse and virtually endless, but at a minimum is likely to include fossil-fuel producers, energy-intensive industries, electric-power producers, workers in affected industries (e.g., coal miners), states and local communities, consumers, and poor and minority households, among others.

[2] The term "allowance" was introduced in the SO2 program to avoid confusion with the term "permit," which has a well-established but somewhat different meaning in environmental law (where it is generally used in the more typical sense of written permission for a specific entity to undertake a specific action). Both terms are used interchangeably in the economics literature and in this Paper to denote permission to emit a defined unit of the substance being regulated in the context of an emissions trading program.

[3] In the case of the original NCEP proposal and subsequent draft legislation considered by the Senate Energy and Resources Committee, emissions technically are not capped. Rather, the price of allowances is capped via a safety-valve mechanism designed to make additional allowances available when the per-ton price of emissions reductions rises above a threshold level.

Allocation is likely to be politically fraught not only because so many interests have a stake in the outcome but because the sum value of assets involved is also large. Modeling analyses of the program design first outlined by the Commission in its 2004 report suggest that the total value of emissions allowances during the first phase of program implementation is on the order of $30–$40 billion each year; over a 10-year period, the sum value of allowances would be in the hundreds of billions of dollars. Under a program design with more stringent emissions targets and/or higher price caps, the cumulative value of allowances would be even higher. Importantly, however, the sum value of allowances does *not* equal the cost of the trading program to society, which, in the case of the NCEP proposal, is much less—about $4 billion per year.

> *"Clearly, requiring emitters to submit allowances and then limiting the pool of available allowances has the effect of attaching value to every ton of emissions avoided."*

The crucial distinction between allowance costs—which largely represent a transfer of wealth between holders and buyers of allowances—and societal program costs, which are the costs incurred to achieve actual emissions reductions, is discussed in the next section. That discussion also helps to elucidate why the sum value of allowances in any program designed to achieve relatively modest reductions will far exceed the total societal cost incurred to achieve those reductions.

B. THE DIFFERENCE BETWEEN ALLOCATIONS COSTS AND PROGRAM COSTS

One of the most important misperceptions that arises in many allocation discussions is the assumption that allowance values correspond to program costs. Clearly, requiring emitters to submit allowances and then limiting the pool of available allowances has the effect of attaching value to every ton of emissions avoided. And at first glance, the requirement to submit an allowance for each ton of emissions might seem to constitute a pure cost. But that is a private cost to the emitter and, because it generates an equal source of income for the allowance seller, not a cost to society as a whole.

A Short Lexicon of Key Terms

Allowance or **permit:** A kind of currency that entitles the holder to emit a defined quantity of the substance being regulated. Allowances or permits are typically valid for a specified year, but many program designs allow them to be saved or "banked" for future years. Each allowance or permit has the same market value, which is determined by the marginal cost of achieving the next ton of emissions reduction.

Allocation: The method used to distribute allowances. Often also used to mean the share of allowances that is awarded for free to particular firms or sectors.

Auction: A mechanism for distributing allowances (or permits) in which entities bid to purchase allowances. The government can auction allowances instead of giving them away for free, thereby generating revenues for the public treasury. Other entities that are not directly regulated under the program but that receive an allocation of free allowances on behalf of consumers or for other purposes can also use an auction mechanism to convert those allowances to cash.

Free Allocation: A method of allocation in which government gives allowances or permits for free to affected entities. The use of historic data (e.g. past output, emissions, or fuel-input) to distribute free allowances to existing entities is often called "grandfathering."

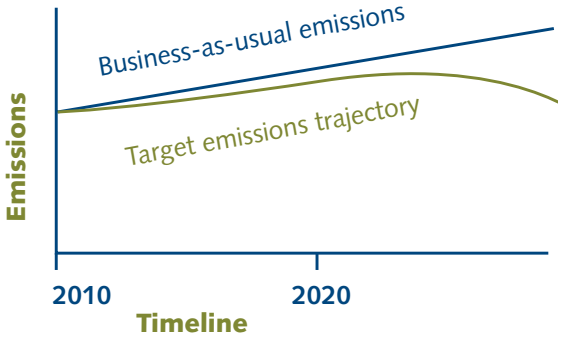
Point of Regulation: Where in the chain of energy production, distribution, and end use the requirement to submit allowances or permits is imposed.

Cost: Means different things in different contexts. Cost to society equals actual cost of mitigation efforts undertaken in response to the policy. Cost to individual firms or industry sectors equals program or compliance costs—including the cost of mitigation efforts, as well as purchased allowances or higher energy costs—that cannot be recovered from customers. From a societal point of view, expenditures to purchase allowances or to cover higher energy prices represent a *transfer* of wealth to the original allowance holder or upstream energy provider, not an actual cost to society.

Opportunity Cost: Revenues foregone as a result of using an allowance or permit that could otherwise be sold to someone else.

Safety Valve: A government-established limit on the maximum market price of allowances or permits (typically achieved by making an unlimited number of additional allowances available from the government at a fixed price). Used in some recent proposals to cap the overall economic costs of a trading program.

Figure 1. Allowances Available for Allocation in Relation to Emissions Mitigation



This is not hard to see in the case where government distributes allowances for free at the outset. Suppose the distribution is such that all firms find it efficient to set emissions equal to the allowances they have been issued. In this case, allowances are not bought or sold and the only cost to firms is what they spend to reduce emissions to a level equal to the allowances they receive. Allowances still have value, of course, and firms must surrender these valuable assets when they emit, but these submissions involve no cash cost: firms are simply handing back to the government assets that the government gave out in the first place. The same conclusion holds for firms in aggregate whenever allowances are distributed for free: even if those allowances are subsequently bought and sold, buyers' outlays become sellers' receipts. In short, when allowances are distributed for free, firms in aggregate are given a new asset that is equal (but for transaction costs, if any) to their new obligation to submit an allowance for each ton of emissions. As before, the only net cost imposed on these firms as a group is the cost of reducing aggregate emissions to the target level of the policy.

It is also the case that the cost of allowances is not a cost to society as a whole, however, when the government chooses to auction all allowances instead of giving them away for free. In that instance, resulting revenues are returned to the federal Treasury and become available to reduce the deficit, offset other taxes, or fund additional public spending. (This is similar to the familiar point that the cost to society of a tax is not measured by the revenues it yields the government but by the distortions it imposes on the economy.) Either way, allowance transactions represent a transfer of wealth from the allowance buyer to the allowance seller, but do not equal a net cost to society.

Limiting emissions does impose a real cost on society, of course, but that cost is equal to the cost of actual mitigation measures undertaken as a result of the policy and is generally far smaller than the face value of allowances. In the case of the Commission's original proposal, actual emissions-mitigation costs are estimated to average roughly $4 billion per year over the first ten-year implementation period, or roughly one-tenth of the estimated $30-40 billion allowance value associated with the trading program.

Given that mitigation costs, at the margin, determine the price (or value) of each allowance, the mismatch between aggregate allowance value and aggregate mitigation costs might seem counter-intuitive. In fact, however, this mismatch is a simple function of the fact that the number of tons being reduced under the policy is much smaller than the number of tons that continue to be emitted (and for which allowances are issued). Figure 1 helps to illustrate this point in very general terms: the area between the business-as-usual emissions trajectory and

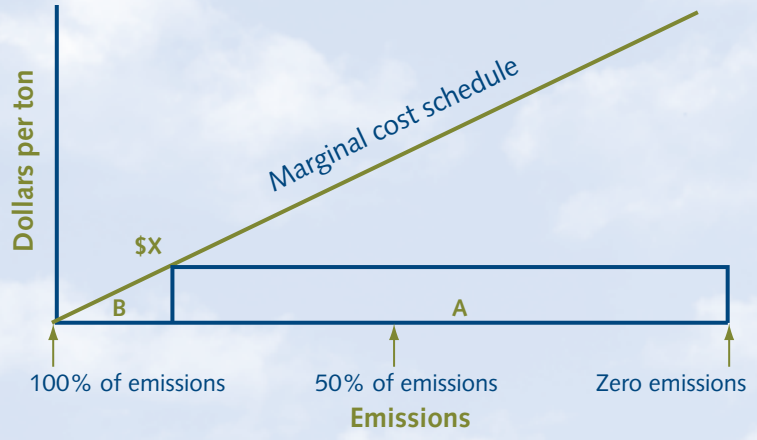
> *"It must be emphasized that the actual cost of the NCEP proposal to the U.S. economy is very small."*

the target emissions trajectory is much smaller—especially in the early years of program implementation—than the area below the target emissions trajectory. The original Commission proposal, for example, is designed to generate a $7-per-ton incentive on roughly 6 billion tons of carbon in order to stimulate roughly 200 million tons of reductions (at a per-ton cost at or below $7) in its first year. As a result, the value of allowed emissions—which is also the value of the allowance market—is roughly $42 billion ($7/ton x 6 billion tons). Meanwhile, since many of the reductions taken as a result of the policy cost less than $7 per ton, aggregate mitigation costs are well below $1.4 billion ($7/ton x 200

"…firms will be equally motivated to reduce emissions because foregoing the opportunity to sell a free allowance creates exactly the same economic incentives as being required to buy an allowance one doesn't have."

Allowance Value and Mitigation Cost

The graph below serves to illustrate why there is likely to be a large discrepancy between cumulative allowance value and actual mitigation cost in the early years of any program to reduce CO2 emissions. In the graph, the market price of an allowance, based on the marginal cost of reductions at the emissions target, is $X per ton.* The total face value of available allowances equals the area of rectangle A (that is, remaining emissions multiplied by $X/ton). Total mitigation cost, is equal to the area of triangle B because it includes all reductions available further down the marginal cost curve (that is, for a per-ton cost less than $X). In fact, regardless of the allowance price $X,** the sum value of allowances available for allocation will always be greater than the costs incurred for mitigation *as long as the number of tons still being emitted is greater than the number of tons being reduced (i.e., target emissions reduction is less than 50 percent).*



* *In reality, the marginal cost schedule is likely to follow a curve, but for purposes of this explanation costs are assumed to rise in a linear fashion. Note also that in a program design like that proposed by NCEP, the final allowance price $X is limited by the safety valve mechanism rather than by a given emissions target.*

** *Except in the extreme case where program targets are so weak that, in effect, no reductions are required. In that case, allowance supply exceeds demand and (provided companies do not engage in hoarding behavior) allowances have zero market value. Of course, in that case mitigation costs incurred are also zero.*

million tons). A more general, theoretical discussion of this point is provided in the text box at left.

It must be emphasized that the actual cost of the NCEP proposal to the U.S. economy is very small. In fact, the U.S. Energy Information Administration (EIA), in a comparative analysis of several legislative proposals, one of which closely followed the NCEP recommendations, found that such a program would have "no meaningful impact" on the nation's future economic growth. EIA reached that conclusion on the basis of modeling estimates indicating that the total impact of the program would be on the order of a few tenths of a percent of GDP, compared to projected GDP growth on the order of 60 percent, over the next 15 years (EIA, 2005). This finding is not surprising, given that the actual emissions reductions achieved by the policy (relative to a business-as-usual trajectory) are also small over the same time period. As discussed at length in its 2004 report, the Commission deliberately designed an approach that was initially modest and protective of existing investments in long-lived capital assets to overcome the cost and competitiveness objections that have so far stymied efforts to reach consensus on a mandatory national climate policy. Accordingly, it recommended a policy framework designed first to slow emissions growth—undertaking more substantial reductions only later if called for—and to limit overall costs to the economy.

C. HOW ALLOCATION AFFECTS EQUITY AND INCENTIVES

Any regulatory system, however modest or aggressive, will create winners and losers. One of the significant advantages of an emissions-trading program is that it separates distributional issues from efficiency issues. Efficiency requires that all emitters face the same price per carbon-equivalent ton of emissions **at the margin**. This creates an equal incentive to reduce emissions across all affected sectors and leads to cost-effective system-wide reductions. Permits or allowances can be allocated any number of ways, but as long as each ton of emissions must be covered by an allowance, emitters will have an incentive to implement all reductions available at a per-ton cost below the allowance price. If a firm receives an allocation

"Free allowances are most appropriately viewed as the equivalent of an up-front, lump-sum payment: in effect, handing out free allowances is the same as handing out money."

less than its total emissions, it can either reduce its emissions or pay the market price for the additional allowances it needs. But even a firm that receives a quantity of free allowances in excess of its total emissions can—by reducing emissions—increase the number of unused permits it has available to sell at the market price.

In other words, both firms will be equally motivated to reduce emissions because foregoing the opportunity to sell a free allowance creates exactly the same economic incentives as being required to buy an allowance one doesn't have. The magnitude of that incentive is the same for all firms and is entirely driven by the price of allowances, which in turn is a function of the overall stringency of the program relative to the cost of available emission-reduction opportunities throughout the economy.

In sum, allocation decisions should have no impact on incentives, on the amount of emissions reductions achieved as a result of the policy, on where emissions reductions occur, or on who bears the cost of implementing them.[4] (A more complete explanation for this somewhat counterintuitive finding is provided in Section IV of this report, which describes how the costs of regulation are passed through the energy supply chain.)

Rather, free allowances are most appropriately viewed as the equivalent of an up-front, lump-sum payment: in effect, handing out free allowances is the same as handing out money. Exactly how that's done obviously matters a great deal to individual firms and to other potential recipients, even if it doesn't change underlying costs or aggregate program outcomes. For policy-makers, however, the relevant point is that allocation offers an opportunity to offset some of the economic burden of regulation for different stakeholders—and in particular to partly compensate those who bear a disproportionate share of that burden.

The Relationship Between Allocation and Incentives

Consider two profit-maximizing firms, Firm A and Firm B. Both emit 100 tons of CO_2. The market price of CO_2 allowances is $7/ton. Both firms can avoid 20 tons of emissions at a cost of $5/ton. The remaining 80 tons would cost more than $7/ton to avoid.

Firm A receives no free allowances. Firm A will go ahead and pay $5 per ton to avoid 20 tons of emissions since each avoided ton saves $2 (the difference between the $7/ton allowance price and $5/ton reduction cost). Compared to leaving its emissions unchanged, Firm A saves $40. To buy the remaining allowances it needs, Firm A spends $560 (80 tons x $7/ton) to buy allowances, so its total (private) cost is $660.

Firm B receives 100 free allowances. Firm B is also motivated to avoid 20 tons at a cost of $5/ton because it can sell any allowances it doesn't use for $7/ton. Each allowance sold nets Firm B $2/ton—again for a total gain of $40 compared to leaving its emissions unchanged. Firm B uses its remaining allowances to cover its remaining emissions and by doing so foregoes the $560 it could have gained by selling those allowances in the market place. Firm B's total (private) cost is $100 to reduce emissions minus $140 from the sale of allowances, for a net (private) gain of $40.

Both firms reduce emissions by exactly the same amount (20 tons) and both gain exactly $40 by doing so (compared to not reducing emissions). Obviously, Firm B is much better off for having received free allowances. (The difference between Firm A's cost and Firm B's gain is $700, exactly the market value of B's free allocation.) But the incentive to avoid emissions is driven by the $7/ton price of allowances and is the same for both firms.

[4] Important caveats to this general rule may apply in the case of allocations to regulated utilities and in other situations where market prices are not determined by competition. See further discussion in Section IV and in text box on page 18.

III. Options for Allocation

Emissions permits or allowances can be allocated through a variety of mechanisms. In the federal Acid Rain Program, almost all SO_2 allowances were allocated at no charge to emitters—in this instance primarily regulated, investor-owned or public utilities—mainly on the basis of historic data. A small pool of allowances, 2.8 percent of the total, was set aside to be auctioned annually by the U.S. Environmental Protection Agency.[5] The SO_2 auction is non-revenue-raising, however, in the sense that proceeds are returned to the entities from which auctioned allowances were withheld in the original allocation. In large part, the auction was created to assure potential buyers—including new market entrants—that they would be able to obtain allowances, and to aid in price discovery. That is, the auction assured market participants that there would be allowances for sale and that prices would not be artificially inflated if firms with excess allowances were initially reluctant to sell for some reason. Though such artificial shortages have occurred in the European Union trading program (discussed in later sections), SO_2 allowance markets in the United States have proven to be fairly liquid and new entrants have not had difficulty obtaining allowances.

Although a similar mechanism could be used to allocate allowances under a greenhouse gas program, equity considerations are likely to argue for a different approach. For reasons that are explored in detail in later sections, awarding most allowances for free to entities that are directly regulated under the program will produce large windfall profits for those entities at the expense of consumers and other energy end-users. When the Acid Rain Program was adopted there were widespread worries about the workability of what was then an extremely novel and untested form of environmental regulation. At a time when SO_2 emitters feared substantial cost increases, mention of possible windfall profits would have been met with incredulity, if not laughter.

In any case, the equity implications of allocating primarily to emitters in the SO_2 context were not as troubling as they would be in the context of an economy-wide greenhouse gas program. First, the sum value of allowances under the Acid Rain Program was much smaller: on the order of $1-$2 billion per year compared to a combined allowance value on the order of tens of billions of dollars per

[5] The auction itself is conducted by the Chicago Board of Trade.

year under a greenhouse-gas trading program such as the Commission has proposed. As a result, the potential for windfall profits and for large wealth transfers from electricity consumers to producers was also smaller. In addition, the electric power sector was subject to comprehensive regulation at the time the Acid Rain Program was adopted, which meant that economic regulators could—at least in theory—exercise some control over the ultimate distribution of allowance value among industry participants and other stakeholders.

The fact that an economy-wide greenhouse-gas trading program involves much larger allowance assets and would reach beyond the electric power sector further complicates its distributional impacts and bolsters the rationale for departing from past approaches, which have tended to favor a mostly free allocation to those industries most directly affected by regulation. The primary alternative to a free allocation is an auction, in which government simply sells available allowances or permits to the highest bidder.[6] This approach has several important advantages. First, it avoids the need for government to develop and implement a methodology for allocating to individual firms. Second, it ensures that allowances or permits are available for trade and gives all participants equal access to them, putting new entrants on the same footing as existing emitters. Third, and most important, an auction can generate significant revenues that can then be directed to other public purposes: to reduce other taxes; cut the deficit; fund R&D programs; and/or compensate industries, workers, and consumers who bear a disproportionate share of regulatory costs.

> *"The specific benefits of an auction approach, and how those benefits are distributed throughout society, depend on how auction revenues are used."*

The latter point is the strongest argument for an auction approach and bears emphasizing. Indeed, the economics literature consistently favors auctioning emission allowances and using the resulting revenues to reduce other distortionary taxes because this significantly reduces net social costs compared to giving allowances away for free. In general, economic theory favors shifting from taxes on desirable activities or things (like income, savings, or investment) to taxes on undesirables (like pollution or energy consumption). In effect, implementing a greenhouse-gas trading program, auctioning emissions allowances, and recycling the revenues to provide tax relief could accomplish just such a shift. By contrast, any methodology that gives allowances away "for free" is more costly because it forgoes the opportunity to put auction revenues to more productive uses. One paper finds, for example, that the benefits—in terms of improving overall economic efficiency—of using auction revenues to reduce personal income taxes would offset the actual costs society incurs to reduce emissions under a greenhouse-gas trading program by as much as 50 percent (NCEP, 2004).

As discussed later in this section, most current proposals for regulating greenhouse gas emissions through a trading program combine some elements of auction and free allocation. The next section reviews the characteristics of each approach, along with the merits of a mixed approach.

A. AUCTION VS. FREE ALLOCATION

As noted above there is strong agreement in the economics literature that auctioning allowances and using the proceeds to reduce other taxes is strongly preferable to a free allocation. The specific benefits of an auction approach, and how those benefits are distributed throughout society, depend on how auction revenues are used. If auction revenues are

[6] The term "auction" has been used in some contexts to describe a situation where the government allocates free allowances to a non-emitting entity (such as a consumer organization or distribution utility) with the understanding—or the requirement—that proceeds generated by auctioning those allowances will be used for a specific purpose (such as for low-income or energy-efficiency programs). In this way, revenues can be directed to various programs or organizations without the government being in the position of first collecting and then re-distributing those revenues.

used to reduce payroll taxes or are rebated directly to households in the form of lump-sum payments, they can help offset the regressive impacts of energy-price increases resulting from emissions constraints.[7] If, on the other hand, auction revenues are used to reduce taxes on capital gains or corporations, total societal costs are still lower, but the benefits flow primarily to wealthier households.[8] Finally, if auction revenues are instead used to support new government spending for other purposes, the social-welfare impacts depend on the merits and efficiency of that spending.

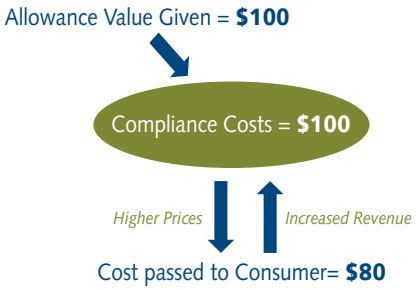
> *"Many firms—if they receive free allowances in proportion to their emissions—will not only be effectively compensated for their costs, but can expect to realize substantial profits."*

While an auction approach has the potential to provide the largest net social benefits, those benefits are, by nature, diffuse. Cost impacts under an auction approach, on the other hand, tend to be concentrated in those industries that are most strongly affected by the emissions control program. This produces a political dynamic that generally favors free allocations over auctioning approaches. There is no reason in principle, of course, that auction revenues could not be used to offset costs for disproportionately affected interests. But the industries most directly affected by regulation typically exert strong pressure to be compensated in the form of free allowances instead, based on the (probably correct) assumption that they are likely to fare much better competing for allowances versus competing for federal dollars. First, a transfer of free allowances is likely to be more politically secure than government promises of compensation from auction revenues. More importantly, many firms—if they receive free allowances in proportion to their emissions—will not only be effectively compensated for their costs, but can expect to realize substantial profits.

This crucial point has until recently not been well understood by policy-makers, regulators, and the public. It becomes more obvious when one looks closely at how costs are imposed under a market-based trading program and how the market and individual companies respond—a topic taken up later in this White Paper. In simple terms, however, the argument goes as follows: under a greenhouse-gas trading program, the market price of goods and services throughout the economy will rise to reflect the value being placed on carbon emissions. That is because, for every ton of emissions released, some entity somewhere in the energy chain[9] will have to submit an allowance that has real monetary value. That monetary value (or price) is set by the market in response to the marginal—or most expensive—ton of reductions being implemented as a result of the policy. All energy producers—*whether they received free allowances or not*—will receive additional revenues as a result of higher prices. If the same companies

Figure 2. Free Allowances as a Source of Profit

Firm A needs $100 in allowances to cover emissions. Higher prices allow Firm A to pass $80 of this cost on to consumers, so actual losses under the program total $20. If Firm A gets $100 worth of free allowances, it will realize $80 in profits.



[7] As has already been noted, energy prices will increase to reflect the carbon price signal created by the trading system even if all allowances are given away for free. Economists generally do not favor these kinds of giveaways because they too forego the efficiency-enhancing benefits of using auction revenues to reduce distortionary taxes. From a political standpoint and as a means of addressing regressivity concerns, however, the lump-sum payment approach could have distinct advantages.

[8] Auction revenue could also be used to meet other federal budget priorities (for example, addressing unfunded liabilities related to the retirement of the baby boom generation). Implicit in this, however, is that revenue is being used to avoid a tax increase; in this way, it is the same as the preceding cases.

[9] Which specific entities are required to submit allowances depends on where the regulatory obligation is imposed. Point-of-regulation is a separate but also important issue and is discussed in a later section of this White Paper.

also receive large, up-front payments in the form of free allowances, those payments can easily exceed any net costs that companies experience as a result of implementing emissions reductions and charging higher prices. *In other words, firms that receive free allowances and experience increased revenues from higher prices get reimbursed twice—once by government and once by the consumer.* This point is illustrated by Figure 2 and by a hypothetical example in the text box to the right.

As one analyst puts it "because allowances are worth money, distributing them *gratis* amounts to the government distributing money to private interests, but without a transparent cash transfer" (Climate Policy Center, 2003).[10] When scaled to a carbon-dioxide allowance price of $20 per ton, modeling results summarized in Goulder (2003) indicate that coal-industry profits could quadruple if allowances under a greenhouse-gas trading program are grandfathered to coal producers based on coal's share of aggregate emissions, even if as in this example, coal production would be expected to fall by 10–15 percent.[11] Recent experience with the Emission Trading System (ETS) now being implemented by the European Union (EU) suggests that the potential for windfall profits, far from being purely hypothetical, is borne out by empirical evidence, with utility companies that received free allocations under the EU program having realized substantial gains (see further discussion at Section III.C). Given that both energy producers and the general public bear some burden under a greenhouse-gas trading program, an allocation approach that auctions all allowances and recycles the proceeds in the form of tax relief will have the overall effect of transferring some wealth from energy producers to the broader public (in this case taxpayers). Conversely, an allocation approach that gives all allowances for free to directly affected industries will have the overall effect of transferring some wealth from the broad public (in this case consumers) to those industries.

An allocation that does a little of both, on the other hand, could end up leaving both groups roughly equally well off. In other words, compared to either a pure auction or pure grandfathering, a mixed strategy—in which some allowances are auctioned and others are given away for free—may create opportunities to realize broader public benefits while also addressing legitimate industry concerns about

Costs, Allocation, and Windfall Profits

Consider a refinery that produces 1000 gallons of gasoline. Based on the carbon content of its gasoline, it must submit one CO_2 allowance for every 100 gallons of gasoline it produces. Each CO_2 allowance costs $7. Thus, the requirement to submit allowances effectively increases the production cost of every gallon by 7 cents. This is true even if the refinery receives free allowances: in that case using an allowance is like dipping into company savings—it means taking something of value out of the company's pockets and foregoing the opportunity to convert it into cash by selling it.

The effect of the allowance requirement is therefore exactly analogous to the effect of any other increase in production costs. In the case of a refinery, it is similar to a 7 cent per gallon increase in the cost of crude oil inputs. Experience indicates that refineries can and will usually pass such cost increases directly through in the price of finished products. Assuming all refiners (and importers of refined products) are subject to the same policy, gasoline prices will rise by 7 cents per gallon to reflect the opportunity cost of using allowances.

When gasoline prices rise, refineries can expect to sell less product and—if the demand reduction is sufficiently large—may experience lower profits. In fact, any demand reduction caused by a 7 cent-per-gallon price increase would likely be minimal. But for illustrative purposes, assume the refinery's sales decline by 50 gallons and assume that this causes a $10 loss in profits.

If the refinery starts with no free allowances it will charge the market price (now 7 cents per gallon higher to reflect allowance costs). The added per-gallon revenue (7 cents) will be just enough to buy the allowances it needs to cover its compliance obligations (7 cents per gallon times 950 rather than 1000 gallons of sales, or $66.50). Its net profit loss is thus $10.

Instead, suppose the refinery receives 10 free allowances at the outset—exactly enough to cover its compliance obligations based on its historic output of 1000 gallons. Prices still rise by 7 cents per gallon, the refinery still experiences a 50 gallon reduction in sales, and it still loses $10 in profits on those 50 gallons as a result. And the refinery again collects $66.50 in extra revenue and (because of the 50 gallons it didn't sell) has the equivalent of one-half an allowance (worth $3.50) available to sell. In other words, the refinery gains $70—exactly the market value of its initial allocation—minus the $10 in losses it experiences because of lower sales. It thus realizes a net gain (or windfall profit) of $60.

[10] Goulder (2003) notes that "By introducing a permits program, the government in effect encourages producers to behave like a cartel in restricting their output. Under a system of auctioned permits what would be cartel profits or rents are collected by the government. In contrast, under a system of freely allocated permits, these rents are retained by producers. Thus freely allocating 100% of the permits causes profits to rise in the fossil fuel industries."

[11] The finding that fossil-fuel industry profits actually increase under an emissions trading program with grandfathering raises an obvious question: why have most industry actors nevertheless been strongly opposed to such programs in the past, even with free allocation? Lane (2003) offers a number of possible explanations, including the *ex ante* uncertainty for individual firms in terms of how their specific competitive position will be affected; fear that more stringent control requirements will follow in time; opposition to emission controls in principle, etc.

cost impacts. Moreover, a phased approach, wherein a substantial portion of allowances is grandfathered in the early years of program implementation but that share gradually diminishes in subsequent years to allow for a larger auction, may offer particular advantages in terms of creating a transition period for energy-intensive industries (especially those with a long-lived capital assets), while eventually securing the social welfare and efficiency-maximizing benefits of an auction.[12] Recent U.S. proposals to implement cap-and-trade-style programs for greenhouse gas emissions, including the Udall-Petri bill noted in the Introduction and the Regional Greenhouse Gas Initiative discussed in later sections, have increasingly featured a mixed approach where some share of allowances is still grandfathered, but a significantly larger share of allowances than in past programs is auctioned or otherwise set aside for public purposes.

B. USE OF ALLOCATION TO ADVANCE OTHER POLICY OBJECTIVES

Although free allowances have generally been awarded to directly affected industries in past emissions trading programs, allowances can also be allocated directly to other stakeholders or to promote specific activities or investments. In the U.S. Acid Rain program, for example, a small portion of allowances was set aside to reward energy-efficiency and renewable-energy programs that reduced SO_2 emissions. Various proposals for a national-level greenhouse-gas trading program have contemplated using a portion of the available allowance pool to promote energy technology research and development, support agricultural and other carbon offsets (including carbon capture and sequestration projects), support energy-efficiency programs, provide credit for early reductions, support technology transfer and other initiatives in developing countries, help consumers and low-income households, and provide transition assistance to workers in affected industries.

As a practical matter, allocating to groups or individuals (such as consumers) who are not likely to participate directly in allowance markets, or to support specific activities such as technology research and development, will require some mechanism to convert allowances into disbursable revenues. Such a mechanism might function very much like—or in fact be equivalent to—an auction. The Climate Stewardship Act, introduced by Senators John McCain and Joseph Lieberman in 2003, proposed to create a non-profit corporation for the purpose of selling permits and refunding the proceeds to consumers, although the bill did not specify the amount to be auctioned.

"If cost equity is a primary consideration, a strong rationale exists for allocating allowances to (or on behalf of) energy end-users (including both energy-intensive businesses and households) and not just to directly regulated entities."

If cost equity is a primary consideration, a strong rationale exists for allocating allowances to (or on behalf of) energy end-users (including both energy-intensive businesses and households) and not just to directly regulated entities. As discussed extensively in Section IV of this White Paper, the net social costs imposed by a trading program are generally unaffected by where in the energy-supply chain the compliance obligation is imposed. Available analyses indicate that much of the cost of using emissions allowances—including both costs incurred to purchase allowances and the opportunity cost of using (rather than selling) allowances that were received for free—will be passed to consumers and other energy end-users, no matter which entities are actually required to submit allowances. In fact, modeling results indicate that roughly one-third of the total market value of allowances will be passed directly through to households in the form of higher energy prices. Moreover, households are likely to bear additional, indirect costs as businesses attempt to pass at least some of their added energy costs through in the form of higher prices for energy-intensive goods and services.

Different but also compelling arguments may justify the use of some portion of available allow-

[12] In its 2004 report, the Commission proposed that 5 percent of available allowances be auctioned initially, with the auction expanding gradually thereafter to a maximum of 10 percent of allowances. As discussed in later sections, the Commission's views on the latter point have evolved; NCEP now supports the concept of a gradual transition to a much larger auction.

ances to support technology development and other activities. As the Commission emphasized in its 2004 report, the near-term price signal generated by any politically viable greenhouse-gas trading program is likely to be relatively small and will probably be inadequate, by itself, to promote the widespread adoption of new technologies, let alone stimulate the research and development investments required to achieve fundamental advances in energy use and production. Generally, innovative firms are unable to appropriate the full gains associated with their efforts, leading to an inadequate incentive to develop new technologies.

Similarly, the trading program by itself may not provide sufficient incentives for certain types of emissions-reduction or adaptation measures (such as geological or terrestrial carbon sequestration) that would be worthwhile from a societal point of view, particularly where such opportunities exist in sectors like forestry and agriculture that are not directly covered by the trading program.

> *"Future allocation debates in the United States are likely to be influenced by the experience of other countries that are implementing market-based greenhouse-gas reduction programs."*

A report recently released by the Congressional Budget Office (CBO) finds that a combination of market signals and R&D investments is likely to be the most cost-effective long-term strategy for achieving carbon-dioxide reductions (CBO, 2006). Auctioning some share of allowances and using resulting revenues to support technology initiatives would produce exactly the combination of market pull and market push recommended in the CBO report. In sum, allocation methodologies that promote a wider array of emissions-reduction options for the future could provide a cost-effective and ultimately efficiency-enhancing way to advance national climate-policy objectives and reduce the costs associated with meeting potentially more stringent carbon reduction targets in the future.

C. ALLOCATION IN EXISTING PROGRAMS AND RECENT PROPOSALS

As noted in the foregoing discussion, the presumption that most allowances should be allocated for free to those entities that are directly regulated under a trading program appears to be changing. The joint statement issued by Senators Domenici and Bingaman in June 2006 concerning emerging themes for the design of a future climate policy reflects this shift, as do several other recent greenhouse-gas trading proposals that have already been mentioned. Indeed, even earlier evidence for a changing view of allocation can be found in the Bush Administration's original Clear Skies proposal for reducing national power sector emissions of conventional air pollutants. That proposal called for a gradual transition, over a period of roughly 50 years, from a 100 percent grandfathered allocation to a 100 percent auction.

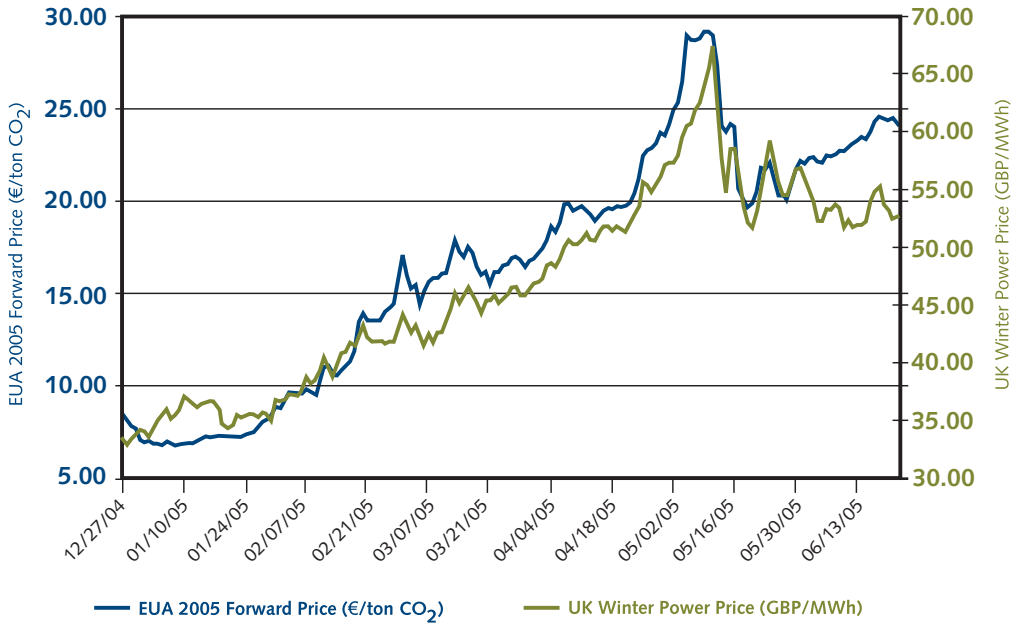
Future allocation debates in the United States are likely to be influenced by the experience of other countries that are implementing market-based greenhouse-gas reduction programs. Of particular interest in this regard is the EU ETS, which affects nearly 12,000 installations in five major industrial sectors. Under the EU program, each member state develops its own National Allocation Plan (NAP) subject to guidelines established by the European Commission. The guidelines require at least 95 percent of all permits to be allocated to industry for the first compliance period (2005–07), with a maximum of 5 percent of the total pool held back for public auction. For this phase, most EU members chose to allocate all available permits for free to affected industries, although a few countries included a small auction.[13] For the second compliance period (2008–12), EU guidelines call for each member to allocate at least 90 percent of its permit allocation for free, leaving up to 10 percent of permits available for auction. Of the 19 EU member states that have publicly announced their Phase II allocation plans, eight are currently proposing to auction some allowances (they include the Flan-

[13] Specifically, Denmark auctioned 5 percent of permits, Hungary auctioned 2.5 percent, Lithuania auctioned 1.5 percent, and Ireland planned a small auction of 0.75 percent of available permits to raise revenues to administer the trading program.

The European Experience with Allocation

The EU ETS offers an unprecedented opportunity to observe the real-world political and economic dynamics of allowance allocation under a broad-based greenhouse-gas trading program. As noted in the main text, most EU member states have allocated all or nearly all allowances for free to regulated entities. This practice has become increasingly controversial, however, as evidence has emerged that electric-power producers realized windfall profits as a result of free allocations, while still—as the figure below indicates and as economic theory would predict—passing the opportunity costs of using allowances on to consumers in the form of higher electricity prices. A report commissioned by the Dutch government found that a significant percentage of the value of allowances allocated to the power sector was passed through in the price of electricity, with the result that some companies' profits increased substantially. The authors of the study suggested that auctioning a larger share of allowances could address these distributional issues. A study for the U.K. government reached similar conclusions, finding that the overall profitability of U.K. power producers grew by approximately £800 million over the first phase of the ETS.

UK power prices and EU allowance prices have shown a strong correlation.



Data provided by Barbara Buchner, Fondazione Eni Enrico Mattei (FEEM)

The behavior of EU stock markets provides additional evidence for the link between free allocations and power-company profits. When allowance prices in the ETS plunged suddenly at the end of April 2006, stock prices for some of the largest power companies in Europe also fell. Intuitively, a lower allowance price should signal lower mitigation costs and lower profit losses. But in a world where opportunity costs are passed through and companies receive free allowances, a lower allowance price means *reduced* profits.

Some EU member states have begun to address the windfall issue as they release their proposed NAPs for Phase II of the ETS. For example, the UK has proposed auctioning 7 percent of its total allocation, with the additional portion auctioned being taken out of the allocation for the electric power sector. The Netherlands has proposed to reduce allowance allocation to the electric power sector by 15 percent. Two-thirds of these allowances would instead be auctioned, with the proceeds going to low-volume electricity consumers. The remaining third would be allocated to industrial participants in the EU ETS. Meanwhile, as noted in the main text, the German government's Cartel Office recently concluded that utilities should be allowed to pass at most 25 percent of the opportunity cost of using free allowances along in the price of electricity.

> *"Firms would be required to demonstrate that they qualify for these allowances based on several criteria, including expected higher costs as a result of the carbon cap, high energy-intensity, and significant international competition for their products."*

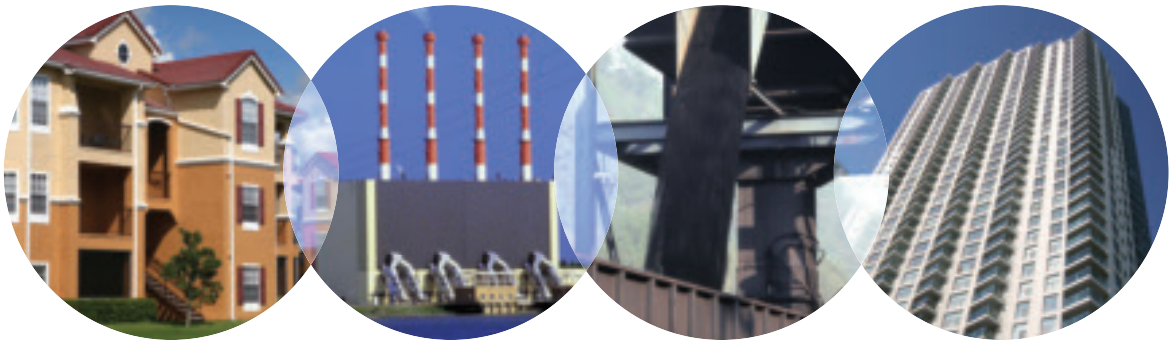
ders region of Belgium, Ireland, Italy, Lithuania, Luxembourg, the Netherlands, Poland, and the United Kingdom). So far, the UK has proposed the largest auction (7 percent of allowances). Germany has already indicated its intent to allocate 100 percent of permits at no cost to emitters in the second period as well, but its Cartel Office recently announced that utilities could pass at most 25 percent of the opportunity cost of using free allowances through to consumers (see further discussion in text box on page 14).

Two other recent initiatives—a regional carbon cap-and-trade program within the United States and a similar proposal in Australia—depart more dramatically from the traditional model of (mostly) free allocation. The Regional Greenhouse Gas Initiative (RGGI) is an effort by seven northeastern and mid-Atlantic states to cap regional power-sector carbon emissions.[14] The program is scheduled to go into effect in 2009. Initially, power-sector emissions will be capped at approximately current levels; starting in 2015, the cap begins to decline with the aim of reducing emissions to 10 percent below current levels by 2020. A Memorandum of Understanding (MOU) signed by RGGI participants gives each state broad discretion over how its allowances will be distributed; however it also requires each state to allocate 25 percent of its allowances to a public benefit fund that will be used to mitigate impacts on electricity consumers or to promote low- or no-carbon technologies. States may opt for an even larger public benefit pool; New York, for example, recently proposed to auction 100 percent of its state-wide allowance allocation under the program. Several RGGI states have already indicated that funds generated by the auction—which will be carried out by an entity that receives the "consumer allocation" rather than by the state itself—will be used for demand-side programs to mitigate the impact of higher electricity prices. To implement the public benefit set aside, RGGI states are exploring the use of a joint regional auction.

Australia's states and territories are likewise considering a cooperative cap and trade program that would be similar in governing structure to RGGI. This initiative, which is currently being developed by a National Emissions Trading Task Force, would also cover the power sector. In August 2006, the Task Force released a white paper that proposed several design elements for a national trading program, including a three-part allocation scheme. The first portion of the allocation would be distributed for free to generators that are most adversely affected by the cap (i.e., coal-fired power plants) based on projections of lost operating profits. The second portion of allowances would go to trade-affected, energy-intensive industries. Firms would be required to demonstrate that they qualify for these allowances based on several criteria, including expected higher costs as a result of the carbon cap, high energy-intensity, and significant international competition for their products. The paper gives several examples of industrial sectors that would be expected to qualify including steel, aluminum and other non-ferrous metals, newsprint manufacturing, and some activities in the chemicals and plastics industries. The third portion of the allocation would be auctioned with revenues administered by each state or territory to address impacts on households, regions, and small businesses.

[14] The seven states are Maine, Vermont, New Hampshire, Connecticut, New York, New Jersey, and Delaware. An eighth state, Maryland, has adopted legislation requiring the state to join RGGI by June 2007.

IV. Cost Equity as a Basis for Allocation



If allocation approaches are to be designed to promote more equitable outcomes and ameliorate disproportionate burdens on particular entities or stakeholders, it is necessary to begin by understanding how regulatory burdens under an emissions trading program are distributed throughout the economy. This section explores in some detail how firms respond to the price signals created by regulation and how, as a result, costs are transmitted through the supply chain from energy producer to end-user. A key finding—one that is somewhat counter-intuitive, but that has important implications for allocation decisions—is worth underscoring at the outset:

Even leaving aside any offsetting gains from free allocation, the costs imposed on a particular entity under a trading program are **not** a simple function of how many permits or allowances that entity requires to cover its emissions.

Rather, the burden imposed on different firms depends to a great extent on each firm's ability to pass through costs. In an upstream system where fossil fuel producers or suppliers are required to submit allowances, economic analysis and available empirical data indicate that most costs will be passed through to downstream energy users—accordingly, many of the entities that are directly regulated can expect to bear only a relatively small fraction of the program's real cost despite, in some cases, being required to submit large volumes of allowances. This point is illustrated by way of a concrete example involving a refinery in the text box on page 11. It also applies, however, to other firms in the energy supply chain.

A. DETERMINANTS OF COST INCIDENCE

Allocation decisions in past emissions trading programs, like the U.S. Acid Rain Program and the more recent EU ETS, seem to reflect a presumption that directly regulated entities—that is, those firms on which the obligation to submit permits or allowances is imposed—shoulder most of the economic burden of regulation. This presumption, while understandable when emissions trading is unfamiliar, fundamentally misunderstands the way that emissions trading programs work in practice. A corollary presumption—that giving most allowances for free to regulated entities indirectly protects consumers by making it unnecessary for those entities to raise prices—is also wrong (the latter finding is currently creating some consternation among European policy-makers, as discussed in the text box on page 14).

To understand why this is so, it is necessary to return briefly to a point raised in the first sec-

tion of this White Paper: namely, that allocation generally affects neither the price signal created by a greenhouse gas trading program nor firms' motivation to pass that price signal through to their customers. Even for a firm that receives free permits or allowances *in excess* of its compliance obligations, every permit or allowance used to cover emissions means foregoing the opportunity to sell an unused allowance in the market place. Thus using a permit or allowance is always costly, whether a firm already holds the allowance or has to go out and buy it. This is true for every firm in a market, including the marginal producer whose costs set the market price. Whether and to what extent individual firms in a given industry sector can pass the cost of using allowances to customers depends on the influence of the marginal producer on market prices (which in turn depends on competition from international suppliers and/or from less costly domestic substitutes), but *not* on the allocation.

Moreover, cost pass-through is important to the efficacy of the policy as a whole, since the key to eliciting a full range of efficient responses throughout the economy is for the carbon price signal to be transmitted all the way down the supply chain from fuel producers to end-use consumers. As a result, the (again understandable) desire by many regulators and policy-makers to minimize cost-pass-through is misplaced. Allocation and other means of recycling revenues from the trading program should be understood as a means of ameliorating disparate impacts without masking the price signals required to maximize program efficacy, not as a means of shielding consumers from the price signals needed to stimulate desired behavioral responses throughout the economy.

Ultimately, the economic burden imposed any given firm or industry sector will depend on two key determinants:

- Firms' ability to pass costs associated with fossil-fuel use backwards and forwards in the energy chain.
- Product demand reductions experienced as a result of higher prices for fossil fuels and fossil-fuel-intensive products.

How these determinants play out for broad industry sectors, let alone for individual firms, is not always obvious since a variety of factors are involved.[15] Important variables are likely to include market conditions, the regulatory environment, and the elasticity of demand for particular goods or services. A hypothetical and highly simplified example of cost pass-through, described in the text box on page 17 serves to illustrate these points.

The Dynamics of Cost Pass-Through

Suppose under a greenhouse gas trading program, coal producers must submit carbon dioxide allowances. The cost of allowances translates to $10 per ton of coal; as a result, the market price of coal rises from $20 per ton to $30 per ton.

Now consider two coal users: Manufacturer A and Manufacturer B. Each makes different products, but both use 100 tons of coal each year. As a result of the change in coal prices their coal costs initially rise by $1000 per year (from $2000 to $3000).

Confronted with higher energy prices, Manufacturer A realizes he can cut his coal use by 30 tons per year if he spends $750 on efficiency improvements. Manufacturer A makes the efficiency investment and absorbs an extra $700 in higher prices for his remaining coal consumption of 70 tons. His coal-related expenses under the trading program come to $2850 ($750 for mitigation measures plus $30 per ton on his remaining 70 tons of consumption). Compared to his previous expenses ($2000 per year at the old coal price), the incremental costs impose by the program total $850. Taking into account competition for his product, Manufacturer A can pass through $700 of these new expenses by raising prices. Thus he incurs a net loss of $150 as a result of the trading program.

Manufacturer B can reduce his coal consumption by the same amount as Manufacturer A and for the same cost. Like Manufacturer A, he makes the efficiency investment and incurs a total of $850 in incremental costs because of the program. But Manufacturer B is in a different situation than Manufacturer A: because he faces stiff competition from foreign suppliers he can pass through only $300 of his new expenses by raising prices. Thus, Manufacturer B incurs a net loss of $550—much more than Manufacturer A.

If one were trying to use allocation to compensate these firms, Manufacturer B should receive a larger share of free allowances than Manufacturer A even though their coal use at the outset and their abatement opportunities are exactly the same. (Presumably one would also seek to compensate coal producers for the profit losses they incur as a result of losing a combined total of 60 tons per year in sales to Manufacturers A and B.)

[15] The extent to which costs are passed through to consumers depends upon producers' ability to raise prices without reducing demand for the product. For a recent analysis of the distributional impacts of a tradable permits program, see Bovenberg, A Lans and Lawarence H. Goulder. "Neutralizing the Adverse Impacts of CO2 Abatement Policies: What Does It Cost?" in C. Carraro and G. Metcalf, eds., *Behavioral and Distributional Effects of Environmental Policies,* University of Chicago Press, 2001.

Before delving further into a discussion of cost and cost pass-through, however, it is worth emphasizing again the key distinction between "private costs"—that is costs imposed on individual firms or industry sectors—and societal cost. Private costs include costs to purchase allowances, to mitigate emissions, and transaction costs (if any), while societal costs are limited to costs for emissions mitigation (since opposing costs and revenues for allowance transactions and as a result of changing prices "net out" from an aggregate perspective). In an upstream system, where the obligation to submit allowances is imposed on fuel producers or suppliers, the vast majority of participants in the economy (from manufacturers to individual consumers) will experience private costs in the form of higher prices for energy and for energy-intensive goods and services. Many firms, in turn, will be able to pass those costs through as prices throughout the economy rise in response to the carbon price signal. In the end—as borne out by the modeling analyses discussed below—"the buck stops" at consumers, who ultimately shoulder most of the burden of regulation.

"Some firms or industry sectors, however, may encounter more difficulty than others in passing through costs and may bear a disproportionate burden as a result."

Some firms or industry sectors, however, may encounter more difficulty than others in passing

Allocation to the Electric Power Sector

The electric power sector accounts for nearly 40 percent of the nation's total energy-related greenhouse gas emissions; as such it has an enormous stake in the design of a national greenhouse gas trading program generally, and in allocation decisions specifically. These decisions are likely to be especially complicated in the electric-sector context, where the co-existence of largely competitive wholesale markets and various forms of cost-of-service price regulation in different parts of the country could profoundly affect the cost and equity implications of different allocation approaches.

For reasons discussed in the main text, the economic burden imposed on the electric power sector under a greenhouse-gas trading program is independent of whether the industry itself is directly regulated by that program. Whether the obligation to submit allowances falls on electricity generators, distribution companies, or upstream fuel suppliers, the price of electricity should rise to reflect the costs of allowances required to cover associated greenhouse gas emissions. Increased costs and higher electricity prices will lead to some demand reductions, but companies with a less carbon-intensive portfolio should be competitively advantaged relative to companies with a more carbon-intensive portfolio.

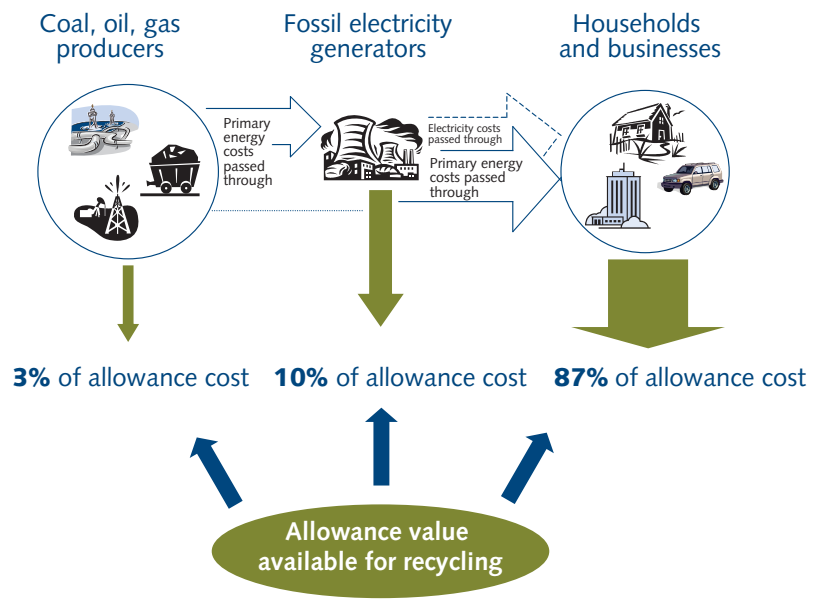
Whether individual companies and the industry as a whole experience net gains or losses depends, of course, on how emissions allowances are allocated. Here two distinct but related concerns arise. The first is that free allocations to the electric power sector in the EU ETS have produced large windfall profits for generators and resulted in very little of the allowance value being passed through to benefit consumers. This outcome, while entirely consistent with economic theory and with the achievement of the trading program's environmental objectives, is obviously troubling from an equity perspective. A second and in some ways obverse concern is that in states where electricity prices are set by regulators rather than by markets, regulators—in an effort to prevent windfall profits and shield consumers from rate impacts— could prevent utilities from passing through any opportunity costs associated with the use of grandfathered allowances. This would have two undesired effects. It would undermine program efficacy by blocking the price signal needed to stimulate efficient responses on the part of end-users. It could also create large unintended inequities between consumers in different regions, who might experience very different rate impacts depending on whether they live in traditionally regulated regions or not, and between firms in the business of supplying electricity, depending on where they operate. Moreover, since retail markets in the most coal-intensive regions tend to be regulated, the potential exists for a perverse outcome in which consumers that rely on a more carbon-intensive generation mix see a weaker price signal than consumers that rely on a lower-carbon mix.

In response to these concerns, some have proposed allocating directly to electric distribution companies (and providing explicit guidance to state regulators about the proper treatment of those allowances), rather than allocating directly to generators. In this way all electric sector allocations would come under the purview of economic regulators—state public utility commissions in the case of investor-owned utilities and local boards in the case of publicly owned utilities and cooperatives. Proponents argue that these authorities are in the best position to sort out the equity implications of different allocation schemes, direct appropriate levels of compensation to adversely affected firms, and ensure that end-use customers, who bear the largest share of program costs, receive an equitable share of the asset value associated with free allowances.

through costs and may bear a disproportionate burden as a result. Firms that compete with foreign suppliers who do not face similar emissions constraints, for example, could fall in this category. The situation may be even more complicated for utility companies that are subject to price regulation. Public utility commissions may limit these companies' ability to pass through costs, especially if the utilities receive an allocation of free or grandfathered allowances (see text box on page 18). By contrast, some sectors responsible for a large share of emissions—such as the petroleum industry—may experience only minimal profit losses because they face few constraints in passing through costs and because demand for their product is quite inelastic for the sorts of price signal generated by greenhouse-gas trading programs under discussion. Finally, some sectors—despite generating emissions and increasing product prices to cover the cost of using allowances—can experience net *gains* in profitability if regulation confers competitive advantages. In the case of the natural gas industry, for example, modeling suggests that added demand for lower-carbon fuels under a trading program would more than offset any profit losses suppliers might incur as a result of meeting their compliance obligations and charging higher prices.

Figure 3 illustrates, again in simple schematic form, how private costs (that is, the sum of mitigation costs, allowance costs, and transaction costs) are passed through the energy supply chain in a greenhouse-gas trading program. The "allowance cost" percentages shown in the figure are based on the results of a cost-incidence analysis of the original NCEP proposal that is discussed in the next section; essentially they assume that all allowances are auctioned at the outset. The chief point of the figure, however, is that (a) most private costs are passed through the energy supply chain to end-users and (b) these private costs are not net social costs: the program that creates them also creates a new asset in the form of allowance value that is available to be re-distributed to offset costs

Figure 3. Schematic of Cost Pass-Through Assuming All Allowances Are Initially Auctioned*



** Note that the percentages indicated in the figure are from an EIA analysis of cost incidence under the Commission's original program proposal. The results of that analysis are discussed in the next section of this paper.*

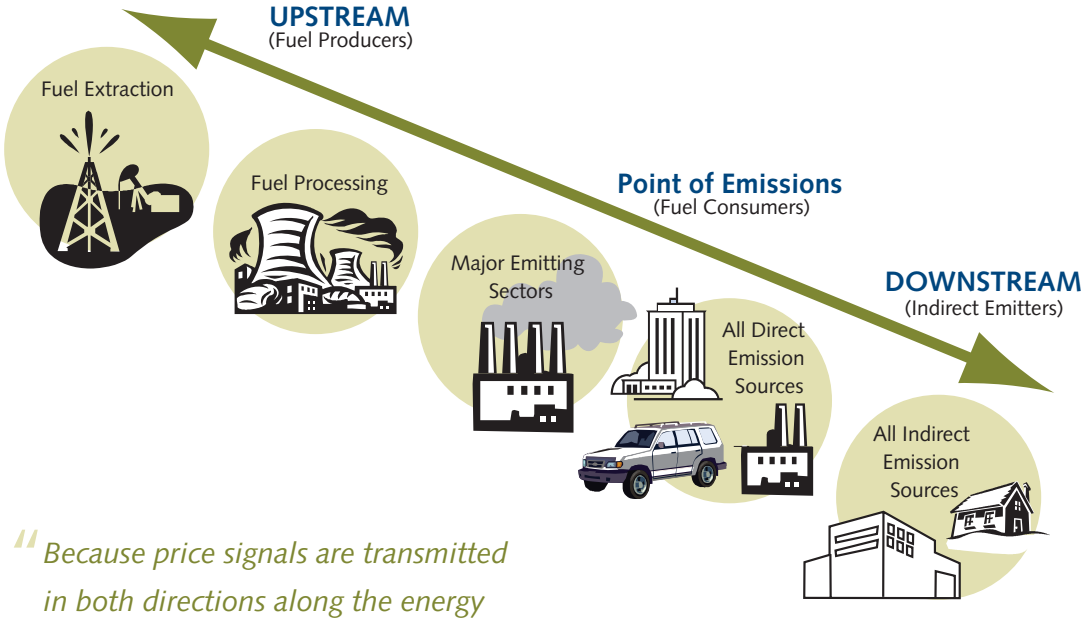
or for other purposes. In the end, of course, the *net* burden imposed on any one sector depends to a large extent on how that pool of allowance value is distributed back to various stakeholders.

B. RELATIONSHIP OF ALLOCATION TO POINT OF REGULATION

It should be evident from the foregoing discussion that if all allowances are auctioned, the distribution of burdens under a greenhouse-gas emissions trading program (leaving aside any offsetting benefit from a free allocation) is largely independent of where the obligation to submit allowances or permits is imposed.[16] Because price signals are transmitted in both directions along the energy supply chain, net costs for firms and consumers should be the same regardless of which entities in the supply chain are regulated. For example, once a market incentive exists to reduce carbon emissions, demand for coal should decline by the same amount (relative to a business-as-usual base case) regardless of

[16] It is worth noting that carbon dioxide is somewhat unique in terms of lending itself to regulation at different points in the energy supply chain. Many other types of emissions need to be regulated at the point where they are generated or released to the atmosphere because that is (a) the only place where they can accurately be measured and (b) where all the opportunities for abatement exist. Energy-related carbon dioxide emissions, by contrast, can be calculated on the basis of fuel throughput; moreover most of the opportunities for reducing emissions exist elsewhere up and down the supply chain rather than at the actual point of fuel combustion.

Figure 4. Possible Points of GHG Regulation in the Energy Supply Chain



> *"Because price signals are transmitted in both directions along the energy supply chain, net costs for firms and consumers should be the same regardless of which entities in the supply chain are regulated."*

whether coal suppliers or downstream electricity generators are required to submit allowances.[17] The net impact on the coal industry therefore depends not on whether the industry is directly regulated, but on whether it receives a free allocation of allowances—or compensation in some other form—to offset its unrecovered costs.

If cost incidence is largely unrelated to point-of-regulation, (again, leaving aside any offsetting benefit from free allocation), it follows that an allocation policy designed to address disproportionate cost impacts should also be considered independent from point-of-regulation. In other words, there is no equity basis for presuming that the entities directly regulated under the program should be entitled to a larger share of free allowances than any other entity in the energy supply chain. Decisions about point-of-regulation are, of course, extremely important from the standpoint of program design and implementation. Among other things, the choice of where to regulate is likely to bear directly on the complexity and hence the cost (to society and individual firms) of administrating and enforcing the program,[18] on program coverage, and on the potential for emissions "leakage." It could also affect the politics of gaining support for a particular proposal, especially if some industries are more comfortable with regulation than others. Finally, while cost pass-through is theoretically unaffected by point-of-regulation, in reality imposing the compliance obligation on primary fuel producers or suppliers rather than on entities further down the energy supply chain could facilitate efficient cost pass-through in a way that improves overall program efficacy. Indeed, all of these considerations taken together are, in the Commission's view, grounds for a strong presumption in favor of an upstream system.

Nevertheless, where to regulate and how to allocate are separable questions. Economic analysis shows that, neither will appreciably affect the magnitude of emissions reductions achieved by a particular program, the costs incurred to implement

[17] Experts in the coal and electricity industry have expressed concern that the point of regulation could matter for coal and electricity pricing due to non-competitive situations.

[18] Directly regulated entities will, of course, bear the largest share of administrative costs under a trading program. In a well-designed program, however, these costs should be very small (on the order of tenths of a percent) compared to the allowance value available for allocation.

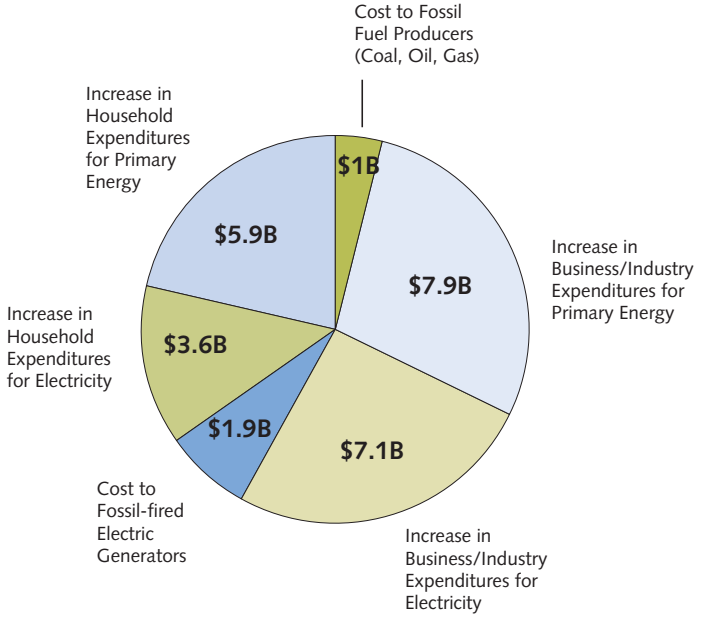
emission-reduction measures, or the incentives faced by individual firms and consumers to reduce emissions.

C. COST INCIDENCE UNDER THE NCEP PROPOSAL

EIA has analyzed sector-level changes in revenues and costs under a greenhouse-gas trading program modeled on the Commission's recommendations (EIA, 2006). In general, the results indicate that the net burden imposed on upstream fossil fuel producers is small under such a policy, regardless of whether they are the entities regulated. Specifically, EIA's analysis suggest that fully compensating primary fuel (i.e., coal, oil, and natural gas) producers for their unrecovered costs under this type of program would require only about 10 percent of available allowances, leaving roughly 90 percent of the allocation available for distribution to energy users further downstream. The electric power sector, by contrast, incurs significantly higher costs than all of the primary fuel producers combined.

Figure 5 summarizes the estimated distribution of net costs to different sectors taking into account the ability of energy suppliers (coal, oil, and gas producers as well as electricity generators) to pass their costs along to energy users. The figures shown are based on data from an EIA analysis of the Commission's original proposal. It is important to stress that the figure does not account for any offsetting income from allowance allocation. In other words, it represents the estimated distribution of net private costs if government were to auction all allowances and throw away the revenues. In reality, of course, nearly all of the "cost" shown in the pie chart (approximately $32 billion per year) would instead be transferred back to households and businesses, either through the recycling of revenues generated by a government auction or by the direct transfer of free allowances to affected entities. As a result, the sum of "costs" shown in the figure far exceeds the cost of the program to society, which, as emphasized throughout this White Paper, corresponds to the cost of emission reduction measures undertaken and is far smaller (on the order of $4 billion per year) than the sum value of allowances in circulation under the program.

Figure 5. Approximate Distribution of Private Costs[19] *Before* any Offsetting Gain from Allocation, Under the Original NCEP Proposal*



** In other words, this estimates the theoretical distribution of net private costs if all allowances were auctioned and none of the revenues were recycled.*

The cost estimates shown in Figure 5 are nevertheless useful as a guide in designing an allocation approach that attempts to distribute the asset value of allowances in proportion to actual cost burdens. For one thing, the pie chart indicates that energy end-users bear a much larger share of costs (again, prior to any offsetting benefits from allocation) than energy producers or suppliers. In fact, the final household share is likely to be even larger than the figure implies because most business end-users will pass some of their costs along in higher prices for goods and services.

[19] Assuming all allowances are auctioned and no revenues are recycled, net private costs for coal, oil, and gas producers and for fossil electricity generators will consist of unrecovered costs to purchase allowances and implement mitigation measures, plus any losses from reduced sales as a result of charging higher prices. For business and household end-users, private costs consist of higher energy costs plus the costs of any measures undertaken to reduce energy consumption.

D. IMPLEMENTATION ISSUES

Cost analyses like those described above provide a useful starting point in designing an allocation scheme consistent with the objective of promoting cost equity. At best, however, they provide only approximate guidelines and leave a number of important implementation issues still to be resolved. One issue is that even within sectors, certain industries and firms will confront a relatively higher burden than others. In other words, to fully compensate fossil electricity producers as a group may, in theory, require a relatively small share (roughly 10 percent) of the total allowance pool, based on that group's share of overall costs as shown in Figure 5. Given that fossil electricity production accounts for approximately 30 percent of national energy-related carbon emissions, this would imply that the industry as a whole should get free allowances equivalent to roughly one-third of its actual emissions. This type of sector-wide estimate, however, masks the fact that some individual power producers—those with significant coal-based generating assets, for example—could require an allocation equivalent to substantially more than one-third of their emissions to be fully compensated for expected profit losses under a greenhouse-gas trading program. Others, by contrast—such as companies with a generating portfolio tilted toward less carbon-intensive generating assets such as natural gas, nuclear, or renewable plants—might require substantially fewer allowances. Similarly, among business end-users, some types of firms—notably those with energy-intensive production processes, such as steel, cement, and aluminum manufacturers—could face substantially higher costs than others.

An allocation methodology that attempted to precisely assess economic burdens at the individual-firm level would, of course, be far too unwieldy and contentious to be practically feasible. In addition it is likely to be extremely difficult—if not impossible—to extract from firms that face lower-than-average costs the surplus needed to compensate firms that face higher-than-average costs. Instead, the likelier outcome—especially in the initial years of program implementation—is that policymakers and regulators will need to expand the share of free allowances allocated to some sectors to provide adequate compensation for those most disadvantaged under the policy. Researchers at Resources for the Future (RFF) have examined the implications of using different decision rules to allocate allowances to the electric utility industry in the context of the northeastern states' RGGI program, which aims to cap regional power-sector carbon emissions (Burtraw et al., 2006). They find that if it were possible to identify all winners under the policy (that is, companies whose profits actually increase as a result of increased demand for lower-carbon electricity) and compensate only those firms that lose value, 34 percent of all available allowances would need to be allocated for free to fully maintain the market value of all companies that generate electricity in the RGGI region. This would leave two-thirds of allowances available for compensation to other affected parties or for other public purposes.

The RFF researchers also explored allocation options where it is not possible for regulators to identify winners and losers at the level of individual firms. Specifically, they attempted to define some simple decision rules for allocating to firms on the basis of their generating portfolio (i.e., their mix of fossil and non-fossil assets) and historic output and emissions, with the aim of maintaining at least a break-even value for all individual firms while still maximizing the number of allowances that remain available for public purposes. In this case a substantially larger share of allowances—77 percent—is allocated for free, leaving 23 percent of the allocation for other purposes. By fully compensating losers without seeking to identify and exclude winners, this approach allows many individual firms—and the industry as a whole—to realize substantial gains in value. Those gains come at the expense of other stakeholders, including electricity consumers and the broader public, to whom a smaller share of the overall allowance pool remains available.

Notably, however, even this approach results in a smaller allocation to regulated industry (and a correspondingly larger allocation for public purposes) than has been typical of most existing emissions-trading programs.

Once the decision has been made to allocate a

"In most existing cap-and-trade programs, historic emissions have been used as the primary basis for allocation to individual firms."

certain share of total allowances to a particular sector, other important implementation issues remain. At a minimum these are likely to involve defining the universe of eligible recipients and identifying metrics to be used in the allocation process. Assuming that it will not be possible to tailor allocation decisions to differentially compensate individual firms, it will be necessary to develop a relatively straightforward and transparent set of rules—using data that are readily available to regulators—for allocating to individual firms or groups from within the pool of allowances reserved for a particular sector. In most existing cap-and-trade programs, historic emissions have been used as the primary basis for allocation to individual firms. Alternative approaches—which some have argued would provide stronger incentives for new technologies and efficiency improvements while avoiding rewards for historically high emitters—involve updating allocations over time and/or awarding free allowances on the basis of output, rather than emissions. For example, allowances could be awarded in proportion to megawatt-hours generated or tons of steel produced rather than on the basis of historic emissions or fuel consumption.

The economic literature is generally critical of these approaches on grounds that any updating system can distort future behavior, while any output-based system could exacerbate windfall gains to firms that are already likely to be competitively advantaged under an emissions trading program (such as utility companies with significant low- or non-carbon generating assets). The concern is that any updating allocation system creates "subsidy effects" that would stimulate some firms to increase their output over the level that would otherwise be economically efficient as a means of capturing a larger future share of allowances. In an updating, output-based allocation system, for example, economic theory suggests that natural-gas-fired electric generators would drop prices and increase output so as to increase their share of future allowances. This in turn would spur increased electricity consumption, reduce incentives to improve end-use efficiency, and drive up demand (and prices) in natural gas markets, creating additional costs. A separate issue, specific to proposals for an output-based method of allocation, concerns the difficulty of establishing simple output metrics for sectors other than the electricity industry.

Updating or output-based allocations do have the advantage that they resolve the conundrum of allocating in perpetuity to firms that have shut down or permanently scaled back their operations (although it should be noted that a gradually expanding auction eventually takes care of this problem as well). Moreover, proponents of updating and/or output-based allocation approaches argue that theoretical concerns about perverse incentives are overstated in the context of real-world regulatory and market constraints that would tend to limit any inefficient subsidy effects. Indeed, recent research suggests that potential distortions produced by an updating approach could be effectively mitigated by updating infrequently and at longer time intervals—for example, once every 10 years based on the previous 10 years of activity or emissions (RFF, 2005). Again, however, the relevance of this debate and the case for considering updating, output-based or other approaches to free allocation will fade over time in the context of any program design that gradually phases these allocations out in favor of a larger auction.

V. Conclusions

Allocation debates are difficult because the issues involved are complex and because parties to these debates often misunderstand, in fundamental ways, how allocation does and does not affect the way an emissions trading program functions. Accordingly, it is worth re-summarizing here, in simple terms, several key points about allocation that emerge from the foregoing discussion:

- Allocation—that is, which entities get allowances, how many allowances they get, and whether allowances are given away for free or auctioned—does **not** change either the cost to society of actual emissions mitigation or the results of the policy in terms of tons of emissions avoided. Allocation can change the *net* cost of the policy to society if it is done in a way that enhances overall economic efficiency, thereby offsetting some of the costs incurred for emissions mitigation (e.g., if government auctions allowances and uses the revenue for efficiency-enhancing tax reforms).

- A greenhouse gas trading program creates a new currency in the form of emission permits or allowances. Because this currency has a real dollar value, debates about allocation are essentially debates about money. *Giving away allowances is like giving away money, in most cases with no strings attached.*

- A firm that receives free allowances has exactly the same incentive to reduce emissions as a firm that receives no free allowances. Using an allowance, regardless of how it was acquired, means giving up something of value (since the firm could otherwise sell the unused allowance in the market place).

- Because free allowances don't change incentives in competitive markets, how allowances are allocated to different entities does not affect where emission reductions occur in the economy or how energy prices change in response to the policy.

- Important caveats to this general rule apply in the electric sector, where a mix of competitive and regulated markets creates the potential for price distortions that could blunt incentives for end-use demand reductions and produce an inequitable distribution of cost burdens across consumers and companies in different regions. One concern is that program costs would be largely passed through to customers in competitive retail markets (allowing generators to "keep" most of the asset value of a free allocation), while companies operating in regulated markets could be required by regulators to use

free allowances to offset price impacts. Since retail markets in the most coal-intensive regions tend to be regulated, this creates the potential for a perverse outcome in which consumers that rely on a more carbon-intensive generation mix see a weaker price signal than consumers that rely on a lower-carbon mix.

- The economic burden imposed on different firms or sectors under a greenhouse-gas trading program is not a simple function of each firm's or sector's emissions or fossil-fuel throughput. Rather, economic burden is a function of ability to pass through costs and other factors.

- To the extent that prices for particular goods or services rise to reflect the value that has been attached to carbon emissions under a greenhouse gas trading program, *all* firms that supply those goods and services will benefit—*whether those firms receive free allowances or not* (in effect, firms that get free allowances will be reimbursed for the opportunity cost of using those allowances). Since individual firms generally cannot set prices, their ability to pass through costs will depend on how markets respond to the policy at the sector or industry level.

- Since giving away allowances is equivalent to giving away money, a free allocation can be used like an upfront payment to compensate entities for their costs under the policy without changing the way entities behave going forward.

- A mixed approach, which combines some free allocation with a partial auction may offer significant benefits over either (a) grandfathering all (or nearly all) allowances or (b) auctioning all allowances. The former approach would have the effect of transferring wealth from consumers to allowance recipients and would generally produce large windfall profits for some firms. The latter would have the effect of transferring wealth from energy producers to taxpayers and would concentrate profit losses in certain carbon-intensive industries.

- Over time, as private firms have an opportunity to adjust their investment decisions to the new incentives created by regulation, the equity rationale for using allocation to avoid economic dislocations in certain industry sectors is likely to diminish. Accordingly, it makes sense to gradually increase the share of allowances auctioned in later years of program implementation to maximize the social efficiency gains available through revenue recycling for tax reform or to support other productive public investments.

The National Commission on Energy Policy has engaged the allocation debate by first articulating some general principles intended to help policymakers navigate the complexities of the issue and adjudicate the multiple competing claims that will inevitably be asserted as any proposal for a broad-based, mandatory greenhouse-gas trading program moves toward adoption. In simple terms, these principles can be summarized as follows:

- Allocation should primarily be used to promote a more equitable distribution of the economic burdens of the trading program, recognizing that the overall burden imposed by regulation is likely to be small in the context of the economy as a whole and that allocation does not affect program incentives or outcomes.

- Some share of available allowances should be used to offset impacts on households, especially low-income households, but without offsetting the price changes necessary to produce efficient emissions reduction.

- Other potential uses of allocation (e.g., technology incentives) should be considered in light of the long-term public benefits they may provide.

- Because allocation is a zero-sum game (there are only so many allowances to give away), policymakers should avoid over-compensating some entities at the expense of others, thereby necessarily diminishing the resources available to advance other important policy objectives.

Combining these broad principles with the results of various cost analyses conducted by the Commission and by EIA suggests that an allocation guided by equity considerations would initially grandfather

no more than roughly 50 percent of the total pool of allowances available on an economy-wide basis to major energy producing or consuming industries, including directly regulated suppliers of primary fuels (coal producers, oil refiners, and natural gas processors), the electric power sector, and energy-intensive manufacturers. This would leave roughly 50 percent of the total pool of allowances to be directed to public purposes, where public purposes could include mitigating impacts on low-income consumers; investing in low-carbon energy technologies and end-use efficiency; creating incentives for cost-effective "off-sector" mitigation activities (such as agricultural carbon sequestration); and reducing the federal budget deficit and/or supporting broader tax reforms. Over time, any initial earmarks for specific purposes will need to be re-evaluated, suggesting a finite limit to these expenditures and transition to general fund contributions.

> *"Given that cost burdens are not equal, there should be no presumption that different industry sectors are entitled to equal shares of allowances, either in absolute terms or as a fraction of their emissions or fuel use."*

Without attempting to distinguish winners from losers at the level of individual firms, this approach should provide enough free allowances to substantially compensate adversely affected industries for their un-recovered costs under the emissions trading program, while also making substantial resources available to provide broader societal benefits. This is a significantly larger share of allowances than has been directed to public purposes in past programs and it reflects the Commission's expectation, again based on available modeling as well as empirical evidence from the EU ETS and other programs, that end-use consumers (households and businesses) will ultimately bear the largest share of program costs and are therefore entitled to a significant portion of the compensation available through allocation.

Within the pool of allowances distributed for free to industry, equity considerations argue for distributing shares to individual sectors in a manner that roughly reflects the incidence of actual cost burdens. Those cost burdens, as noted throughout this White Paper, are not a simple function of emissions or fuel use. Moreover, they are likely to be quite small for some sectors (such as the petroleum industry) that should have little difficulty passing through costs and relatively higher for other sectors (such as the electric power sector and some energy-intensive manufacturers). Given that cost burdens are not equal, there should be no presumption that different industry sectors are entitled to equal shares of allowances, either in absolute terms or as a fraction of their emissions or fuel use.

Among primary fuel producers, for example, available analyses suggest that oil and natural gas producers should be able to fully or almost fully pass through costs with no appreciable demand reductions. Only coal producers could expect to experience more significant profit losses and should be the primary beneficiaries of allocation to fossil-fuel producers (although it is worth emphasizing that overall coal demand continues to grow under the NCEP proposal, just somewhat more slowly than in the absence of a carbon policy).

The other two industry sectors that are most directly affected by greenhouse-gas regulation and should therefore be considered for a share of any grandfathered allocation are energy-intensive businesses (such as steel, aluminum, chemicals, and pulp and paper manufacturers) and the electric power industry. Available modeling analyses suggest that the cost burden imposed on the electric power industry, in particular, is substantially larger than that imposed on primary fuel producers. Given the regulatory complexities and other factors that may affect cost pass-through for this industry, it will be necessary to give especially careful consideration to the incentive and equity implications of different allocation approaches in the electric-sector context. Specifically, policy-makers should explore options that, by reducing the potential for price distortions across regulated versus competitive markets, would promote equitable outcomes for consumers and companies in different parts of the country. How to handle allocation to different entities in the electricity business seems certain to emerge as a critical

> *"…policy-makers should explore options that, by reducing the potential for price distortions across regulated versus competitive markets, would promote equitable outcomes for consumers and companies in different parts of the country."*

question—one that may prove as or more challenging than deciding the question of how to allocate to broad economic sectors out of the available allowance pool as a whole.

The Commission has also come to the view that a strong case exists for a phased approach, in which the share of allowances auctioned expands gradually (and on a known schedule) over time once the program is underway to eventually encompass the great majority of available allowances. The Commission continues to believe, as it did when crafting its original proposal, that allocating a substantial number of allowances for free in the early years of program implementation is pragmatically justified and perhaps politically necessary, even at some risk of overcompensating certain private interests. In fact, it is likely at the outset of any new regulatory regime that corporate interests will be awarded a greater number of free allowances than would be needed if one could precisely match free allocations with the actual incidence of costs. In unvarnished terms, consumers will shoulder more program costs than organized interest groups and shareholders. The Commission believes that this is a reasonable price to pay for establishing a mechanism that begins to reduce the substantial risks of climate change.

Over time, however, the rationale for a free allocation diminishes relative to the considerable societal advantages associated with an auction approach. Simply put, perpetuating an initial allocation that grandfathered most allowances to private interests would compound inequitable outcomes and cannot be justified over the long run. Thus, the Commission no longer takes the view, articulated in its original recommendations, that the share of allowances auctioned should be limited to a maximum of 10 percent.

In closing it is worth cautioning again, as the Commission did in its March 2006 response to a Senate request for input on allocation and other program design issues, that "there is no approach to allocation that can hold harmless all stakeholders or render entirely costless a policy for reducing greenhouse gas emissions." This White Paper has hopefully clarified some important and often counterintuitive aspects of allocation, including the somewhat paradoxical notion that allocation both matters tremendously (from an equity standpoint) and matters hardly at all (from the standpoint of achieving desired environmental objectives). In reality, of course, addressing welfare and equity concerns to the satisfaction of policy-makers and the public is the necessary precondition for achieving real progress toward the environmental objective. As more policy-makers move from the question of *whether* to take action on reducing greenhouse-gas emissions to *how*, equity and welfare are precisely the concerns likely to dominate ongoing debates about future U.S. climate policy.

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DISCUSSION PAPER

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Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program

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RESOURCES FOR THE FUTURE

Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program

Dallas Burtraw, Karen Palmer, and Danny Kahn

Summary

Cap-and-trade programs for air emissions have become the widely accepted, preferred approach to cost-effective pollution reduction. One of the important design questions in a trading program is how to initially distribute the emissions allowances. Under the Acid Rain program created by Title IV of the Clean Air Act, most emissions allowances were distributed to current emitters on the basis of a historic measure of electricity generation in an approach known as grandfathering. Recent proposals have suggested two alternative approaches: allocation according to a formula that is updated over time according to some performance metric in a recent year (the share of electricity generation or something else) and auctioning allowances to the highest bidders.

Prior research has shown that the manner in which allowances for carbon dioxide (CO_2) are initially distributed can have substantial effects on the social cost of the policy as well as on who wins and who loses as a result of the policy. Another concern with a regional cap-and-trade program like the Regional Greenhouse Gas Initiative (RGGI) is the effect that different approaches to allocating emissions allowances will have on the level of CO_2 emissions outside the region, commonly called emissions leakage.

In this research we model historic, auction, and updating approaches to allowance allocation that we call bookends, then model various variations on these approaches. We consider changes in measures such as electricity price, the mix of generation technologies, and the emissions of conventional pollutants inside and outside the RGGI region. We examine the social cost of the program, measured as the change in economic surplus, which is the type of measure used in benefit–cost analysis. We also examine the effects of different approaches to distributing allowances on the net present value of generation assets inside and outside the RGGI region.

We find that how allowances are allocated has an effect on electricity price, consumption, and the mix of technologies used to generate electricity. Electricity price increases the most with a historic or auction approach. Coal-fired generation in the RGGI region decreases under all approaches but decreases the most under updating. Gas-fired generation decreases under historic and auction approaches but increases substantially under updating. Renewable generation increases under historic and auction approaches but decreases slightly under updating as a consequence of the expanded generation from gas. Consistent with the changes in the composition of generation, the decline in emissions of conventional pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury that was expected as a result of the Clean Air Interstate Rule is accelerated substantially as a result of the RGGI policy, particularly under updating. The cost of complying with SO_2, NO_x, and mercury rules declines similarly.

We find that the social costs of the bookend auction and historic approaches are comparable and that the social cost of updating is roughly three times that of the other approaches. At the same time, updating yields greater emissions reductions on a national basis (because it produces less emissions leakage) and greater cumulative reductions in emissions at the national level than historic allocation. Varying the design of the updating approach can reduce its

social costs but generally would increase leakage at the same time. An updating approach with allocation to all generators, including all nuclear and renewables has the lowest social cost within the RGGI region of any policy analyzed, although this result comes at the expense of costs imposed outside the region.

When the approaches to allocation are mixed, we find the changes in electricity price, generation, and emissions are roughly a combination of the performance of each individual approach. In particular, social costs typically are lower under the scenarios that combine an auction with updating than when updating is the exclusive approach to distributing allowances.

Who wins and who loses from the policy varies with the approach to allocation. Under a historic approach, producers in the RGGI region gain substantially and generally are better off than without the program; such is not true under an auction or updating. Producers also gain overall from the policy when a historic allocation is combined with an auction, but the gains are substantially less than in the 100% historic case. Producers outside the region tend to benefit considerably from the higher electricity price in the RGGI region but benefit the least under updating because the effect on electricity price is lowest.

Consumers both inside and outside the RGGI region are adversely affected under all allocation approaches but much less so under updating because the change in electricity price is lowest. One exception is when eligibility for allowances under an updating allocation is limited to nonemitters only, in which case the electricity price increases substantially.

Different types of generators fare differently under the various allocation approaches. Asset values for all types of generators are highest under a historic approach, although the difference between historic and auction approaches is small for nuclear generators. Compared with the baseline, both nuclear and existing gas-fired generators in the RGGI region gain under an auction. Only gas-fired generators gain under the bookend approach to updating, although nuclear generators benefit as well under updating designs that include them among those eligible for allowances. Coal-fired generators lose the most under updating.

Moving from 100% updating to auctioning an increasingly larger share of allowances generally has a positive effect on asset values for all fuel types including coal. The one exception is that moving from 50% auction and 50% updating to 100% auction has a negative effect on the asset values for coal.

Finally, we conduct sensitivity analyses with higher natural gas prices and constraints on electricity transmission capability. The social cost of the RGGI program does not appear to be sensitive to these constraints. Higher gas prices or transmission constraints alone impose significant costs that are larger than the effect of adding the RGGI policy. For example, their substantial effect on electricity price is greater than the added effect imposed by the RGGI program. The constraints that are modeled do not appear to have a strong impact on RGGI implementation. We also conduct a sensitivity analysis with renewables portfolio standard policies in place throughout the region. The resulting prices of electricity and CO_2 emissions allowances are slightly lower than without the renewables policy.

Key Words: emissions trading, allowance allocations, electricity, air pollution, auction, grandfathering, generation performance standard, output-based allocation,

cost-effectiveness, greenhouse gases, climate change, global warming, carbon dioxide, sulfur dioxide, nitrogen oxides, mercury

JEL Classification Numbers: Q2; Q25; Q4; L94

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Contents

1. Introduction **1**

1.1. Project Goals 3

1.2. Summary of Findings 4

1.3. Conceptual Background 5

2. Research Strategy **7**

2.1. Modeling Scenarios 9

2.1.1. Central Case Baseline 10

2.1.2. Policy Scenarios 12

2.2. Measures for Evaluation 13

2.3. Simulation Model 14

3. Results for "Bookend" Scenarios **15**

4. Variations in Results for Historic Approach **22**

5. Variations in Results for Updating Approach **22**

6. Mixed Approaches **24**

7. Constrained Cases **26**

8. Renewable Portfolio Standard Cases **28**

9. Conclusion **29**

References **32**

Tables **34**

Figures **54**

Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program

Dallas Burtraw, Karen Palmer, and Danny Kahn*

1. Introduction

The Regional Greenhouse Gas Initiative (RGGI) is an effort by nine Northeast and Mid-Atlantic states to develop a regional, mandatory market-based cap-and-trade program to reduce greenhouse gas (GHG) emissions. The effort was initiated formally in April 2003 when Gov. George Pataki of New York sent letters to governors of the Northeast and Mid-Atlantic states. Each of the nine participating states (Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) has assigned staff to a working group that is charged with developing a proposal in the form of a model rule by 2005. Initially, the program will address carbon dioxide (CO_2) emissions from the electric power sector. If successful, the program could serve as a model for a national cap-and-trade program for GHG emissions.

One of the most important and contentious features of an emissions trading program is how emissions allowances are initially distributed. Several distribution approaches have been considered in other regulatory contexts. One such approach is to distribute allowances on the basis of **historic** measures of electricity generation; this approach is often called *grandfathering* because it distributes allowances without charge to incumbents in the industry. Another approach is to regularly **update** the calculation underlying the allowance distribution based on current- or recent-year data. Like distribution based on historic data, an updating approach distributes allowances free of charge and also could distribute according to various measures, such as the share of electricity generation, emissions, or heat input (related to fuel use) at a facility. The primary alternative to these free distribution approaches is the sale of allowances through an

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auction, directly or indirectly (e.g., allowances may be distributed for free to third parties such as energy consumers or their trustees, which then sell allowances through an auction). A key feature distinguishing types of auction approaches is the dispensation of revenues raised under the auction. Revenues could be returned to industry or consumers, used to compensate communities, invested in energy conservation, or used to offset other needs for tax revenue by government.

Each of these approaches has proponents, and each has a precedent. The most well known emissions cap-and-trade program—the sulfur dioxide (SO_2) emissions trading program initiated under the 1990 Clean Air Act Amendments—distributes allowances primarily on the basis of a historic measure of generation (heat input) at electricity-generating facilities. The second-largest U.S. emissions trading program is the nitrogen oxides (NO_x) regional cap-and-trade program in 19 eastern states. Under this program, distribution is determined at the state level. Most states use some historic measure as a basis for distribution, but states also use updating for some portion of the allowances. Updating is also evident in one form in Sweden, where beginning in 1992 the revenues from a tax on NO_x emissions were recycled to industry on the basis of each emitter's share of electricity generation.[1] Auctioning has a precedent in the state of Virginia, which distributed a small portion of its NO_x allowances in the regional cap-and-trade program through a revenue-raising auction. Recent legislative proposals for the regulation of multiple pollutants from the electricity sector also have involved all three of these basic approaches to various degrees.

There is little evidence comparing the experience with different approaches to initial allowance distribution, but several theoretical and policy studies have examined efficiency and distributional issues. These studies have examined various pollutants, and their findings differ somewhat depending on which pollutant is modeled. Moreover, an important distinction is that the RGGI policy is aimed specifically at a nine-state region of the country. The RGGI region has its own mix of technologies for electricity generation that have a direct bearing on the evaluation of the approaches to distributing allowances. The region is characterized by competition in retail electricity markets, setting it apart from the nation as a whole, which has a mix of regulation. Also, open state borders and the electricity transmission grid pose challenges to policy enforcement. Any environmental policy that increases costs in the region is likely to cause some emissions leakage to outside the region as economic activity or electricity generation moves to

[1] Hoglund (2000); Sterner and Hoglund (2000).

avoid regulation. It is noteworthy that the Northeast faces higher natural gas and electricity prices than other parts of the nation.

Two major types of issues affect the choice of a mechanism for distributing allowances in the RGGI region. **Distributional issues** affect consumers vis-à-vis producers through electricity price changes and affect various producers in different ways through changes in the valuation of generation assets. **Economic efficiency issues**—the cost-effectiveness of the program within the electricity sector—affect everyone. We do not consider secondary costs imposed outside the electricity sector due to changes in electricity price or fuel prices.

1.1. Project Goals

The questions that we sought to address in this research are the implications of different approaches to the initial distribution of CO_2 allowances.

- What are the effects on the costs of the program? We note that cost—and other indicators of efficiency—can be measured in various ways.
- What are the distributional consequences? Attention can be focused on distribution between consumers and producers or among producers that have a diverse set of interests with various portfolios of generation technologies.
- How effective are allocation methodologies that favor certain technologies (including energy conservation technologies) on the consumer side of the meter, and what are the trade-offs?
- Would combinations of auctioning (or "grandfathering to consumers," a form of auctioning) and no-cost allocation compensate companies but still provide for an efficient outcome?

In the course of the research, additional questions surfaced that also are discussed below.

1.2. Summary of Findings

In brief, we find that

- The CO_2 allowances created by the program have a value that is at least four times as large as the social cost of mitigation, suggesting that allowance distribution is a potentially important source of compensation.
- Because of electricity deregulation in the Northeast, allowance value is reflected in electricity price to an equal degree for auction and historic approaches to distribution.
- The social costs of auction and historic approaches are similar. However, producers gain substantially under a historic approach, and in the aggregate, they are better off than without the program.
- Updating yields a higher allowance price, a lower electricity price, and more electricity generation in the RGGI region than the other approaches.
- The social cost of an updating approach is about three times greater than that of an auction or a historic approach.
- The effect on producers is measured by the change in the market value of generation assets. Under the historic approach, the market value of all types of generation assets gain substantially, and in the aggregate, the industry gains substantially.
- Under an auction, the market value of coal assets falls substantially, but in the aggregate, the industry is not affected dramatically.
- The market value of coal assets—and of all assets in the aggregate—fall by the greatest margin under an updating approach.
- Coal-fired generation falls under all approaches but falls the most under updating.
- Gas-fired generation falls under historic and auction approaches but increases substantially under updating.
- Leakage of CO_2 emissions to outside the RGGI region is greatest under historic and auction approaches and lowest under updating.
- Emissions of conventional pollutants in the RGGI region fall substantially under all approaches to allocation but fall the most under updating.

- The cost of complying with SO_2, NO_x, and mercury rules falls considerably within the RGGI region because of efforts to reduce CO_2 emissions.
- Varying the approach to updating (including who is eligible to receive allowances) can yield very different results. One approach, updating allocation to all generators, has the lowest social cost within the RGGI region of any policy analyzed. However, the benefit comes at the expense of costs imposed outside the region.
- Combined approaches generally lead to intermediate outcomes.
- In the aggregate, variations in baseline assumptions such as higher natural gas prices or transmission capability constraints tend to benefit producers in the absence of the RGGI policy. These constraints have a substantial effect on electricity price that is greater than the added effect imposed by the RGGI program.
- The cost of the RGGI program does not appear to be sensitive to the price of natural gas or the existence of constraints on electricity transmission capability.
- The existence of a renewable portfolio standards (RPS) policy causes the CO_2 allowance price to fall slightly. Coal generation remains at a level that is greater than in the absence of the RPS, and gas generation falls to a lower level.

1.3. Conceptual Background

Allowance distribution is one of the most contentious issues policymakers face when designing a cap-and-trade program. Allowances are a valuable asset, and their distribution has implications for both equity and efficiency. Many economists and other analysts advocate auctioning allowances rather than distributing them at no cost. The benefits of auctioning include providing a source of revenue that could potentially address inequities brought about by a carbon policy (e.g., by compensating consumers for high prices or communities that are severely affected) or be used to make investments in energy conservation. Alternatively, the revenues from auctioning allowances may have economy-wide efficiency benefits if they are used to reduce taxes.

In contrast, companies participating in a cap-and-trade program usually oppose auctions. They argue that because they already bear the costs of emissions reduction obligations, they should not also have to purchase the emissions allowances up front. The net cost to producers of the emissions trading program depends on the difference between the change in producer revenue and the change in cost. Regardless of how allowances are distributed, firms are expected to pass along some of the resource cost associated with reducing emissions and some of the

opportunity cost (market value) of emissions allowances in product prices, thereby causing revenues to increase. The justification for the free distribution of emissions allowances is to reduce the change in costs for industry and thereby provide compensation. An auction does not provide this form of compensation because it makes firms pay for allowances.

The degree to which producers pass on (in electricity prices) the resource and allowance costs varies with the presence or absence of price regulation and with the technology that sets marginal cost in competitive regions. In the case of nationwide CO_2 regulation, Burtraw et al. (2002) find that the free allocation of emissions allowances can dramatically overcompensate the electricity industry in the aggregate, although different parts of the industry are affected very differently. In the case of SO_2, Bovenberg et al. (2003) also find that free allocation as envisioned under the Bush administration proposal for SO_2 control would overcompensate industry. A central issue for RGGI planners is whether the free allocation of CO_2 emissions allowances in the Northeast provides a level of compensation that is proximate to or potentially surpasses (perhaps by a significant degree) compliance costs.

Recent research also has shown that the initial distribution of allowances can affect the economic cost of the policy as well as who wins and loses. Two separate bodies of literature have developed with regard to the economic costs or general efficiency issues related to trading programs for emissions permits. One explores the role of preexisting distortions away from economic efficiency in labor and capital (factor) markets due to the presence of taxes on labor or capital income (Bovenberg and de Mooij 1994, Parry 1995) and relies primarily on computable general equilibrium simulation models to estimate the potential efficiency consequences of different approaches to allocation (Bovenberg and Goulder 1996, Goulder et al. 1997, Goulder et al. 1999, Parry et al. 1999, Smith et al. 2002). Cap-and-trade programs for CO_2, SO_2, and NO_x have been analyzed in competitive product markets (electricity regulation is not considered explicitly), and results favor an auction as the most efficient approach to the initial distribution of emissions allowances when the revenues are used to reduce preexisting taxes. We do not consider these issues in this paper.

The second body of literature, to which this paper contributes, examines the role of preexisting distortions away from economic efficiency in product markets (such as electricity) due to the difference between price and marginal cost, a condition that is common throughout the economy and endemic in the electricity sector. In the case of CO_2, an auction approach to distributing emissions allowances results in a substantially lower social costs than an updating approach based on output or a historic approach (Burtraw et al. 2001, 2002; Beamon et al. 2001). This result is largely attributable to the fact that electricity prices are set by cost-of-service regulation in much of the country, and these prices differ from marginal cost. In regulated

regions, the opportunity cost of an emissions allowance given to a firm for free under an updating or a historic approach is not directly reflected in the electricity price (i.e., it is valued at an original cost of zero). However, the cost of an auctioned allowance is reflected in regulated electricity prices, and this cost can widen or narrow the gap between regulated prices and efficient prices. Typically, though, it tends to narrow the gap between price and marginal cost and improves economic efficiency.

In the RGGI region, however, electricity markets are deregulated, and retail prices are based on marginal costs rather than regulated average cost of service. In this case, the previous literature suggests there is little difference between auction and historic approaches to distributing allowances from an efficiency perspective. In one case, the revenues go to government; in the other, they go to industry. However, because investment and compliance behavior are expected to be nearly identical, so is the change in electricity price. In competitive electricity markets, an updating approach is expected to have greater social costs than an auction or a historic approach because it does not provide the same incentive through higher prices for consumers to improve the energy efficiency of energy use.

In addition to distributional and efficiency effects, a third measure that also may distinguish approaches to allocation is the creation of incentives for the introduction of new or cleaner technology (Energy and Environmental Analysis, Inc. 2003). An updating approach provides generators with an incentive to increase generation by all sources because of the implicit output subsidy, whereas dirty sources are penalized in terms of variable costs due to the cost of allowances. In the case of CO_2, Burtraw et al. (2002) find updating leads to substantially more generation with natural gas and less with coal.

Another issue of central interest to the RGGI is the leakage of electricity generation, CO_2 emissions, and economic activity to outside the RGGI region. For instance, leakage could result if electricity generators decide to use power plants outside the region to generate more electricity to be imported into the region over the transmission grid. Leakage could also occur if electricity customers decide to self-generate rather than purchase electricity off the grid in response to increased electricity price. Previous analysis suggests that the method of distributing emissions allowances can have an effect on the degree of leakage and ultimately on the cost-effectiveness of the emissions trading program.

2. Research Strategy

We use a model that has a high level of detail about technology and institutions to calculate investment and dispatch of generation capacity in the electricity sector. The model

projects changes in the economic behavior of consumers and producers in response to the climate policy and other changes that result from those behavioral responses.

Point estimates of changes in key variables such as electricity price, electricity consumption, and producer profits are reported, but the main focus of this exercise is the changes that are predicted to result from baseline in response to variations in the policy design. The RGGI staff working group is planning a detailed modeling exercise using the Integrated Planning Model (IPM) at a greater level of detail and with greater precision regarding assumptions about the future of the electricity industry in the region and the design of the CO_2 policy and other regional policies. Our model simulations are expected to produce results very close to those of the more comprehensive effort, as they are conducted with the same general assumptions. We do not adopt the precise assumptions of the RGGI modeling group, partly because of the expense involved and also because we aim to characterize the landscape of qualitative considerations with more model runs than we could afford otherwise. For example, two key differences include our lack of modeling of rules governing transmission that could mitigate leakage and our lack of modeling of recent renewable policies in the Northeast. Our simulation model provides a laboratory for examining a wide range of options as well as the variations among these options while preserving the important quantitative and qualitative differences of the different options, which can then be validated in IPM.

We solve the model for a baseline scenario (described below) through 2025. Then, in policy scenarios, we introduce the RGGI and vary the approach to the initial distribution of emissions allowances. Results are reported first for three distinct approaches that represent "bookends" for the type and mix of approaches that have been widely discussed. The analysis of bookend policies provides a useful pedagogy for understanding the trade-offs among approaches. Subsequently, we investigate several variations on the bookend approaches, mixed approaches, and changes in the baseline parameters.

The level of aggregation in the model has both strengths and limitations. It is appropriate for estimating costs from a social and regional perspective and for understanding the distribution of costs between consumers and producers. The model also captures differentiation among fuels and technologies and the effects of policies on the market value of existing and new generation assets. The effect on existing assets can be aggregated to represent the portfolio owned by firms and thereby to provide a good measure of how shareholders are affected. However, the model does not capture some short-run idiosyncrasies that affect individual plants such as take-or-pay fuel contracts. Intra-regional transmission bottlenecks that may cause a spread between the regional high and low electricity prices are not reflected in the model. However, to the extent such constraints are observed, they are represented—albeit somewhat imprecisely—through out-

of-merit-order dispatch and must-run constraints, which are captured with a shadow price component of variable costs that is calibrated to approximate actual operation in recent years.

The model also does not capture the effects of long-term contracts for electricity generation from nuclear plants and some fossil fuel–fired units. In several RGGI states, when nuclear and other plants were divested by the local integrated utility, the distribution utility signed long-term contracts for much of the generation from those facilities. These contracts limit the ability of certain generating units to profit from increases in the short-term market price of electricity resulting from a RGGI policy. However, in a post-transition competitive market, the contracts do not limit the electricity retailer's ability to charge a price based on the marginal cost of electricity sold in shorter-term markets, because the retailer that has purchased power under a long-term contract with a generator could turn around and sell that power in the spot market, where the RGGI policy could be raising costs of the marginal generator. Therefore, the spot market price defines the opportunity cost of selling power to retail customers, and electricity retailers (not explicitly represented in our model) will profit from the RGGI policy at the expense of those generators that have their power committed for sale under long-term contracts. Thus, in a competitive market, the existence of long-term contracts for wholesale power will affect which producers and retail suppliers profit from the RGGI policy but will not affect consumer costs.[2]

Finally, this study does not investigate the issue of leakage in detail. We find evidence that the approach to the initial distribution of emissions allowances affects leakage, but we do not offer a systematic analysis. Also, we do not compare the impact of allocation methods with other factors, such as the level of the cap. We do explore alternative natural gas prices in a sensitivity analysis.

2.1. Modeling Scenarios

The model is solved for a baseline, and policy scenarios are analyzed relative to measures in the baseline. We describe the central case baseline first. Later, we vary baseline assumptions about natural gas prices and transmission capability in a sensitivity analysis.

[2] Electricity retailers will be constrained from passing on wholesale market price increases resulting from the RGGI policy during the transition period if retail prices are effectively capped or if prices are set based on the weighted average of prices for different term contracts for power, as is done for default power in several RGGI states. Our analysis is about the longer-term effects of RGGI on electricity prices and not effects during the transition period.

2.1.1. Central Case Baseline

Throughout this analysis, we make several assumptions about underlying policies—federal and state environmental policies as well as market regulatory policies—that affect the performance of electricity generators. In the baseline case, we assume electricity generators face requirements under the Nitrogen Oxides (NO_x) State Implementation Plan (SIP) Call; Title IV of the 1990 Clean Air Act Amendments; and the Bush administration's draft Clean Air Interstate Rule (CAIR) for SO_2, NO_x, and associated mercury. The seasonal NO_x SIP Call for 19 eastern states is in force for the 2008 simulation and replaced by the annual NO_x constraint for a 28-state region under CAIR for the other simulation years.[3] The annual emissions constraints for SO_2 are drawn from the U.S. Environmental Protection Agency's (EPA's) modeled solution for how the regional CAIR rule would interact with the national Title IV regulation. Regional annual SO_2 allowance distributions are capped at 3.9 million tons beginning in 2010 and 2.7 million tons beginning in 2015. Actual emissions will be higher over the modeling time horizon because of the allowance bank. We follow EPA modeling of the SO_2 CAIR and Title IV within one national trading regime. A single national region is characterized using model results that account for the opportunity to use Title IV allowances within the CAIR region at an offset ratio that changes over time.[4] The actual emissions caps that we model are reported in Table 1.

Under CAIR, regional annual NO_x emissions distributions are capped at 1.6 million tons beginning in 2010 and 1.3 million tons beginning in 2015. In the model, the NO_x caps include an adjustment of about 331,000 tons for units outside the CAIR NO_x region but within the Mid-Continent Area Power Pool (MAPP) and New England electricity regions.

The national annual allocation of mercury emissions allowances is to be capped at 34 tons beginning in 2010 and 15 tons beginning in 2018. We model a cap-and-trade program for mercury. We adopt as our mercury emissions cap EPA's prediction of annual emissions in the presence of a $35,000/pound ceiling on the price of mercury permits and the ability to bank allowances. Under the cap-and-trade programs for the three conventional pollutants, emissions allowances are distributed on a historic basis.

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[3] The 28 states are Alabama, Arkansas, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.
[4] Docket OAR-2002-0056-0338.

We include all announced new source review (NSR) settlements in our technical assumptions about emissions control at existing generators.[5] We also include a representation of two federal policies to promote renewables. We assume that the renewable energy production credit (for dedicated biomass and wind generation) is extended. Additionally, we incorporate a perpetual 10% investment tax credit for new geothermal resources.

We also include several state-level environmental and renewables policies. To capture the anticipated effects of compliance with state-level RPS and other state-level renewables policies and programs (including green pricing on investment in new renewables), we incorporate the U.S. Energy Information Administration's (EIA's) estimates of several new renewable resource investments to be put into place to comply with these policies. In the Northeast, we include policies in Connecticut, Massachusetts, and New Jersey.[6] However, we do not include policies in Maine, New York, Rhode Island, Maryland, or Pennsylvania in our central baseline case or policy cases. We expect that in the baseline scenario (e.g., in the absence of the RGGI policy) these policies could reduce emissions, CO_2 allowance price, investment in gas-fired generation, incremental compliance cost, and leakage. We conduct a sensitivity analysis of the baseline and historic bookend cases to identify the effects of including the RPS policies in one of the RGGI policy cases. The emissions reductions in our model could therefore be thought of as a more stringent policy on CO_2 because emissions reductions are greater than in the baseline scenario. We also include the anticipated effects of state-level multipollutant policies in Connecticut, Massachusetts, Missouri, New Hampshire, North Carolina, Texas, and Wisconsin.[7]

We assume that electricity prices are set competitively in six North American Electric Reliability Council (NERC) regions (New York, New England, Mid-Atlantic states [MAAC], Illinois area [MAIN], the Ohio Valley [ECAR], and Texas [ERCOT]) and that there is time-of-day pricing of electricity for industrial customers in these regions. In all other regions of the

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[5] NSR settlements are those that electricity generating companies have reached with the federal government to bring their plants into compliance with NSR requirements for emissions reductions that the government claims were not met by past investments at specific facilities.

[6] We also include the effects of state-level RPS policies in Arizona, California, Nevada, Texas, and Wisconsin; the effects of green pricing programs in several states; and renewables mandates in Minnesota. For more information see EIA 2004.

[7] Several states have passed laws limiting emissions of some combination of NO_x, SO_2, mercury, and CO_2 from electricity generators. Most of these laws or regulations—such as new regulations in Connecticut and Massachusetts that limit nonozone season emissions of NO_x—are formulated as limits on emission rates. The largest state actions are in North Carolina and New York, which have recently placed emissions caps on its largest coal-fired plants. A similar plan has been adopted in New Hampshire for all existing fossil fuel–fired generators.

country, we assume that prices are set according to cost-of-service regulation at average cost. We simulate the model through 2025 and extrapolate our results to 2030 in order to calculate returns to investment choices.

2.1.2. Policy Scenarios

In all policy cases, the annual CO_2 emissions target is set by calculating a 20% decline from 2008 baseline emissions levels in the RGGI region, with the emissions reduction to be phased in on a linear basis between 2008 and 2025. The RGGI region is characterized as the nine-state region including New England, New York, New Jersey, and Delaware.

We give special consideration to new plants forecast for the MAAC region of NERC. Unless otherwise noted, we assume all new plants fired by fossil fuel (e.g., natural gas) located in MAAC are built anywhere in the Mid-Atlantic region in the baseline scenario and built outside the RGGI region (i.e., in Maryland and Pennsylvania) in all policy cases. Where plants will be built many years into the future is unknowable today. Access to transmission is one important factor, along with others that cumulatively may be more important than the presence of the RGGI policy. However, given the lack of transmission constraints within the Mid-Atlantic region in the model, with all other things equal, it makes sense that a plant locating in the region would choose a location that avoids the constraints of the RGGI program. This model design is one way in which model-estimated leakage is likely to overestimate the actual leakage that would occur. Hence, we do not focus on the quantity of leakage but instead compare the different approaches to allocation in qualitative terms.

Furthermore, when nonemitting renewable plants qualify for the allocation of emissions allowances, we assume that all new plants built in the Mid-Atlantic region qualify. This assumption is for modeling convenience but also accounts for the expectation that a qualifying facility would be more likely to locate on the RGGI side of a political boundary, all other things equal, if it could realize cost reductions by doing so. In fact, the portion of the Mid-Atlantic region located inside the RGGI region has limited renewable resources. However, to facilitate a consistent comparison between the baseline and policy cases, we always account for all new renewable investments in the entire Mid-Atlantic region as locating within the RGGI region.

The three bookend approaches to the distribution of emissions allowances that we analyze are historic (to emitters on the basis of historic generation in 1999), auction, and updating (to emitters on the basis of recent-year generation with a 2-year lag). Variations for each bookend case are listed in Table 1. Two choices characterize each scenario: Which generators are eligible for emissions allowances, and on what basis are allowances distributed?

We consider four mixed approaches. We also consider two types of constraints on the future of electricity supply: constrained transmission capability and higher natural gas prices.

2.2. Measures for Evaluation

The measures for evaluating these policy scenarios include changes in electricity price, economic measures of efficiency (including resource costs and changes in economic surplus), and changes in the value of existing generation assets. Efficiency results are measured in 1999$ from 2003 to 2030 and valued according to the usual method used in benefit–cost analysis, that is, the net present value (NPV) of Change in Economic Surplus = Change in Producer Surplus + Change in Consumer Surplus + Change in Government Revenues.

Producer surplus is the change in economic profit—that is, the value of revenues in excess of costs, where costs include payments to all factors of production, including labor, fuel, and annual capital costs. This measure is different from an accounting measure of profit, which typically also includes payments to invested capital, which are not considered economic profit unless those payments exceed the market rate of payments to capital. Consumer surplus is an analogous measure, reflecting the well-being of consumers in excess of what they have to pay for electricity services.

The auction mechanism also yields government revenues that could be used to fund public benefit programs, to compensate those who are adversely affected by the program, or for some other purpose. In any case, these revenues have a value that offsets some of the cost reflected in a decline in producer and consumer surplus under the auction. The public finance literature offers the guidance that the value of a dollar raised from emissions fees is greater than face value when that revenue is used to offset preexisting taxes such as labor or capital income taxes that impose inefficiency in the economy (Goulder et al. 1999). We take a cautious posture in this regard, assuming revenues have a social value just equal to their face value.

One should note that economic efficiency is only one measure of public policy. Equity and other concerns may override efficiency. An increase in electricity price may be viewed as enhancing efficiency, for example, because it provides a signal to encourage the purchase of energy-efficient appliances, but it also could cause hardship.

We look at the distributional consequences of different approaches to allocation for the industry by evaluating how these approaches affect the market value of generating assets. Asset values are measured in 1999$ by calculating the NPV of producer surplus from different types of electricity generators from 2003 to 2030. We aggregate generators by fuel, for new and existing

generators, and look at regulated and competitive regions separately as well as the nation as a whole.

2.3. Simulation Model

We use Resources for the Future's (RFF's) electricity market model, Haiku, to analyze the effects of different approaches to allocation under a RGGI cap-and-trade program for GHGs focused on the electricity sector.[8] Haiku looks at the effects of the policies on the behavior of electricity producers and consumers as well as the resulting implications for costs, prices to consumers, and the emissions levels and locations. It is a national equilibrium model of 13 regional U.S. electricity markets with endogenous investment in and retirement of generation and pollution control capital.

The supply side of the model is built using capacity, generation, and heat rate data for the complete set of commercial electricity plants in the United States from various EIA datasets. For modeling purposes, these plant-level data are aggregated into 39 representative plants in each region. The capacity for a model plant is determined by aggregating the capacity of the individual constituent plants in a given region that are of the same type as the model plant.[9] However, no region contains every one of these model plants. For example, the New England region does not contain any geothermal plants. Factor prices (such as the cost of capital and labor) are held constant, and fuel price forecasts are calibrated to match EIA price forecasts (EIA 2004). Fuel market modules for coal and natural gas calculate prices that are responsive to factor demand.

The demand side of the market is characterized by three customer classes, with demand divided across three seasons and four time blocks within each season. The quantity of electricity demand responds to changes in electricity price. The level of electricity demand is calibrated to match EIA forecasts for the baseline and elasticity estimates drawn from the academic literature

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[8] The model has been used in several peer-reviewed publications and was compared with other models in two sessions of the Energy Modeling Forum (EMF 1998, 2001). Paul and Burtraw (2002) provide further documentation.

[9] A model plant is defined by the combination of its technology and fuel source (coal, natural gas, oil, hydro, or nuclear). For example, some steam plants run on oil, others on natural gas; the same is true for gas turbine plants. Coal is different from the other fuels in that it has 14 subcategories based on the originating region and sulfur content. Coal users are broken down into demand regions that have different costs associated with each type of coal, which reflect the varying interregional transport costs. To reduce SO_2 or mercury emissions, model plants might find it more cost-effective to change the type of coal used than to install new pollution controls.

and other sources. Electricity trade between regions is also allowed, subject to transmission losses and physical transmission constraints.

3. Results for "Bookend" Scenarios

In this section, results are presented first for a set of bookend scenarios that are compared with a baseline scenario that represents a forecast in the absence of the RGGI. In subsequent sections, results are presented for several sensitivity analyses that consider variations on the bookend scenarios, combinations of features, or different assumptions about features of the baseline.

Baseline emissions for the nation and for the RGGI region are presented in Table 2. Emissions of the conventional pollutants (NO_x, SO_2, and mercury) are expected to fall between 2008 and 2025 in the baseline scenario because of CAIR implementation. State multiple-pollutant rules that are not modeled would strengthen this trend.

However, CO_2 emissions in the baseline scenario are shown to rise by 20% over the same period nationally and by nearly the same rate within the RGGI region. In 2008, CO_2 emissions in the RGGI region form the basis for calculating emissions targets. Under the RGGI targets, CO_2 emissions are assumed to decline linearly by 20% between 2008 and 2025, leading to an emissions target of 100 million tons in 2025.

Results comparing the baseline scenario with the three bookend policy cases are reported in Tables 3–5. In the baseline, the average annual retail electricity price is expected to be $103.4/MWh in 2025 in the nine-state RGGI region and $66.6/MWh nationally—about two-thirds of the price in the RGGI region.

The policy bookends include 100% allocation through three different mechanisms: The historic approach would distribute allowances to CO_2 emitters in the region on the basis of their historic share of generation in 1999, the auction would distribute allowances through sale by the government or another public institution, and the updating approach would distribute allowances to emitters on the basis of their share of total generation by emitters during the 2 preceding years. We make several key observations by comparing the pure versions (100% allocation in each case) of these approaches.

Electricity price increases in all scenarios. As indicated in Table 3, the average electricity price is higher in each case than in the baseline.

Consumers prefer the updating approach because it leads to the lowest electricity price of the three policy scenarios. Similarly, in each case, total generation within the RGGI region falls relative to the baseline, but it falls the least—by less than one-half as much—under

updating than under the other approaches. This attribute of updating follows from the incentive to increase electricity generation in order to earn a larger award of emissions allowances.

Coal-fired generation falls under all approaches but falls the most under updating. The greater decline in coal under the updating approach—to one-half the level of the other approaches—is a result of the improvement in the relative cost of generation with natural gas compared to coal.

Gas-fired generation falls under the historic and auction approaches but increases substantially under updating. The emissions rates for natural gas are below the average for emitting sources, whereas those for coal are above average. Hence, natural gas is the preferred technology for responding to the incentive to expand production under updating. Generation with natural gas increases by 33% under updating relative to the baseline but falls by about 12% under the other approaches. The price of CO_2 emissions allowances is twice as high in the updating case because of the overwhelming incentive to increase gas-fired generation, which more than compensates for the decreased average emissions from natural gas sources.

Figure 1 illustrates the going-forward costs of electricity generation for a representative existing coal plant and a new natural gas combined cycle plant in the RGGI region. *Going-forward costs* are the expenses associated with bringing power from this plant to market in the future: fuel cost, fixed costs, and operating and maintenance costs. For existing and new plants, going-forward costs also include new capital investments in post-combustion pollution controls, operational costs, and the cost of emissions allowances net of the permit allocation to comply with the CAIR rule; for new plants, they also include capital costs.

In Figure 1, the component labeled CO_2 represents the opportunity cost of using CO_2 allowances under the RGGI policy that is added to going-forward costs, and permits represent the value of the allocation of CO_2 permits to the plant. In the bookend updating case, emissions allowances are earned by generating electricity, and their value is subtracted from other costs to arrive at the net cost of future generation. Because the change in net cost is less than the change in gross cost, the change in electricity price in a competitive power market is relatively small with an updating approach.

The value of CO_2 allowances awarded per megawatt-hour of generation is the same for the coal and gas plants; however, the CO_2 cost is more than twice as great for the coal plant. Hence, the allocation is equal to less than half of the CO_2 cost at the existing coal plant and greater than the CO_2 cost at the new natural gas plant. Net costs at the coal plant (about \$48/MWh) remain slightly below the net costs at the gas plant (about \$52/MWh). Nonetheless, the cost difference is negligible compared with the difference in the absence of the RGGI CO_2

policy, where the cost of the coal plant ($30/MWh) is substantially less than the cost at the gas plant ($53/MWh).

With the bookend historic approach, only the existing coal plant earns an allocation. The plant is endowed with the allowance value, regardless of whether it generates electricity. Hence, the value is not subtracted from going-forward costs. The magnitude of the CO_2 cost is much smaller with a historic approach than with an updating approach because the price of emissions allowances is lower.

Figure 1 also illustrates the influence of the RGGI CO_2 policy on the cost of compliance with the CAIR rule for conventional pollutants. One sees that the cost of SO_2 and mercury control per megawatt-hour at the existing coal plant is greater under historic allocation of CO_2 emissions allowances than under updating, primarily because the cost of acquiring allowances for SO_2 and mercury exceeds the plant's endowment under CAIR and Title IV. Generation at the existing coal plant under the historic approach to CO_2 allowances is roughly twice as large as under updating. The values represented in the graph are model solutions after costs are spread over the equilibrium level of generation under each policy. Note also that fuel costs per megawatt-hour are greater under the historic approach when the plant is more heavily used because more expensive fuel is used to help the plant comply with the CAIR rule.[10]

Renewable generation does relatively poorly under an updating approach. Renewable generation is less than with the historic approach and even less than in the baseline scenario. The lower level of renewable generation is a familiar result in this and other models. Typically, natural gas and renewables compete for new generation, and market share gains for one come at the expense of the other (Palmer and Burtraw 2004). This result changes when renewables qualify for a share of emissions allowances.

The decline in conventional pollutant emissions in the Northeast accelerates dramatically under the RGGI. Emissions are expected to fall substantially over time in the baseline scenario. However, the RGGI policy dramatically accelerates this trend. Emissions of conventional pollutants fall in all cases, but as a consequence of the shift in generation from coal to natural gas, conventional pollutant emissions are substantially lower under an updating

[10] This representative plant is a "model plant" in the simulation model that aggregates constituent plants of similar technological characteristics, so the results are the average for this group of constituent plants. Under the historic approach, nearly twice the capacity of this plant still exists in 2025 compared with under updating, and the amount of wet scrubbing in place is greater in absolute terms but less in proportion to generation capacity. The unscrubbed capacity uses more expensive, lower-sulfur fuel.

approach than under a historic or auction approach. Annual NO_x emissions are reduced by more than 40%, and annual SO_2 emissions are reduced by about 46% under the historic and auction approaches. Under the updating approach, the annual NO_x emissions are reduced by more than 65%, and annual SO_2 emissions are reduced by 81% from baseline levels. Mercury emissions are reduced by almost as large of a percentage. In every case, however, national emissions of NO_x, SO_2, and mercury do not change because of emissions caps, so the decrease in emissions inside the RGGI region is offset by an increase outside the region.

The RGGI policy leads to a substantial reduction in the cost of complying with regulations on conventional pollutants. The activities to comply with RGGI lessen the need to install post-combustion controls to reduce emissions of SO_2, NO_x, and mercury. In 2025, the avoided investment in control cost is about $100 million under historic and auction approaches and about $180 million under the updating approach. The use of SO_2, NO_x, and mercury emissions allowances also is reduced. In 2025, emissions reductions lead to savings on emissions allowances of about $80 million under the historic and auction approaches and about $250 million under the updating approach. Total avoided compliance cost with SO_2, NO_x, and mercury rules is about $180 million under the historic and auction approaches and about $436 million under the updating approach.

CO_2 emissions leakage to outside the RGGI region is lowest under an updating approach. In almost all cases, the greatest decrease in CO_2 emissions at the national level occurs with updating. The power generated outside the RGGI region (at plants not subject to the emissions cap) for import into the region increases. However, the incentive to increase generation within the RGGI region under an updating approach offsets this increase somewhat, causing less emissions leakage to outside the region.

In all scenarios, electricity price increases for the rest of nation because of the increased demand for electricity to be imported into the RGGI region. The demand for generation that is not subject to the emissions cap drives up marginal cost in the regions supplying power, which increases prices. Nationally, leakage is lowest and emissions reductions are greatest with the updating approach.

Findings about leakage should be interpreted with caution. We find the percentage of leakage to be sensitive. For example, a small change in natural gas prices due to changes in gas demand in the RGGI region can lead to a small change in the investment profile on the other side of the country in 2025, having a large effect on the leakage calculation for the whole horizon. This effect highlights the importance of modeling institutions that may be put in effect to properly mitigate leakage and to focus on the proper metric.

One may reasonably question whether national forecast changes for 2025 under a RGGI policy have meaning if the rest of the country pursues a business-as-usual policy. Many observers expect other regions of the country or the nation to follow the RGGI example and adopt some form of CO_2 policy. In subsequent analysis, we intend to address these issues to develop a transparent measure of leakage. For this discussion, we focus on cumulative emissions reductions at the national level to identify qualitative relationships among the approaches to distributing allowances.

The social cost of updating is three times that of the other approaches. From a broad social perspective, the change in economic surplus represents the social cost of meeting emissions targets. The change in economic surplus reported in Table 4 is the partial equilibrium measure of social cost within the electricity sector only. Three components of social cost (consumer surplus, producer surplus, and CO_2 revenue) are reported for 2025.

The social costs of the auction and historic approaches are the same, but who bears the cost differs. The auction and historic approaches have almost identical social costs of about $300 million in 2025. The auction imposes a substantial cost on consumers, which is offset by government revenue that can be expected to flow back to households (i.e., to taxpayers) or through other programs. The historic approach imposes a similar burden on consumers, but the revenues from allowance sales flow to producers rather than the government because producers receive the value of the emissions allowances through the allocation mechanism.

The updating approach imposes the least direct cost on consumers because it leads to the smallest increase in electricity price. However, it imposes a cost on producers that is almost as great as under the auction approach, because the lower electricity price means less revenue per unit of electricity generated. The total social cost within the RGGI region electricity sector for the updating approach is $700 million—40% greater than that of the other approaches.

Under the historic and auction approaches, total economic surplus outside the RGGI region increases slightly because of resources allocated to supplying electricity to the RGGI region. However, a sizeable redistribution between consumers and producers occurs. Producers outside the RGGI region that supply power to the RGGI region benefit at the expense of consumers outside the region, who face higher prices. A similar pattern in the allocation of surplus changes between consumers and producers outside the RGGI region occurs under updating, but the net effect is a decrease in total surplus.

In the aggregate, producers realize the lowest value of existing generation assets under updating. Table 5 summarizes the change in the NPV of generation assets in the baseline scenario and the change in value under each approach. It differs from the change in producer surplus reported in Table 4, which is a snapshot for just 2025.

The effect of allocation on asset values varies significantly across types of generators. Table 5 indicates that the aggregate of existing and new gas-fired generation generally gains value relative to the baseline under historic and updating approaches and slightly loses value under an auction approach. Under all approaches, the asset value of gas-fired generation that was in existence as of 1999 increases. The aggregate of existing and additional gas capacity increases in asset value under historic and updating approaches and declines slightly under an auction approach.

Note that Table 5 indicates a negative value for gas-fired assets in the baseline. This measure includes a rental cost of capital for payment on capital investments. In cases where investments have proven uneconomic, the calculation of asset value is negative. Facilities generally continue to operate because revenues remain greater than going-forward variable costs. In some cases, debt service has been written down for accounting purposes, and our baseline measure therefore would not correspond to an accounting measure. However, this practice does not have a bearing on our calculation of the change in asset value from baseline under various policy scenarios.

No new coal-fired or nuclear generating capacity is built in the RGGI region, so the change in asset value for these technologies applies only to existing assets. Coal-fired generation assets just break even under the historic approach and do the worst under updating, losing substantial value relative to the baseline scenario. Existing nuclear assets benefit substantially under a historic or auction approach compared with the baseline. However, nuclear assets lose value under the updating approach, which has a lower electricity price than under historic and auction approaches and leads to lower variable costs for gas units that qualify for allowances, thereby pushing some incremental nuclear generation out of the dispatch order. In variations of updating discussed below, we find that nuclear units do substantially better when they qualify for emissions allowances.

When all types of assets are aggregated, the NPV of generation assets increases substantially under historic allocation and decreases slightly under an auction. The fact that the market value of industry assets is minimally affected under the auction approach may appear to be a paradox but can result from several factors: the long-lived nature of capital investments, the distribution of capital intensity, emissions intensity and fuel intensity of different technologies for generating electricity, and variation in electricity demand by time of day. Meanwhile, in the aggregate, the value of generation assets under the updating approach declines by more than three times the decline under an auction.

In Maryland and the part of Pennsylvania that together constitute the portion of the MAAC region of NERC outside the RGGI region, the change in the NPV of generation is

positive for all types of assets. This result follows from the increased sales supplied to the RGGI region and from the increase in electricity price that applies to every unit of production, including that delivered to native customers outside of the RGGI region.

Figure 2 illustrates the change in the value of generation assets under various approaches, including the bookend approaches and variations discussed in the following sections. The technologies listed include nuclear and coal, for which are composed of only existing plants since all the plants are existing because no new plants are built, and gas, for which plants are both existing and new. The overall generation technologies for the industry also are represented (as All). The three bookend cases discussed previously are indicated by the labels: Heg (historic), Auction, and Demit (updating). Labels at the bottom of the graph correspond to the scenario and the general type of approach; to identify precise mappings, compare the labels on the specific points with the scenarios listed in Table 1.

Even before discussing the variations on the bookend approaches in detail, Figure 2 allows several general observations. Nuclear assets almost always gain value under RGGI. The one exception is the bookend updating case in which natural gas generation expands and there is little change in electricity price. However, in the cases in which nuclear generation earns an allocation, it does substantially better, as indicated by the peaks in its line graph.

Gas-fired generation assets always maintain and sometimes gain value. The only exception is under the auction approach, in which gas loses value slightly. Meanwhile, the only time coal-fired generation assets do not lose substantial value is under the historic approaches and the mixed approaches that combine historic allocation with an auction. Under a couple of the historic approaches, existing coal-fired plants actually gain value because of the generous allowance allocation.

In the aggregate, the change in value for the industry is a weighted average of changes in the value of individual plants. Hence, although some technologies and some firms may gain or lose substantial value, the change in value for the industry is muted because winners offset losers. The industry does the worst under the bookend updating approach, but in the aggregate, the industry experiences little change in value under most non-bookend updating approaches and the auction approach. However, in the aggregate, the industry gains substantial value under the historic approach. The following sections provide more details on the variations in allocation approaches that were modeled.

4. Variations in Results for Historic Approach

Two variations to the bookend historic approach are described in Tables 6–8. The bookend distributes allowances to emitters on the basis of historic generation. One variation distributes allowances to emitters on the basis of historic emissions; another distributes allowances to all generators on the basis of historic generation.

Price and generation differ little among these variations on the historic approach. The overview of electricity price, generation, and emissions in Table 6 shows the main difference: Cumulative national CO_2 emissions are much higher under the scenario in which allowances are distributed to all generators on the basis of generation.

The differences that emerge among the historic approaches are largely due to the characterization of stranded asset recovery policies in the model. The term *stranded assets* describes generation assets that lost value as a result of electricity industry restructuring. We assume that 90% of stranded assets (and 0% of stranded benefits) are recovered through a surcharge on electricity price that is expected to continue for 10 years after the transition from regulation to competition. We assume the award of emissions allowances is considered in calculating the value of existing assets, so the surcharge is adjusted, leading to very slight changes in electricity price. When the model is exercised without stranded asset recovery, the historic approaches solve to exactly the same outcome with respect to electricity price and other measures listed in Table 6.

The market values of various types of assets differ widely under the various approaches to historic allocation. Table 7 indicates there is very little difference in the social cost of the historic approaches or the distribution in cost between consumers and producers. However, Table 8 indicates that one can expect a difference in the incidence of the program among producers, depending on their portfolio of generation assets. Coal-fired generators within the RGGI region are significantly better off when they are allocated permits on the basis of emissions because their share of total emissions is higher than their share of total generation. Additionally, nuclear generators are much better off when permits are distributed to all generators on the basis of historic generation.

5. Variations in Results for Updating Approach

Several variations to the updating approach are reported in Tables 9–11. In the bookend approach, allowances are distributed to emitters on the basis of generation two years previous. Variations that are reported include distribution to all generators and separately adding the eligibility of incremental nonemitters, which include renewable and nuclear generation in excess

of 1999 levels. Another variation adds updating to emitters on the basis of heat input, with an additional factor favoring coal.

In another variation, allowances are distributed only to nonemitters (renewable and incremental nuclear generation), including nonemitters located anywhere in the nation; this variation can be viewed as a type of offset program that might reduce leakage. Finally, in another variation, only nonemitters within the RGGI region qualify. Both of these last two approaches provide incentives to expand generation from nonemitters, somewhat analogous to an RPS. Recall that all renewables in the MAAC region of NERC are always included as part of RGGI when we characterize qualifying renewable generation. We also include incremental nuclear generation in the nonemitters category.

Most of the variations on updating maintain lower increases in electricity price than other approaches. Electricity price increases are small when emitters receive some share of the allocation through updating. The two updating approaches with distribution only to nonemitters yield greater increases than do historic and auction approaches.

CO_2 allowance prices remain relatively high in most of the updating approaches. Total generation in the RGGI region is relatively high except when only nonemitters qualify. Total generation is highest of any approach examined when allocation is on the basis of heat input. The price of a CO_2 allowance is high in the updating runs whenever electricity generation is relatively high because the allowances have a greater opportunity cost. The allowance price is highest when allowances are allocated on the basis of heat input because the allocation provides an incentive for coal-fired generation, which has a greater emissions rate and hence raises the opportunity cost of emissions allowances. The allowance price is lower—comparable to that under auction and historic approaches—when only nonemitters qualify.

It is noteworthy that electricity price in the rest of the nation actually falls below baseline levels when nonemitters nationwide qualify for allowances. Cumulative emissions reductions at the national level are relatively high in this case.

Updating distribution to all generators imposes the lowest social cost within the RGGI region of any policy examined. The economic surplus cost of the program varies among these approaches to updating and in some cases is substantially less than in the bookend case. Distribution to all generators reduces social cost because it reduces each generator's share of allowances and therefore the value of the output subsidy that is awarded to changes in electricity generation. Although the change in social cost is very small within the RGGI region, additional social cost is imposed outside the region.

The dynamic bookend approach was run with an allocation to demand conservation investments, but the results were not sufficiently different to warrant further investigation.

Within the RGGI region, distribution to nonemitters imposes large costs, whereas outside the region, benefits accrue as a result of subsidized investments.

Updating affects different technologies in different ways. In general, these effects depend directly on whether a technology qualifies for distribution and on the value of the allowances in each case. The larger the number of kilowatt-hours generated that qualify for a share of the allowances, the lower the value to each individual facility. It is noteworthy that compared with the bookend approach, distribution to generators—including incremental generation by nonemitters—improves the value of every class of generation asset. We observe that

- the NPV of gas-fired generation does relatively well in most updating approaches,
- the NPV of coal-fired generation suffers under all updating approaches, and
- the NPV of nuclear generation benefits substantially whenever it qualifies for a share of allowances under updating and suffers otherwise, because there is little change in electricity price and the expansion in gas-fired generation crowds out some incremental nuclear generation.

6. Mixed Approaches

Several scenarios in which allowances are distributed through a combination of approaches are described in Tables 12–14. In the overview of changes in electricity price, generation, and emissions, the outcome is roughly a combination of the performance of each individual approach. One way this is not true is with respect to the CO_2 allowance price, which tends toward the price for the auction bookend when the auction is combined with updating. The scenarios that combine an auction with dynamic allocation result in more emissions reductions at the national level than the scenarios that combine an auction with historic allocation.

Changes in economic surplus measures for the combination of an auction with an updating approach are between those for the auction bookend and the updating bookend approaches. The economic cost for consumers is less than for the auction bookend, and like the auction, the cost to consumers is less than the gain in government revenues. Similarly, in the mixed auction–historic approach, as with each approach taken individually, producers outside the RGGI region benefit considerably from the opportunity to supply power at a higher electricity price to consumers in the RGGI region. Modifying the combined auction–historic case to compensate coal-fired generators more than gas-fired generators per kilowatt-hour of historic generation has no effect on the economic surplus costs of that mixed allocation approach.

The changes in the components of economic surplus under the various mixed approaches are compared with the other scenarios in Figure 3 for 2025. Changes in consumer surplus, producer surplus, CO_2 revenue, and total surplus are plotted. The policy scenarios are ordered in terms of the size of their associated CO_2 auction revenues and are grouped by general category of approach (updating, historic, mixed, or auction).

Figure 3 shows that all the mixed scenarios produce revenues for the government that can be used for compensation or other purposes. The mixed scenarios that include historic allocation tend to substantially reduce gains to producers found under the pure historic approaches without imposing substantial costs in terms of total surplus losses or greater losses in consumer surplus than under the pure historic or the pure auction approach. Combining updating and auction approaches in equal proportions has a bigger adverse effect on consumers in the form of higher electricity prices than a pure updating approach that rewards incremental generation by nonemitters. All of the mixed approaches have very similar effects on total economic surplus but distinguish themselves in terms of effects on the different components of surplus.

The increase in asset values for gas-fired generation in the mixed auction–updating approaches is close to that for the auction bookend, which is less than that for the updating bookend. The increase is slightly less when coal-fired generators earn twice as many allowances as gas-fired generators per kilowatt-hour of generation. The decrease in value for coal-fired generation is worse than for the auction approach but not as bad as under updating. The mixed auction–historic approach reduces the losses to coal-fired generators compared to the auction approach, especially when coal-fired generators earn twice as many allowances as gas-fired generators do per unit of historic generation. Nuclear generation benefits in the mixed approach cases because the increases in electricity price are greater than under updating. For the industry as a whole, the change in asset values is small in the aggregate because the mixed approaches yield greater increases in electricity price than the updating bookend does. Increasing the fraction of allowances that are auctioned while updating the remaining allowances generally has a positive impact on the asset values of all types of generators, including coal-fired generators. The one exception is that moving from a 50% auction–50% updating approach to a 100% auction approach has a negative effect on the asset value of gas-fired generators in the RGGI region.

The mixed auction–historic approaches have a positive effect on average asset values across the industry and produce a much smaller drop in the value of coal-fired generation assets than the mixed auction–updating approaches. Interestingly, the increase in average asset values for existing units in the RGGI region under the auction–historic approach based on generation is the roughly the same as that for generators outside the RGGI region. In the RGGI region, these assets experience the program costs and receive a share of allowance allocation that is

approximately equal, resulting in a financial situation similar to that of assets outside the RGGI region.

7. Constrained Cases

Several constraints in the electricity system affect the operation of individual facilities and the adjustment in prices in ways that are not fully represented in the model. Many are short-run constraints, such as fuel supply contracts that would be renegotiated over time. Others, such as requirements to balance load on the grid, affect individual facilities but are not expected to have a noticeable effect on the behavior of the entire system. However, two types of constraints in the Northeast seem to be potentially important in the long run: the ability to supply natural gas to the Northeast, and the capability of the transmission grid to deliver power.

If natural gas is an important component of achieving compliance with RGGI, then changes in gas prices or demand could be important. To address this issue, we ran a scenario in which gas prices at the national level were 15% above baseline levels. In addition, any increase in Northeast gas demand above baseline levels in 2008 resulted in a regional change in price that was twice as sensitive as in the baseline scenario.

Our findings from the standard baseline are repeated in the first columns in Tables 15 and 17, and in the second column of Table 16. The second columns of Tables 15 and 17 consider the historic bookend approach with higher gas prices. The differences in electricity prices and the choice of generation technology are substantial, largely because of the change in natural gas prices that we assume occurs independent of changes in gas demand as a result of the RGGI program. Another result is interesting, nonetheless: The NPV of all technologies is substantially higher in the constrained gas case than in the baseline scenario (Table 17). This finding follows from the increase in the cost of natural gas–fired generation, which is the technology that determines marginal electricity price in most time blocks. Hence, a higher gas price translates into a higher electricity price, and the change in revenue generally is greater than the change in cost for the industry.

A second potentially important constraint is transmission capability. In the baseline model inter-regional transmission capability is represented by quantity constraints. In the constrained transmission model, inter-regional transmission capability is also constrained by additional prices, cost thresholds, and line losses. Intra-regional line losses also are represented on average. Intra-regional quantity constraints are not captured directly, but some of the implications of those constraints are represented. For example, the model is calibrated to achieve what would otherwise appear to be out-of-merit-order dispatch of oil-fired facilities, which tend

to run because of the limitations to transmission into the New York metropolitan area and the difficulty of siting new sources in the area.

The first column under "Constrained baseline" in Tables 15–17 is a new baseline that includes both the natural gas constraint described above and a 10% reduction in inter-regional transmission capability; the subsequent column describes the historic bookend under these constraints.

The effect of adding constraints on natural gas supply and electricity transmission capability is larger than the effect of adding the RGGI policy. The constraints cause substantial changes in the absence of the RGGI policy (evident from a comparison of the first and third columns of Table 15). Moreover, the changes in electricity price and other overview measures that occur as a result of adding the RGGI policy to the constrained no-policy baseline (third and fourth columns of Table 15) are comparable to those that occur when the policy is added to the central case baseline (Table 3). Also, the constraint on natural gas price is more important than the constraint on inter-regional transmission capability (Table 15). The model with both constraints varies little compared with the model with only high gas price.

Producers benefit substantially in the face of constraints on natural gas price or transmission capability. Table 16 presents the change in economic surplus reported as the difference from the central case baseline. The higher gas price negatively affects consumers and benefits producers. Again, the change in surplus due to adding the constraints in the absence of the policy tends to be larger than the change due to adding the policy.

The value of every type of generation asset in the RGGI region improves with the additional constraints, and the value of every type of asset improves further with the implementation of the policy. Even the value of natural gas–fired generation assets improves with the constraint of higher gas prices.

The modeled constraints do not appear to have a strong impact on RGGI implementation. Overall, the changes in electricity price, technology choices for electricity generation, and the cost distribution due to implementation of the RGGI policy do not vary substantially in the presence of constraints on natural gas supply or transmission capability in the way we have modeled them. In the historic, auction, and many updating approaches, an expansion of natural gas–fired generation does not play a significant role in compliance. Hence, changes in the cost of natural gas will affect the baseline and the policy scenario equally. Incorporating transmission rules aimed at reducing leakage could play a big role, but that modeling is left to future research.

8. Renewable Portfolio Standard Cases

Our standard base case and policy scenarios do not include all of the state-level policies to promote renewables used in the RGGI states. To get a sense of how policies to encourage renewables might affect the results of a RGGI policy, we ran a baseline scenario against one policy case with an aggregate regional RPS. These results are presented in Tables 18–20.

The RPS policy scenario we developed is intended to reasonably reflect all of the existing renewables policies for states in the three NERC regions covered or partially covered by RGGI (i.e., the New England states, New York, and the MAAC NERC region). It is not intended to be an exact representation of RPS policies in the included states but a plausible approximation of existing policies that probably represents a slightly higher level of renewables requirements than embodied in current policy because of rounding. The policy is specified as mandated increments to existing non-hydro renewable generation of 4.4%, 9.5%, 11.5%, and 12.6% in 2008, 2015, 2020, and 2025, respectively. It also includes increased imports from Canada to New York that are largely expected to come from hydro generation.

In an RPS baseline (e.g., in the absence of the RGGI policy), renewable generation increases by 67% relative to the standard baseline within the three NERC regions by 2025, whereas electricity price remains roughly the same and CO_2 emissions decrease 9%, by 14 million tons. The increase in renewable generation mostly replaces gas-fired generation because coal-fired generation remains nearly the same and gas-fired generation declines by 18%. The price of a renewable credit is $16/MWh in 2025.

We model the addition of the RGGI policy by assuming CO_2 allowances are distributed to emitters on the basis of historic generation, in a scenario analogous to the bookend historic approach. The RPS policy by itself is much more potent than the RGGI policy by itself with respect to generation by renewables (Table 18). The big difference between these policy scenarios is the effect on technology: The increased renewable generation displaces gas-fired generation under the RPS policy, whereas coal-fired generation declines by more than gas-fired generation under the RGGI policy.

When the RGGI policy is combined with the RPS baseline, the level of generation by coal is intermediate—above the level with just the RGGI policy and below the level with just the RPS. However, gas-fired generation declines even more than under just the RPS policy, to 75% of the standard baseline and 91% of the RPS baseline. The price of electricity in the RGGI region rises to $106/MWh (an increase of $2.70/MWh from the RPS baseline), causing generation within the RGGI region to fall by 37 billion kWh below the RPS baseline. However, electricity price in 2025 with the RPS and the RGGI policy is $1.1/MWh lower than with the RGGI policy

alone. The electricity price is lower because the RPS encourages generation by renewables, which have lower variable costs and thus exert downward pressure on electricity price.

Having an RPS in place lowers baseline CO_2 emissions and thus the cost of CO_2 allowances. The CO_2 allowance price in 2025 is $15.6/ton, about $2.50/ton less than without the RPS. The incentive for renewable generation clearly makes compliance with the regional CO_2 cap easier. The price of a renewable credit is $12/MWh in 2025 with the RGGI policy. Total renewable generation is slightly less than under just the RPS policy because total generation in the region is lower; the share of total generation made up by renewables remains equal to the RPS policy target.

The economic cost of the policies is reported in Table 19. In the baseline scenario with RPS, the consumer surplus within the RGGI region is approximately the same as under the baseline alone, but producers are better off than under the standard baseline, at the expense of consumers outside the region. When the RGGI policy is added, the cost to consumers in the RGGI region is offset by an almost equal benefit to producers, with no net change in economic surplus from the standard baseline. Consumers are worse off because of the increase in electricity price. Compared with the bookend historic approach without the RPS, consumers in the RGGI region are substantially better off and producers are slightly better off. Nationally, the economic surplus results are similar to those in the RPS baseline. In both the RPS baseline and the combined RPS–RGGI policy cases, additional costs stem from the tax credits offered by the federal government and realized because of the expanded generation by renewables. This cost is not shown as a separate item but is evident in the subtotals and the national total in Table 19.

The asset values of various types of generation are affected differently by the RPS and CO_2 cap (Table 20). Within the RGGI region under the RPS policy, gas-fired and nuclear generation decline slightly in value, whereas coal-fired generation remains the same. Meanwhile, renewable generation increases substantially in value (not reported in the table). Outside the RGGI region but in the MAAC NERC region, the value of gas-fired generation increases modestly. Adding the CO_2 cap causes the value of gas-fired and nuclear generation to increase within the RGGI region relative to the standard baseline, whereas coal-fired generation loses value. The effects on asset values of the RGGI policy with historic allocation are usually smaller in the presence of the RPS than in the bookend case.

9. Conclusion

In this research, we model historic, auction, and updating approaches to the allocation of emissions allowances that we call bookends, then model several variations on these approaches.

We find that how allowances are initially allocated has a substantial effect on electricity price and consumption, the mix of technologies used to generate electricity, the emissions levels of conventional pollutants, and the cost of controlling the emissions of conventional pollutants.

The value of CO_2 allowances created by the RGGI program is at least four times the social cost of mitigation. The fact that changes in electricity price depend on how emissions allowances are initially distributed suggests that allowance distribution offers a potentially important source of compensation. We assess the effects of different distribution approaches on the change in the market value of generation assets and find substantial variation depending on the method of allocation.

The measure of compensation that is required to preserve asset value varies according to whether it is calculated at the level of the facility, business unit, firm, or state. Change in shareholder value depends on the portfolio of assets held by the firm. We do not calculate the change in value at the firm level in this paper, but policymakers may be interested in this information when considering how different parties are affected.

A general pattern emerges from our modeling results of allocation approaches: A historic or auction approach is most efficient. The updating approach has about three times the social cost of the historic or the auction approach but has the political advantage of a lower electricity price and can be designed to reduce leakage.

Recognizing that updating has attracted interest in the RGGI process, we explore several variations on the updating approach, with various consequences. It is noteworthy that one variation—updating allocation on the basis of all generation—has the lowest social cost within the RGGI region of any approach we modeled, partly because it imposes costs outside the region. Ultimately, however, updating has less attraction as a model for a national (or international) policy because of its higher social cost, and because of the difficulty in establishing a consistent allocation method across different sectors of the economy. Hence, we suggest that updating may be a useful tool for the initial implementation of RGGI but not at the national level.

The approaches vary significantly in their aggregate effects on asset values and specific types of generation technology. The industry benefits most with the historic approach, and consumers benefit least. The auction approach is the intermediate case with respect to the effect on market value, and the updating approach leads to the greatest aggregate decline in market value for the industry.

The auction approach that we model might be implemented in various forms. One is allocation to consumers, or a public benefit allocation, which endows a trustee with allowances that can be sold to the industry with the revenue applied to a variety of purposes. Some observers

have suggested that investments in energy conservation or renewables research could be funded through this kind of approach.

Important limitations to these results stem from the level of aggregation used in the analysis. Intra-regional transmission constraints are not modeled. Electricity imports from Canada are parametric and do not change in response to the RGGI policy, which could affect the amount of emissions leakage that occurs. Out-of-merit-order dispatch that may result from long-term fuel contracts or intra-regional transmission constraints is approximated based on evidence from recent years. We conduct sensitivity analyses with constraints on natural gas prices and transmission capability and find that the social cost of the RGGI program does not appear to be sensitive to these constraints.

The variation that we discover in the measures and the performance of various policies suggests that policymakers have latitude in providing compensation to industry through the distribution of emissions allowances. We suggest that greater emphasis could be placed on compensation in the short run and on efficiency in the long run and indicate what some types of mixes in approaches to allocation would accomplish. In the long run, on the national stage, a CO_2 cap-and-trade policy could impose significant costs on the economy. Hence, we suggest that efficiency concerns should be a central consideration in the long-run policy design.

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Tables

Table 1. Modeled Scenarios

Approach		*Eligibility*	*Basis for Allocation*
Historic			
Heg	a. (Bookend)	Emitters	Historic generation
Hag	b.	Generators	Historic generation
Hee	c.	Emitters	Historic emissions
Auction			
Auc	d. (Bookend)	Emitters	Auction
Updating			
Demit	e. (Bookend)	Emitters	Recent generation
Dag	f.	Generators	Recent generation
Dagig	g.	Generators	Generation (emitters) or incremental generation (nonemitters)
Dn3ig	h.	Nonemitters	Incremental generation for nonemitters
DnNig	i.	Nonemitters nationwide	Incremental generation for nonemitters
Dehi	j	Emitters	Recent heat input with factor favoring coal
Mixed			
MAHeg	k.	Historic (a) (50%) / Auction (d) (50%)	Historic generation / Auction
MADagig	m.	Auction (d) (50%) / Updating (e) (50%)	Auction / Recent generation
MA20Dagig	n.	Auction (d) (20%) / Updating (e) (80%)	Auction / Recent generation
MaHee	o.	Historic (a) (50%) / Auction (d) (50%)	Historic emissions / Auction
MAHeg_coal	p.	Historic (a) (50%) / Auction (d) (50%)	Historic emissions / Auction; coal-fired generation counts double
MADeg_coal	q.	Auction (d) (50%) / Updating (e) (50%)	Auction / Recent generation; coal-fired generation counts double
Constrained			
HegGhi	r. Higher gas price	Emitters (Historic a)	Historic generation
HegT10Ghi	s. Constraints[a]	Emitters (Historic a)	Historic generation

[a] New baseline: constrained transmission capability (assuming interregional capability in the Northeast reduced by 10%) and higher gas price.

Notes: Historic generation and historic emissions = 1999. Recent generation is based on two years previous to allocation. Incremental generation includes generation beyond 1999 levels. Higher gas price has national (Henry Hub) prices pegged 15% above baseline and supply price sensitivity scenarios for imports into the Northeast above baseline levels doubled.

Table 2. National Annual Baseline Emissions and Annual Policy Emissions Targets

Pollutant	*2008*	*2015*	*2020*	*2025*
Nationwide				
CO_2 (million tons)	2,755	2,910	3,102	3,311
NO_x (thousand tons)	3,891	2,551	2,615	2,670
SO_2 (thousand tons)	7,181	4,963	4,293	3,178
Mercury (tons)[a]	62	40	38	36
RGGI region				
CO_2 (million tons)	124	129	136	147
NO_x (thousand tons)	106	111	117	118
SO_2 (thousand tons)	415	238	196	193
Mercury (tons)[a]	1.7	1.2	1.2	1.2
Reduction target				
CO_2 (million tons)	124	114	107	100

[a] Includes mercury emissions from uncontrolled municipal solid waste facilities that in fact have already begun to achieve important emissions reductions.

Table 3. Overview for Bookend Cases, 2025

Eligibility:		*Emitters*	*Emitters*	*Emitters*
Basis:		*Historic generation*	*Auction*	*Recent generation*
RGGI region	Baseline	Historic	Auction	Updating
Average electricity price (1999$/MWh)	$103.4	$107.1	$107.2	$103.9
TOTAL generation (billion kWh)	393	348	348	371
Coal	73	48	48	23
Gas	130	115	116	173
Nuclear	107	108	108	106
Renewable	34	40	40	32
TOTAL new capacity[a] (GW)	28	31	31	33
Gas	23	24	24	28
Renewable	5	6	6	5
CO_2 price (1999$/ton)	n/a	$18.1	$18.3	$35.3
Emissions				
CO_2 (million tons)	147	100	99	98
NO_x (thousand tons)	118	70	70	41
SO_2 (thousand tons)	193	101	107	36
Mercury (tons)	1.2	0.8	0.8	0.3
Rest of nation[b]				
Average electricity price (1999$/MWh)	$66.6	$66.8	$66.8	$66.9
TOTAL generation (billion kWh)	4,847	4,885	4,886	4,861
CO_2 reduction for nation cumulative (2008–2025) (million tons)	n/a	201	233	289
Model	BL	Heg	Auc	Demit

[a] Numbers may not sum because of rounding.

[b] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 4. Change in Economic Surplus from Baseline (Social Cost), Bookend Cases, 2025 (billion 1999$)

Eligibility:	*Emitters*	*Emitters*	*Emitters*
Basis:	*Historic generation*	*Auction*	*Recent generation*
RGGI region	Historic	Auction	Updating
Consumers	–1.6	–1.6	–0.2
Producers	1.2	–0.6	–0.5
CO_2 revenue	0.0	1.8	0.0
SUBTOTAL[a]	–0.5	–0.5	–0.7
Rest of nation[b]			
Consumers	–1.2	–1.2	–1.3
Producers	1.5	1.5	1.2
SUBTOTAL[a]	0.2	0.2	–0.2
National TOTAL[a]	–0.3	–0.3	–0.9
Model	Heg	Auc	Demit

[a] Numbers may not add because of other categories including change in tax credit costs.

[b]Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 5. NPV of Existing and New Generation Assets, Change from Baseline, Bookend Cases (1999$/kW)

Eligibility:		*Emitters*	*Emitters*	*Emitters*
Basis:		*Historic generation*	*Auction*	*Recent generation*
RGGI region	Baseline (NPV)	Historic	Auction	Updating
Gas	–273	54	–13	45
Coal	434	8	–185	–240
Nuclear	611	67	55	–51
Average ALL[b]	164	60	–13	–45
Existing capacity only[c]				
Gas	–375	228	17	102
Coal	434	8	–185	–240
Nuclear	611	67	55	–51
Average ALL[b]	300	104	–3	–51
MD and PA[a]				
Gas	–255	6	12	12
Coal	364	50	–185	24
Nuclear	653	51	51	20
Average ALL[b]	229	23	26	8
Model	BL	Heg	Auc	Demit

[a] Maryland and the portion of Pennsylvania within MAAC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

[c] Existing in 1999.

Table 6. Overview of Historic Allocation Cases

Eligibility:	*Emitters*	*Emitters*	*Generators*
Basis:	*Historic generation*	*Historic emissions*	*Historic generation*
RGGI region			
Average electricity price (1999$/MWh)	$107.1	$106.8	$107.5
TOTAL generation (billion kWh)	348	349	348
Coal	48	48	48
Gas	115	116	115
Nuclear	108	108	108
Renewable	40	40	40
New capacity[a] (GW)	31	31	31
Gas	24	24	24
Renewable	6	6	6
CO_2 price (1999$/ton)	$18.1	$18.2	$18.3
Emissions			
CO_2 (million tons)	100	100	100
NO_x (thousand tons)	70	72	71
SO_2 (thousand tons)	101	107	105
Mercury (tons)	0.8	0.8	0.8
Rest of nation[b]			
Average electricity price (1999$/MWh)	$66.8	$66.8	$66.9
TOTAL generation(billion kWh)	4,885	4,886	4,887
CO_2 reduction for nation cumulative (2008–2025) (million tons)	201	219	249
Model	Heg	Hee	Hag

[a]Numbers may not sum because of rounding.

[b]Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 7. Change in Economic Surplus from Baseline (Social Cost), Historic Cases, 2025 (billion 1999$)

Eligibility:	*Emitters*	*Emitters*	*Generators*
Basis:	*Historic generation*	*Historic emissions*	*Historic generation*
RGGI region			
Consumers	–1.6	–1.4	–1.7
Producers	1.2	1.0	1.3
CO_2 revenue	0.0	0.0	0.0
SUBTOTAL[a]	–0.5	–0.5	–0.5
Rest of nation[b]			
Consumers	–1.2	–1.1	–1.3
Producers	1.5	1.3	1.4
SUBTOTAL[a]	0.2	0.1	–0.1
National TOTAL[a]	–0.3	–0.4	–0.6
Model	Heg	Hee	Hag

[a]Numbers may not add because of other categories including change in tax credit costs.

[b]Includes the MAAC region of NERC outside the RGGI region.

Table 8. Change from Baseline of Net Present Value of Generation Assets, Historic Cases (1999$/kw)

Eligibility:	*Emitters*	*Emitters*	*Generators*
Basis:	*Historic generation*	*Historic emissions*	*Historic generation*
RGGI region			
Gas	54	19	33
Coal	8	34	–61
Nuclear	67	48	169
Average ALL[b]	60	36	68
MD and PA[a]			
Gas	6	2	23
Coal	50	55	46
Nuclear	51	51	48
Average ALL[b]	23	23	24
Model	Heg	Hee	Hag

[a]Maryland and portion of Pennsylvania within the MAAC region of NERC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

Table 9. Overview for Updating Allocation Based on Generation, 2025

Eligibility:	*Emitters*	*Generators*	*Generators*	*Nationwide nonemitters*	*Nonemitters in NY, NE, & MAAC*	*Emitters*
Basis:	*Recent generation*	*Recent generation*	*Recent generation (emitters), incremental generation (nonemitters)*	*Recemt incremental generation*	*Recent incremental generation*	*Recent heat input with add'l factor favoring coal*
RGGI region						
Average electricity price (1999$/MWh)	$103.9	$104.0	$103.9	$107.0	$106.5	$103.8
TOTAL generation (billion kWh)	371	374	367	350	356	376
Coal	23	43	39	48	52	22
Gas	173	129	137	114	104	169
Nuclear	106	108	107	108	108	107
Renewable	32	58	46	43	55	38
New capacity[a] (GW)	33	35	33	32	34	32
Gas	28	25	25	24	23	26
Renewable	5	10	8	7	11	6
CO_2 price (1999$/ton)	$35.3	$23.7	$26.1	$18.1	$16.4	$45.9
Emissions						
CO_2 (million tons)	98	100	100	100	100	100
NO_x (thousand tons)	41	65	63	69	73	51
SO_2 (thousand tons)	36	82	65	104	115	34
Mercury (tons)	0.3	0.7	0.6	0.8	0.8	0.4
Rest of nation[b]						
Average electricity price (1999$/MWh)	$66.9	$66.7	$66.7	$66.5	$66.8	$66.8
TOTAL generation (billion kWh)	4,861	4,862	4,870	4,888	4,878	4,860
CO_2 reduction nation, 2008–2025 (million tons)	289	232	282	461	310	204
Model	Demit	Dag	Dagig	DnNig	Dn3ig	DEhi

Table 10. Change in Economic Surplus from Baseline (Social Cost) for Updating Cases, 2025 (billion 1999$)

Eligibility:	*Emitters*	*Generators*	*Generators*	*Nationwide nonemitters*	*Nonemitters in NY, NE, & MAAC*	*Emitters*
Basis:	*Recent generation*	*Recent generation*	*Generation (emitters), incremental generation (nonemitters)*	*Incremental generation*	*Incremental generation*	*Recent heat input with add'l factor favoring coal*
RGGI region						
Consumers	–0.2	–0.2	–0.2	–1.5	–1.3	–0.2
Producers	–0.5	0.1	–0.1	–0.5	0.4	–0.6
CO_2 revenue	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL[a]	–0.7	–0.2	–0.4	–2.1	–1.2	–0.8
Rest of nation[b]						
Consumers	–1.3	–0.6	–0.6	0.3	–0.9	–0.8
Producers	1.2	0.3	0.6	1.5	1.6	0.4
SUBTOTAL[a]	–0.2	–0.3	–0.1	1.3	0.5	–0.4
National TOTAL[a]	–0.9	–0.5	–0.6	–0.8	–0.6	–1.3
Model	Demit	Dag	Dagig	DnNig	Dn3ig	DEhi

[a]Numbers may not add because of other categories including change in tax credit costs.

[b]Includes the MAAC region of NERC outside the RGGI region.

Table 11. Change from Baseline in Net Present Value of Generation Assets, Updating Cases (1999 $/kW)

Eligibility:	*Emitters*	*Generators*	*Generators*	*Nationwide nonemitters*	*Nonemitters in NY, NE, & MAAC*	*Emitters*
Basis:	*Recent generation*	*Recent generation*	*Generation (emitters), incremental generation (nonemitters)*	*Recent incremental generation*	*Recent incremental generation*	*Recent heat input with add'l factor favoring coal*
RGGI region						
Gas	45	–2	16	7	–3	–1
Coal	–240	–231	–223	–159	–175	–235
Nuclear	–51	136	53	93	147	–21
Average ALL	–45	5	–1	20	30	–57
MD and PA[a]						
Gas	12	–5	10	23	21	22
Coal	24	35	43	50	48	31
Nuclear	20	35	37	65	129	25
Average ALL[b]	8	9	14	30	47	13
Model	Demit	Dag	Dagig	DnNig	Dn3ig	Dehi

[a]Maryland and portion of Pennsylvania within the MAAC region of NERC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

Table 12. Overview for Mixed Approaches

Eligibility:	*Generators*	*Generators*	*Emitters*	*Emitters*	*Emitters*	*Emitters*
Basis:	*Auction 20%/ Recent gen. 80%*	*Auction 50%/ Recent gen. 50%*	*Auction 50%/ Historic gen. 50%*	*Auction 50%/ Historic emissions 50%*	*Auction 50%/ Historic gen. 50%*[a]	*Auction 50%/ Recent gen. 50%*[a]
RGGI region						
Average electricity price (1999$/MWh)	$103.9	$105.5	$107.5	$107.1	$107.5	$105.5
TOTAL generation (billion kWh)	359	354	348	349	348	356
Coal	43	45	48	48	48	42
Gas	130	121	115	115	116	130
Nuclear	108	108	108	108	108	108
Renewable	42	42	40	40	40	40
New capacity[b] (GW)	32	32	31	31	31	32
Gas	25	25	25	24	24	25
Renewable	7	7	6	6	6	6
CO_2 price (1999$/ton)	$24.4	$21.8	$18.3	$18.2	$18.4	$23.8
Emissions						
CO_2 (million tons)	100	100	99	100	100	99
NO_x (thousand tons)	64	67	69	69	70	61
SO_2 (thousand tons)	83	99	104	103	105	78
Mercury (tons)	0.7	0.8	0.8	0.8	0.8	0.7
Rest of Nation[c]						
Average electricity price (1999$/MWh)	$66.7	$66.8	$66.8	$66.8	$66.8	66.8
TOTAL generation (billion kWh)	4,878	4,882	4,883	4,885	4,882	4,880
CO_2 reduction nation, 2008–2025 (million tons)	283	284	234	190	199	241
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

[a] Coal-fired generation counts twice.

[b] Numbers may not sum because of rounding.

[c] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 13. Change in Economic Surplus from Baseline (Social Cost), Mixed Cases, 2025 (billion 1999$)

Eligibility:	*Generators*	*Generators*	*Emitters*	*Emitters*	*Emitters*	*Emitters*
Basis:	*Auction 20%/ Recent gen. 80%*	*Auction 50%/ Recent gen. 50%*	*Auction 50%/ Historic gen. 50%*	*Auction 50%/ Historic emissions 50%*	*Auction 50%/ Historic emissions 50%*[a]	*Auction 50%/ Recent gen. 50%*[a]
RGGI region						
Consumers	–0.2	–0.9	–1.8	–1.6	–1.8	–0.9
Producers	–0.7	–0.6	0.3	0.2	0.3	–1.0
CO_2 revenue	0.5	1.1	0.9	0.9	0.9	1.4
SUBTOTAL[b]	–0.5	–0.5	–0.6	–0.5	–0.6	–0.5
Rest of nation[c]						
Consumers	–0.7	–0.9	–1.1	–1.0	–1.0	–1.2
Producers	0.6	0.8	1.4	1.2	1.4	1.3
SUBTOTAL[b]	–0.1	–0.1	0.2	0.2	0.3	0.0
National TOTAL[b]	–0.6	–0.6	–0.4	–0.3	–0.3	–0.5
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

[a] Coal -fired generation counts twice.

[b] Numbers may not sum because of other categories including change in tax credit costs.

[c] Includes the MAAC region of NERC outside the RGGI region.

Table 14. Change in Net Present Value of Generation Assets from Baseline, Mixed Cases (1999 $/kW)

Eligibility:	*Generators*	*Generators*	*Emitters*	*Emitters*	*Emitters*	*Emitters*
Basis:	*Auction 20%/ Recent gen. 80%*	*Auction 50%/ Recent gen. 50%*	*Auction 50%/ Historic gen. 50%*	*Auction 50%/ Historic emissions 50%*	*Auction 50%/ Historic emissions 50%*[z]	*Auction 50%/ Recent gen. 50%*[a]
RGGI region						
Gas	7	14	28	5	11	4
Coal	–221	–198	–88	–77	–50	–222
Nuclear	49	51	68	53	62	40
Average ALL[b]	–13	–8	32	14	19	–21
MD and PA[c]						
Gas	–4	14	27	11	21	6
Coal	39	46	54	50	59	59
Nuclear	35	47	56	48	52	55
Average ALL[b]	14	24	33	23	28	25
Model	MA20Dagig	MADagig	MAHeg	MAHee	MAHeg_coal	MADeg_coal

[a] Coal-fired generation counts twice.

[b] ALL includes all generation capacity including types not listed separately.

[c] Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

Table 15. Overview of Constrained Cases

Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:	*None*	*Higher gas price*	*Higher gas price & transmission limits*	
RGGI region	Standard baseline		Constrained baseline	
Average electricity price (1999$/MWh)	$103.4	$112.2	$108.4	$112.7
TOTAL generation (billion kWh)	393	345	386	347
Coal	73	50	74	49
Gas	130	96	97	97
Nuclear	107	108	108	108
Renewable	34	47	37	47
New capacity[a] (GW)	28	30	28	30
Gas	23	22	22	22
Renewable	5	8	6	8
CO_2 price (1999$/ton)	n/a	$20.6	$0.0	$20.5
Emissions				
CO_2 (million tons)	147	99	149	100
NO_x (thousand tons)	118	76	115	77
SO_2 (thousand tons)	193	127	250	130
Mercury (tons)	1.2	0.8	1.2	0.8
Rest of nation[b]				
Average electricity price (1999$/MWh)	$66.6	$67.5	$67.2	$67.5
TOTAL generation (billion kWh)	4,847	4,867	4,838	4,864
CO_2 reduction for nation cumulative (2008–2025)	n/a	n/a[c]	n/a	238[d]
Model	BL	HegGhi	BLT10Ghi	HegT10Ghi

[a] Numbers may not sum because of rounding.

[b] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

[c] No baseline was run for only high natural gas prices.

[d] Compared with Constrained Baseline.

Table 16. Change in Economic Surplus from Standard Baseline (Social Cost), 2025, Constrained Cases (billion 1999$)

Eligibility:	*Emitters*		*Emitters*
Basis:	*Historic generation*		*Historic generation*
Constraints:	*Higher gas price*	*Higher gas price & electricity transmission limits*	
RGGI region	Standard baseline	Constrained baseline	
Consumers	–3.8	–2.2	–4.0
Producers	2.4	1.0	2.6
CO_2 revenue	0.0	0.0	0.0
SUBTOTAL[a]	–1.5	–1.2	–1.5
Rest of nation[b]			
Consumers	–4.1	–2.4	–4.0
Producers	2.8	0.9	2.9
SUBTOTAL[a]	–1.9	–2.3	–1.7
National TOTAL[a]	–3.4	–3.5	–3.2
Model	HegGhi	BLT10Ghi	HegT10Ghi

[a] Numbers may not add because of other categories including change in tax credit costs.

[b]Includes the MAAC region of NERC outside the RGGI region.

Table 17. Net Present Value of Generation Assets in Baseline, Changes from Standard Baseline for Constrained Cases (1999$/kW)

Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:		*Higher gas price*	*Higher gas price &electricity transmission limits*	
RGGI region	Standard baseline		Constrained baseline	
Gas	–273	47	1	54
Coal	434	147	154	156
Nuclear	611	208	146	206
Average ALL[b]	164	125	76	124
MD and PA[a]				
Gas	–255	–14	–13	–11
Coal	364	161	78	145
Nuclear	653	173	87	157
Average ALL[b]	229	94	47	77
Model	BL	HegGhi	BLT10Ghi	HegT10Ghi

[a] Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

[b] ALL includes all generation capacity including types not listed separately.

Table 18. Overview of RPS Case

Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:	*None*	*None*	*RPS*	*RPS*
RGGI region	Standard baseline		RPS baseline	
Average electricity price (1999$/MWh)	$103.4	$107.1	$103.3	$106.0
TOTAL generation (billion kWh)	393	348	387	350
Coal	73	48	70	55
Gas	130	115	107	97
Nuclear	107	108	107	107
Renewable	34	40	57	54
New capacity[a] (GW)	28	31	31	33
Gas	23	24	21	23
Renewable	5	6	10	9
CO_2 price (1999$/ton)	n/a	$18.1	n/a	$15.6
Emissions				
CO_2 (million tons)	147	100	133	99
NO_x (thousand tons)	118	70	110	76
SO_2 (thousand tons)	193	101	190	120
Mercury (tons)	1.2	0.8	1.2	0.9
Rest of nation[b]				
Average electricity price (1999$/MWh)	$66.6	$66.8	66.7	66.9
TOTAL generation (billion kWh)	4,847	4,885	4,844	4,875
CO_2 reduction for nation cumulative (2008–2025)	n/a	201	n/a	141[c]
Model	BL	Heg	RPS_BL	Heg_RPS

[a] Numbers may not sum because of rounding.

[b] Includes Maryland and portion of Pennsylvania within MAAC outside the RGGI region.

[c] Compared with RPS Baseline.

Table 19. Change in Economic Surplus from Standard Baseline (Social Cost), 2025, RPS Case (billion 1999$)

Eligibility:	*Emitters*		*Emitters*
Basis:	*Historic generation*		*Historic generation*
Constraints:	*None*	*RPS*	*RPS*
RGGI region		RPS Baseline	
Consumers	–1.6	0.0	–1.1
Producers	1.2	0.6	1.3
CO_2 revenue	0.0	0.0	0.0
SUBTOTAL[a]	–0.5	0.5[c]	0.0[c]
Rest of nation[b]			
Consumers	–1.2	–0.7	–1.4
Producers	1.5	0.0	1.1
SUBTOTAL[a]	0.2	–1.4[c]	–1.0[c]
National TOTAL[a]	–0.3	–0.9	–1.0
Model	Heg	RPS_BL	Heg_RPS

[a] Numbers may not add because of other categories including change in tax credit costs.

[b]Includes MAAC outside RGGI.

[c]Subtotal includes cost of federal tax credits.

Table 20. Net Present Value of Generation Assets in Baseline, Changes from Standard Baseline for RPS Case (1999$/kW)

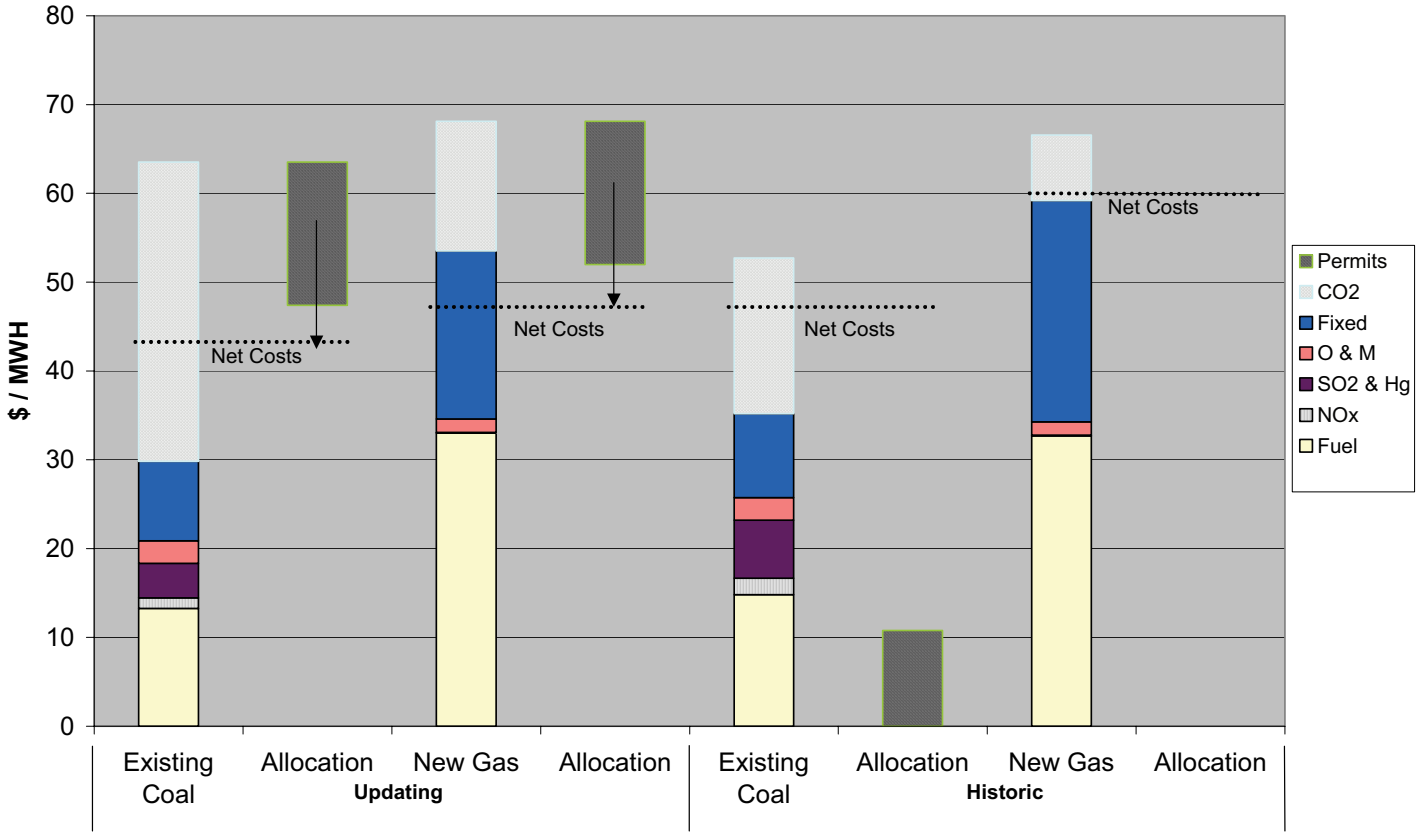
Eligibility:		*Emitters*		*Emitters*
Basis:		*Historic generation*		*Historic generation*
Constraints:	*None*	*None*	*RPS*	*RPS*
RGGI region	Standard baseline		RPS baseline	
Gas	–273	54	–18	27
Coal	434	8	3	–20
Nuclear	611	67	–17	28
Average ALL[b]	164	60	13	50
MD and PA[a]				
Gas	–255	6	26	7
Coal	364	50	0	26
Nuclear	653	51	–9	26
Average ALL**	229	23	14	20
Model	BL	Heg	RPS_BL	Heg_RPS

[a] Maryland and portion of Pennsylvania within the MAAC region of the NERC and outside the RGGI region.

[b] ALL includes all generation capacity, including types not listed separately.

Figures

Figure 1. Going-Forward Costs for Existing Coal and New Gas Under Dynamic and Historic Allocation, 2025



Notes: Hg = mercury; O&M = operations and maintenance.

Figure 2. Change in Value of Existing and New Generation Assets Compared with Baseline

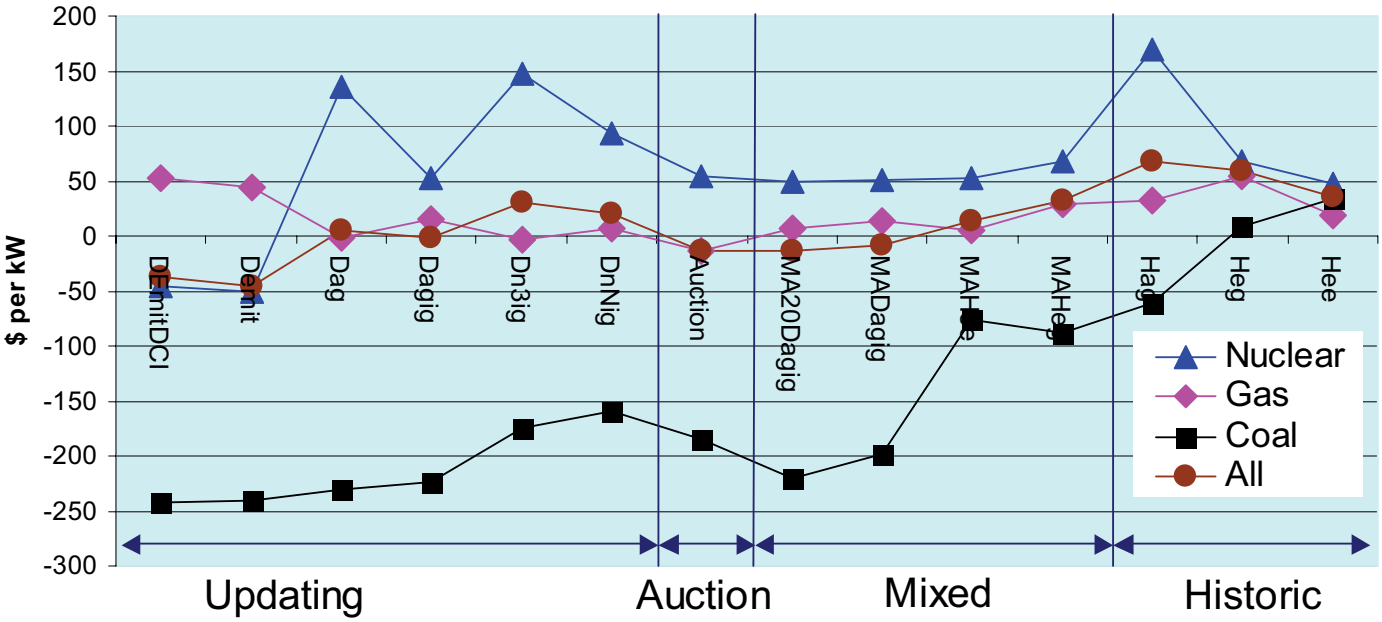
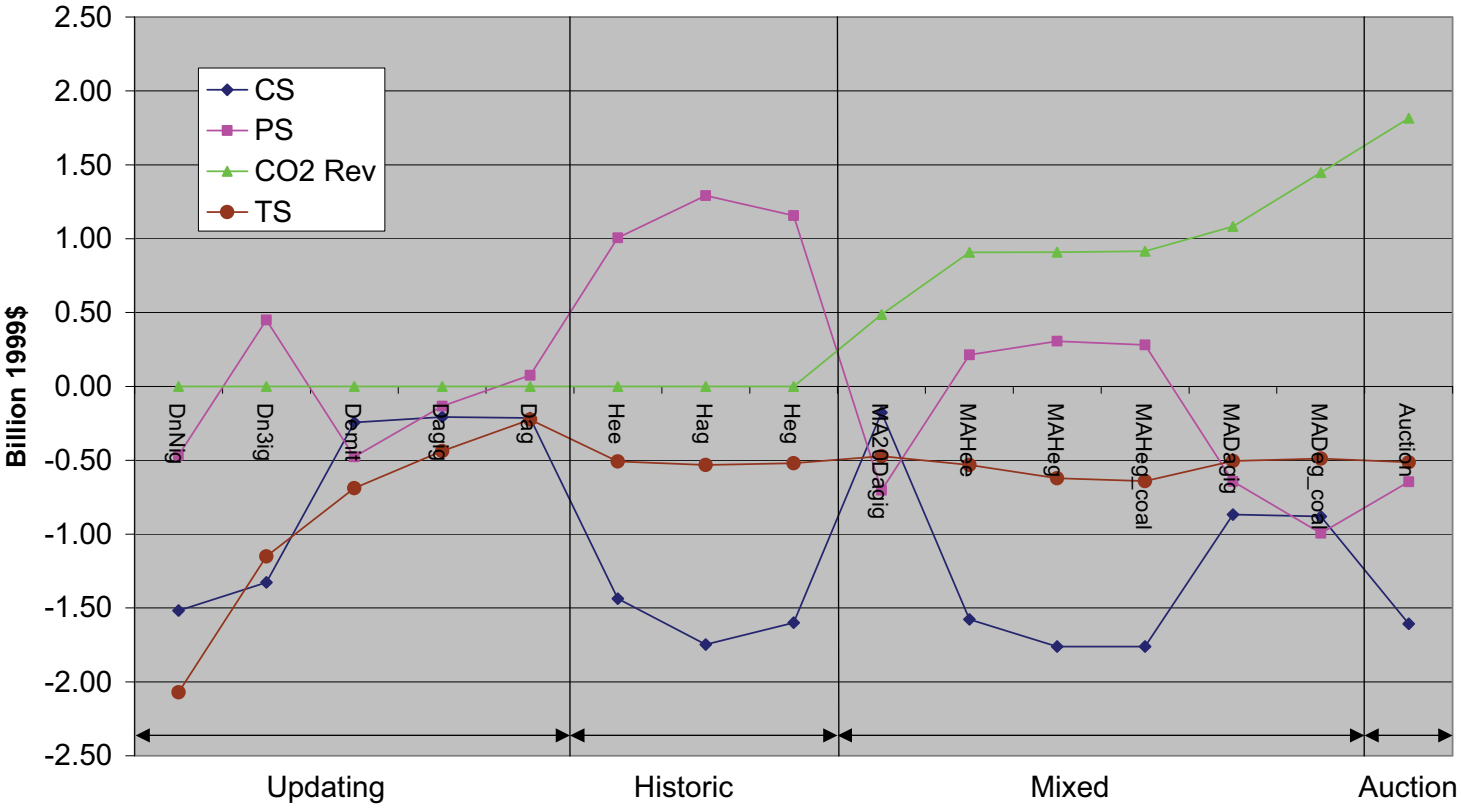


Figure 3. Change in Surplus within RGGI from Baseline, 2025



CS = consumer surplus, PS = producer surplus, CO2 Rev = CO_2 revenue, TS = total surplus.

(END OF ATTACHMENT)