Market Mechanisms and Incentives: Applications to Environmental Policy

A Workshop sponsored by U.S. Environmental Protection Agency's National Center for Environmental Economics (NCEE) and National Center for Environmental Research (NCER)

Resources for the Future
1616 P Street, NW, Washington, DC 20036
(202) 328-5000

Wednesday, April 29, 2009

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National Center for Environmental Research (NCER)

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8:30 a.m. – 9:15 a.m. **Registration**

9:15 a.m. – 9:30 a.m. **Introductory Remarks:** *Julie Hewitt, Chief, Economic and Environmental Assessment Branch, Office of Water*

9:30 a.m. – 11:20 a.m. **Session I: Fuel Economy and Gasoline Prices**
Session Moderator: *Cynthia Morgan, EPA, National Center for Environmental Economics*

9:30 a.m. – 10:00 a.m. Imperfect Competition, Consumer Behavior, and the Provision of Fuel Efficiency in Vehicles
Carolyn Fischer, Resources for the Future

10:00 a.m. – 10:30 a.m. New Vehicle Characteristics and the Cost of the Corporate Average Fuel Economy Standard
Thomas Klier, Federal Reserve Bank of Chicago, and Joshua Linn, University of Illinois at Chicago

10:30 a.m. – 10:40 a.m. Discussant: *Gloria Helfand, University of Michigan, and EPA, Office of Transportation and Air Quality*

10:40 a.m. – 10:50 a.m. Discussant: *Winston Harrington, Resources for the Future*

10:50 a.m. – 11:20 a.m. Questions and Discussion

11:20 a.m. – 12:30 p.m. **Lunch** (On Your Own)

12:30 p.m. – 1:30 p.m. Panel Discussion: Role of Market Mechanisms and Incentives to Climate Change
Moderator: *Dick Morgenstern, Resources for the Future*
Panelist: *Joe Aldy, Special Assistant to the President for Energy and the Environment*
David McIntosh, Senior Counsel in the Office of Congressional and Intergovernmental Relations
Brian Murray, Duke University

1:30 p.m. – 1:40 p.m. **Break**

1:40 p.m. – 3:30 p.m. **Session II: Applications of Environmental Trading Programs**
Session Moderator: *Will Wheeler, EPA, National Center for Environmental Economics*

1:40 p.m. – 2:00 p.m. An Experimental Analysis of Compliance in Dynamic Emissions Markets: Theory and Experimental Design
John Stranlund, University of Massachusetts - Amherst, James Murphy, University of Alaska – Anchorage, and John Spraggon, University of Massachusetts - Amherst

	2:00 p.m. – 2:30 p.m.	Can Markets for Development Rights Improve Land Use and Environmental Outcomes? *Virginia McConnell, Elena Safirova, Margaret Walls, and Nick Magliocca, Resources for the Future*
	2:30 p.m. – 2:35 p.m.	Discussant: *Heather Klemick, EPA, National Center for Environmental Economics*
	2:35 p.m. – 3:05 p.m.	Preliminary Findings and Observations on Ohio's Great Miami River Water Quality Credit Trading Program *Richard Woodward, Texas A&M University*
	3:05 p.m. – 3:10 p.m.	Discussant: *Hale Thurston, EPA, National Risk Management Research Laboratory*
	3:10 p.m. – 3:30 p.m.	Questions and Discussion
3:30 p.m. – 3:40 p.m.	**Break**	
3:40 p.m. – 5:30 p.m.	**Session III: Winners and Losers in Cap and Trade** Session Moderator: *Charles Griffiths, EPA, National Center for Environmental Economics*	
	3:40 p.m. – 4:10 p.m.	Paving the Way for Climate Policy: Compensation for Electricity Consumers and Producers Under a CO_2 Cap and Trade Policy *Karen Palmer, Dallas Burtraw, and Anthony Paul, Resources for the Future*
	4:10 p.m. – 4:40 p.m.	When Does Cap-and-Trade Increase Regulated Firms' Profits? *Dave Evans, EPA, National Center for Environmental Economics; Ian Lange, University of Stirling; and Joshua Linn, University of Illinois at Chicago*
	4:40 p.m. – 4:50 p.m.	Discussant: *Ann Wolverton, EPA, National Center for Environmental Economics*
	4:50 p.m. – 5:00 p.m.	Discussant: *Terry Dinan, Congressional Budget Office*
	5:00 p.m. – 5:30 p.m.	Questions and Discussion
5:30 p.m.	**Adjournment**	

DISCUSSION PAPER

July 2008 ■ RFF DP 08-25

Compensation for Electricity Consumers under a U.S. CO_2 Emissions Cap

Anthony Paul, Dallas Burtraw and Karen Palmer

1616 P St. NW
Washington, DC 20036
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RESOURCES FOR THE FUTURE

Compensation for Electricity Consumers Under a U.S. CO_2 Emissions Cap

Anthony Paul, Dallas Burtraw, and Karen Palmer

Abstract

Policies to cap emissions of carbon dioxide (CO_2) in the U.S. economy could pose significant costs on the electricity sector, which contributes roughly 40 percent of total CO_2 emissions in the U.S. Using a detailed simulation model of the electricity sector, we evaluate alternative ways that emission allowances can be allocated. Most previous emissions trading programs have allocated the major portion of allowances for free to incumbent firms. In the electricity sector this approach would lead to changes in electricity price that vary by region primarily based primarily on whether prices are market-based or determined by cost-of-service regulation. Allocation to customers, which could be achieved by allocation to local distribution companies (retail utilities) would recover symmetry in the effect of free allocation and lead to signficiantly lower overall electricity prices. However, this form of compensation comes with an efficiency cost that will increase the overall cost of climate policy.

Key Words: emissions trading, allowance allocations, electricity, air pollution, auction, grandfathering, cost-effectiveness, greenhouse gases, climate change, global warming, carbon dioxide, asset value, compensation

JEL Classification Numbers: Q2, Q25, Q4, L94

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Compensation for Electricity Consumers Under a U.S. CO_2 Emissions Cap

Anthony Paul, Dallas Burtraw, and Karen Palmer *

1 Introduction

A crucial decision in the design of a cap-and-trade program for CO_2 is the initial distribution, or allocation, of emission allowances. The creation of a market for CO_2 emissions would involve the largest distribution and enforcement of new property rights in North America in over a century, and the decision about allocation has efficiency and distributional consequences. The economics literature finds significant efficiency advantages to the use of an auction rather than free distribution of emission allowances. One reason is that an auction is administratively simple and precludes regulated parties from seeking a more generous future allocation. Another is that free allocation in competitive markets, like some markets for electricity in the United States, can move consumer prices away from the marginal cost of production and therefore distort resource allocation in the wider economy away from the efficient optimum. Compared with other approaches, an auction helps maintain transparency and the perception of fairness, and it leads to more efficient pricing of goods in the economy, which reduces the cost of the policy. These are important principles for the formation of a new market for an environmental commodity.

Most previous programs have relied on free distribution rather than an auction. Generally speaking, free allocation of allowances gives interested parties strong incentives to argue for an ever-increasing share of emissions allowances. In contrast, many authors suggest that auctions reduce rent-seeking, which occurs when regulated parties invest resources in trying to affect the outcome of an administrative process that distributes allowances freely. One particularly insidious aspect of free allocation is the adjustment to allocation rules for new emissions sources and for old sources that retire. The sulfur dioxide (SO_2) trading program in the United States has no adjustments for these sources, which is a virtue because it does not create incentives for investment

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behavior to deviate from what is otherwise efficient. However, most other trading programs have such adjustments. In the NO_x budget program in the United States, for example, individual states determine the allocation of allowances; most have set-asides for new sources, and sources that retire lose their allocations. Adjustments also are ubiquitous in the EU Emission Trading Scheme. The problem with such adjustments is that they alter the incentives for investment and retirement in a way that can lead to unintended consequences. For instance, there is evidence that as a result of adjustments to allocation rules for new sources in the EU, the value of emissions allowances can bias investment toward higher-emitting generating sources. This bias can result from the value of the subsidy embodied in free allowance allocations. Furthermore, the removal of allocations from sources that retire provides a financial incentive to continue the operation of existing facilities that are often inefficient and that otherwise would retire, except for the value of the allowances that they earn by remaining in operation. The use of an auction avoids this predicament entirely.[1]

The second, and equally forceful, reason that economists favor the use of auctions is that they generate funds that can be used to help reduce the cost of policy. For the purposes of minimizing the cost of climate policy on the economy and promoting economic growth, the economics literature has focused on dedicating the use of revenue from an auction to reduce preexisting taxes. Like any new regulation, climate policy imposes a cost on households and firms; that cost acts like a virtual tax, reducing the real wages of workers. This hidden cost can be especially large under a cap-and-trade program because the price placed on the scarcity value of carbon is reflected in the cost of goods that use carbon in their production, which are ubiquitous in the economy. However, the revenue raised through an auction (or an emissions tax), if dedicated to reducing other preexisting taxes, can reduce this cost. This so-called revenue recycling would have substantial efficiency advantages compared with free distribution.[2]

A compelling justification *for* free distribution of emission allowances is that public policy should do "no direct harm" through changes in government rules and regulations.[3] This justification has been invoked to argue for free allocation to firms, in order to soften the impact of the policy. However, consumers rather than firms or their

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[1] Åhman et al. 2007; Åhman and Holmgren 2006.

[2] Bovenberg and Goulder, 1996; Bovenberg and de Mooij, 1994; Golder et al. 1999; Parry et al. 1999. Smith et al. 2002.

[3] Schultze, 1977.

shareholders may be the most adversely affected by climate policy. Consequently, compensation for consumers has become a central element of the political dialogue about climate policy in the United States, which is made even more salient by recently increasing fuel prices. This paper looks at the effect on consumers from climate policy and approaches to compensating consumers.

We focus exclusively on the electricity sector. Although the electricity sector is responsible for about 40 percent of CO_2 emissions in the United States, most models indicate that under a cost-effective program, two-thirds to three-quarters of emission reductions in the first couple decades of climate policy are likely to come from this sector. Consequently the electricity sector is a very special case; it constitutes the heart of any proposal to implement market-based approaches to achieving CO_2 emission reductions. All of the important existing trading programs include the electricity sector, and usually they exclude other sources. In the United States, the sulfur dioxide (SO_2) trading program, which began in 1995, and the nitrogen oxide (NOx) trading program, which began in 1999, each has a pool of emission allowances with annual value of $1–3 billion and focus on the electricity sector almost exclusively. The EU Emission Trading Scheme (ETS), which began in 2005, includes major point sources, of which the electricity sector constitutes the most significant portion. In addition, the ten-state Regional Greenhouse Gas Initiative (RGGI), which will be the second mandatory cap and trade program in the world for CO_2 beginning in 2009, covers just the electricity sector.

Previous analysis of the electricity sector relying on detailed simulation modeling indicates that on an industry-wide basis only 6 percent of the allowance value created within the electricity sector (2.5 percent overall) is sufficient to hold the industry harmless because the majority of costs are recovered by changes in product prices.[4] General equilibrium models with less information about the structure of costs and production within the sector have found results that are broadly comparable. One study found that most of the economic effect of climate policy would be felt in the oil, gas, and coal industries, which could be compensated with just 19 percent of allowance value.[5] That paper found that the most important downstream industry to be compensated is the electricity sector, but that it would be much less affected than the primary fuel sectors.

[4] Burtraw and Palmer, 2008.

[5] Bovenberg and Goulder (2001) considered the effect of a constant $25 allowance value sufficient to achieve emissions reductions of 18 percent in the long run.

Another study estimated that the reduction in equity value in the electricity sector would be equivalent to 6 percent of the total allowance value.[6]

Although harm to producers may be concentrated and visible to the politicians, consumers in the electricity sector would incur a loss approximately eight times as great as that of producers (Burtraw and Palmer 2008, U.S. EIA 2005). Consequently, the political economy of climate policy in the United States invites some form of compensation for consumers, at least as a transition to full implementation of CO_2 allowance auctions.

The obvious way in which compensation for electricity consumers can be achieved is through free allocation of emission allowances. Emissions allowances represent enormous economic value—tens of billions of dollars annually under a federal carbon policy—that arises due to the value placed on emissions within a cap-and-trade system. Paltsev et al. (2007) put the possible annual auction revenue at $130–$370 billion by 2015, an amount equivalent to $1,600 to $4,900 per family of four. The initial distribution of just a portion of the valuable emissions allowances represents a significant potential source of compensation. The enormous value of the allowances makes this high-stakes issue perhaps the greatest political challenge in designing climate policy.

This paper highlights the important role that market organization and regulatory institutions in the electricity sector play in affecting the efficacy of climate policy. Specifically, the regulatory setting plays a crucial role in determining whether free allocation will effectively deliver compensation to its intended recipients. The U.S. electricity sector is split so that about one-third of the electricity consumed from the power grid is sold at market-based competitive prices and the other two-thirds are sold under cost of service regulation.[7]

As mentioned above, one virtue of an auction is the possibility to direct revenues to purposes that reduce overall cost. Another virtue applies specifically to the electricity sector. In regulated regions, compared with free allocation, an auction approach tends to reduce the difference between price and marginal production cost for electricity generation—a source of inefficiency that is endemic to the electricity industry.[8] Within a

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[6] Smith et al. (2002) estimated the effects of a 14 percent decrease in emissions to be achieved by 2010, and a 32 percent decrease by 2030.

[7] As of April 2007, the following jurisdictions had deregulated electricity markets: ME, NH, MA, CT, RI, NY, NJ,PA, DE, MD, DC, OH, MI, IL, and TX (EIA 2007c). In 2006 these states and the District of Columbia consumed 36 percent of all retailed electricity in the lower 48 states (EIA 2007b).

[8] Beamon et al. 2001. Burtraw et al. 2001. Burtraw et al. 2002. Parry 2005.

partial equilibrium model, the efficiency gains from using an auction in regulated settings can be at least as great as the gains from revenue recycling in a general equilibrium context.[9]

This paper incorporates the mechanisms of electricity price formation under competitive and regulated electricity markets in a detailed simulation model to investigate the magnitude of the effects that can be anticipated from alternative methods of allowance allocation within the electricity sector. We examine the effects on consumers under an auction of allowances, and under grandfathering – free distribution to incumbent electricity-generating firms. We contrast these approaches with three allocation schemes that are primarily aimed at compensating consumers. These all involve allocation to local distribution companies, the retail companies that deliver electricity to customers. The prices that these entities charge for electricity distribution are regulated throughout the United States and local distribution companies have been identified in legislative proposals as potential trustees to act on behalf of customers with respect to the allocation of emissions allowances. Various proposals have suggested allocation to local distribution companies be done on the basis of population, emissions or consumption.

Free allocation of emissions allowances to consumers or generators diverts revenues that otherwise could be dedicated to general tax relief, which offers efficiency gains and forms broad-based compensation for the diffuse effects of the policy on households. Free allocation also diverts revenues from other purposes, such as research initiatives or energy efficiency programs linked to climate policy. In the electricity sector free allocation also moves electricity price in regulated regions further away from marginal cost. Policymakers need to be cognizant of likely impacts on all affected parties, and they may want to limit and narrowly target free distribution of emissions allowances to better address a broader set of efficiency and compensation goals.

2 Analysis of the Electricity Sector

The electricity sector deserves special attention not only because of the emission intensity of its product, but also because of the long-lived nature of capital and the idiosyncratic way in which electricity markets are organized. Regulation of generation and retail services are generally left to states. However, because electrons flow freely

[9] Burtraw et al. 2001; Parry 2005.

over the wires and across state lines, the transmission grid is regulated by the federal government. The way that most states choose to regulate generation and retail services typically differs, and the choices vary across the states.

2.1 Institutions

Economists tend to think most markets are fundamentally competitive, at least in the long run. As a general principle, in competitive markets free allocation to firms will not benefit consumers because the economic value of a commodity in a competitive market is determined by its scarcity. Emissions allowances are a valuable asset, and as long as there is a liquid allowance market, a firm can sell allowances at the market price instead of using them for its own compliance responsibilities. The firm will recognize the lost opportunity for revenue from the sale of an allowance each time it uses the allowance itself for compliance. So in most markets economists would not expect to see consumers receive the benefit from free allocation to firms. Instead the value of emission allowances would be captured by shareholders who, in turn, would recognize their opportunity cost in production decisions.

The fact that a firm in a competitive market will charge its customers for the use of an asset that the firm has received for free is often a difficult idea for people to grasp, but it is wholly consistent with economic theory and it is in general what is observed in empirical studies. Indeed, sometimes economists seek evidence of noncompetitive behavior and "market power" by looking for instances when the price of a good differs from the cost of factor inputs used in its production. An emissions allowance in a cap-and-trade program is one such factor. If a firm did not pass through the cost of an allowance in the pricing of its product, it would be *prima facie* evidence of a noncompetitive market—and of possible market manipulation.

However, a substantial portion of the electricity sold in the United States is not traded in competitive markets, but instead sold in markets that are subject to cost-of-service regulation. In these cases regulators set prices to allow firms to recover their costs, which are usually calculated on an original-cost basis. If allowances are received for free by regulated electricity generators, then the addition to the cost basis for the purpose of cost recovery is zero. Roughly speaking, this situation applies to about two-thirds of the electricity customers in the country. In these areas the benefit of free allocation to emitters or producers can be expected to be passed on to consumers.

The contrast between regions with market-based electricity prices and regulated prices could yield asymmetric changes in retail electricity prices under free allocation to firms. These asymmetric effects on electricity consumers, in which free allocation to producers benefits consumers in regulated regions of the country, but not those in regions with market-based prices, introduce a challenging dilemma to climate policy.

An alternative approach to compensation is allocation to local distribution companies (LDCs), the retail electricity companies that deliver electricity to customers and that could be directed to act as trustees on behalf of consumers. Although retail companies would see the cost of power in the wholesale power market increase under a cap-and-trade program, they would have substantial allowance value to rebate to consumers, and this would reduce the cost impact for their customers in competitive and regulated regions alike. Virtually the entire country is regulated in retail services, and some recent proposals, including the Lieberman–Warner climate proposal (SB 2191), would allocate some fraction of allowance value to LDCs for compensation to electricity consumers through rate reductions. This approach is expected to have the advantage of maintaining symmetry on a regional basis in the electricity sector.

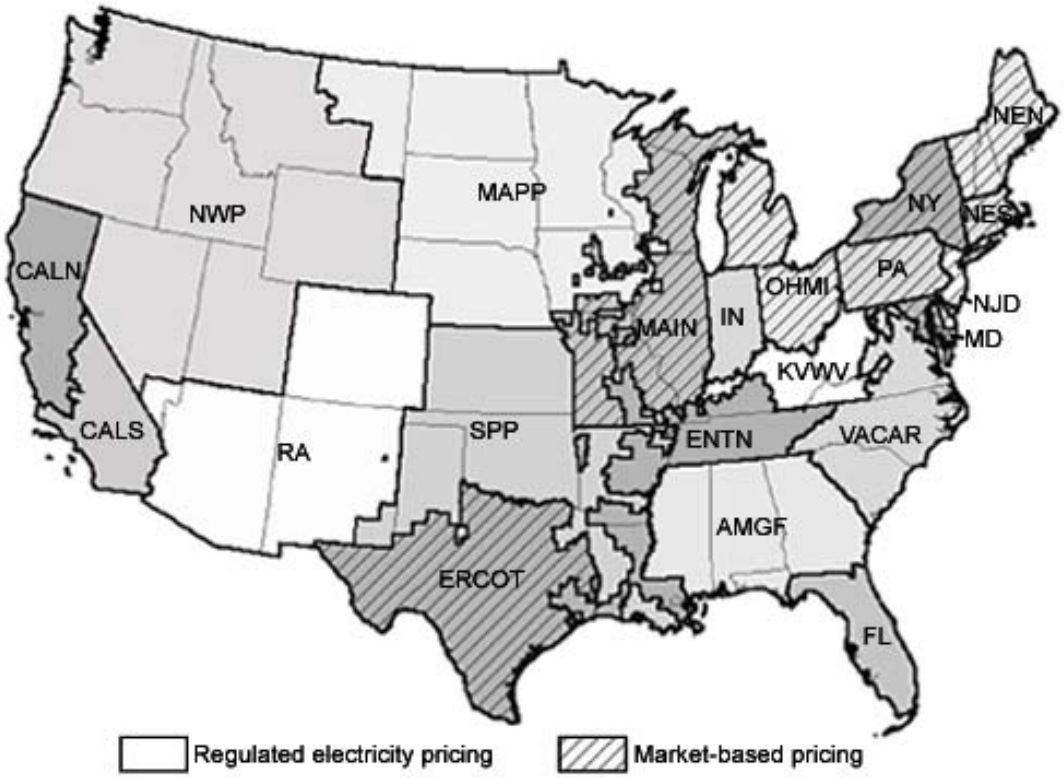
2.2 Model

Several features of the market determine the relationship between CO_2 allowance price and the electricity price (Reinaud 2007). The most important are the fuel use, the portfolio of generation technologies, the nature of economic regulation and market structure, and the approach to allocation. To analyze these relationships we rely on a detailed simulation model of the electricity sector known as the Haiku Electricity Market Model, which is maintained by Resources for the Future. Haiku is a deterministic, highly parameterized model that calculates information similar to the National Energy Modeling System used by the Energy Information Administration, and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (EPA). The Haiku model is distinguished from these models by its capacity to evaluate policy effects on consumer and producer surplus in the electricity sector and express these as a measure of economic welfare within the national and regional electricity markets.

The Haiku model simulates equilibrium in regional electricity markets and interregional electricity trade with an integrated algorithm for emission control technology choices for SO_2, NO_x, mercury and CO_2. The composition of electricity supply is calculated using a fully integrated algorithm for capacity planning and

retirement coupled with system operation in temporally and geographically linked electricity markets. The model solves for electricity market equilibrium in 21 Haiku market regions (HMRs) within the continental United States. Each of the 21 HMRs is classified by its electricity pricing regime as having either competitive or regulated electricity pricing, as shown in Figure 2.2-1. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to market-based pricing of generation continue that practice, and those that have not made that move remain regulated. The price of electricity to consumers does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

Figure 2.2-1 Haiku Market Regions and Electricity Pricing



Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial). Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity

generation plants in the country. Investment in new generation capacity and the retirement of existing facilities is determined endogenously in a dynamic framework, based on capacity-related costs of providing service in the future ("going forward costs"). Operation of the electricity system ("generator dispatch") in the model is based on the minimization of short-run variable costs of generation.

Equilibrium in interregional power trading is identified as the level of trading necessary to equilibrate regional marginal generation costs net of transmission costs and power losses. These interregional transactions are constrained by the level of the available interregional transmission capability as reported by the North American Electric Reliability Council (2003a, 2003b).[10] Factor prices, such as the cost of capital and labor, are held constant. Fuel prices are benchmarked to the forecasts of the Annual Energy Outlook 2007 for both level and elasticity (U.S. EIA 2007). Coal is differentiated along several dimensions, including fuel quality and content and location of supply; and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. Other fuel prices are specified exogenously.

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions, EPA's Clean Air Interstate Rule caps on emissions of SO_2 and NO_x, and the Regional Greenhouse Gas Initiative (RGGI) cap on CO_2 emissions, are imposed as constraints on the sum of emissions across all covered generation sources in the relevant region. Emissions of CO_2 from individual sources depend on emission rates, which vary by type of fuel and technology, and total fuel use at the facility. The sum of these emissions across all sources must be no greater than the total number of allowances available, including those issued for the current year and any unused allowances from previous years when banking is permitted. In this analysis, banking for CO_2 is not enabled. Rather, year-specific emission targets are taken from the Energy Information Administration analysis described below, to which the simulations are calibrated. This

[10] Some of the HMRs are not coterminous with North American Electric Reliability Council (NERC) regions and therefore NERC data cannot be used to parameterize transmission constraints. Haiku assumes no transmission constraints among OHMI, KVWV, and IN. NER and NEO are also assumed to trade power without constraints. The transmission constraints among the regions ENTN, VACAR, and AMGF, as well as those among MAACR, MD, and PA, are derived from version 2.1.9 of the Integrated Planning Model (EPA 2005). Additionally, starting in 2014, we include the incremental transfer capability associated with two new 500-KV transmission lines into and, in one case, through Maryland, which are modeled after a line proposed by Allegheny Electric Power and one proposed by PEPCO Holdings (CIER 2007). We also include the transmission capability between Long Island and PJM made possible by the Neptune line that began operation in 2007.

approach allows for a more transparent comparison of the effects of different approaches to allocation because the quantity of emissions in each year is held constant.

3 Scenarios

One way that electricity consumers can be compensated directly is for each citizen to receive allowance value directly. This approach has recently been described as "cap and dividend" because the allowance value would be refunded as a dividend on a per capita basis. This approach would be among the most progressive in its distributional consequences (Burtraw et al. 2008; Boyce and Riddle 2007). The Center on Budget and Policy Priorities (2007) identify another approach that would take advantage of information about household income to target the most disadvantaged households using just a portion of the allowance value.

Environmental advocates typically take a different view, however, aiming to direct auction revenue to complementary initiatives to reduce emissions. For example, the Model Rule for the 10 northeastern U.S. states in RGGI specifies that each state must allocate at least 25 percent of its budgeted allowances to a consumer benefit or strategic energy purpose. These "consumer benefit" allowances are to be sold or otherwise distributed to promote energy efficiency, to directly mitigate electricity ratepayer impacts, or to promote lower-carbon-emitting energy technologies. (Most of these ten states have indicated their intention to auction nearly 100 percent of their budgeted allowances.) Ruth et al. (2008) found the dedication of 25 percent of the allowance value to investments in end-use efficiency would offset any increase in retail electricity price from the policy. A similar plan to direct a portion of allowance value to strategic energy purposes is part of the European Commission's proposal for moving to an auction in the EU ETS beginning in 2013. The merits of this strategy rest on the belief that there exist market barriers that prevent the realization of opportunities for improving efficiency in the end-use of energy or to bringing renewable energy sources to market. The merits rest as well on the ability to design institutions that can use allowance value effectively to overcome these barriers. Other claims for allowance value are based on the need to accelerate the adaptation to climate change. Atmospheric scientists tell us that we are already at the point where some climate warming is inevitable and that adaptation will be necessary. Adaptation will involve significant investment by the private and public sectors. An auction provides revenues that could be directed to this variety of purposes.

The scenarios we model are limited to the electricity sector, but they capture the heart of the debate regarding treatment of allocation for that sector in the United States.

The allowance distribution plan for Lieberman–Warner (S 2191) dedicates 22 percent of the allowances in the year 2012 to states in one fashion or another.[11] One major portion is directed to electricity local distribution companies (9 percent) and natural gas distribution companies (2 percent). These allocations are intended to address a variety of purposes including promotion of investment in end-use efficiency or direct rate relief for customers. Other proposals have been even more aggressive.[12] The Jeffords bill in 2002 would have allocated two-thirds of emissions allowances to the states for determination of ultimate allocation by trustees. It would be plausible for this decision to be left to the state public utility commissions, who would act as trustees on behalf of consumers.

3.1 Alternative Methods for an Initial Distribution of Emissions Allowances

The Lieberman–Warner proposal includes a cap-and-trade system for the entire economy with point of compliance at upstream fuel supply in almost every case. In general, the policy would require fuel suppliers to surrender allowances equal to the carbon content of the fuel and byproducts that they sell or consume in their refining and manufacturing processes. The exception is coal-fired power plants, which would have compliance responsibility at the point of consumption. For natural gas use in the downstream electricity sector the cost of the cap-and-trade system would be perceived as a change in the relative cost of fuel. Fuel with relatively high carbon content would be expected to have a higher price because of the opportunity cost of emissions allowances that fuel suppliers would have to surrender to bring that fuel to market. For coal-fired power plants the cost of power would depend on the method of allocation and the type of regulation in place.

In general, it is vital to recognize that the point of allocation of emissions allowances is distinct from the point of compliance. We evaluate several methods for the initial distribution of emissions allowances (Sterner and Muller 2007). One alternative is **upstream allocation**, with all emissions allowances distributed initially to fuel suppliers and with no allowances distributed to the electricity sector. Within the electricity sector, this approach is equivalent to an **auction** regardless of how the allowances are actually distributed to fuel suppliers because electricity generators purchase their emissions allowances bundled along with their fuel through an increase in the price of fuel.

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[11] The remainder are allocated using a mix of free allocation to industry and an auction.

[12] The National Association of Regulatory Utility Commissioners (April 21, 2008) has called for 100 percent of the allowances to be distributed for free in the electricity sector to be given to LDCs.

As one alternative to an auction, we consider free distribution of allowances to incumbent firms in the electricity sector 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, which we do not explore here, 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 them according to various measures, such as the share of electricity generation or heat input (a measure related to fuel use) or a share of emissions at a facility (Burtraw et al. 2001; Fischer and Fox 2004; Rosendahl 2008). An updating approach leads to lower electricity prices than an auction or historic approach and is expected to have greater social costs because it does not provide the same incentive through higher prices for consumers to improve the efficiency of energy use (Burtraw et al. 2006).

The focus of this analysis is the modeling of allocation to local distribution companies, the retail companies that directly serve customers. This approach is described as "**allocation to load"** or **"load-based allocation**" because in one form or another it would allocate to customer demand for electricity (load). We model this at the level of 21 regions in our model, and based on three different metrics. One is the portion of electricity consumption in each region, a second is the portion of population and the third is the portion of emissions. These metrics are calculated on a one-time basis, drawing on the baseline model run for each simulation year in the model. The value of emissions allowances under allocation to load is used to offset the average cost of electricity directly, for example by offsetting the transmission and distribution charge. Although electricity prices vary by customer class because of varying time profiles of demand and different shares of transmission charges assigned to each class, we assume a uniform distribution of the value of allowances in reducing electricity price across all customers.

3.2 Baseline

The baseline scenario is constructed to incorporate all major federal legislation governing airborne emissions from the electricity sector including Title IV and CAIR for SO_2 emissions, the annual and ozone season caps on emissions of NO_x under CAIR, and CAMR for mercury emissions. Also included are some state level legislation, including RGGI, and other policies that are specific to individual states. For nuclear capacity additions, Haiku uses the regional output of the EIA National Energy Modeling System

for 2007 as capacity limits on new construction of nuclear plants. All of these potential capacity additions are east of the Mississippi River (U.S. EIA 2007).

Two of the most important baseline scenario assumptions are the treatment of Federal Renewable Energy Production Tax Credit (REPTC) and of state level Renewable Portfolio Standards (RPS) in several western states, including California. The REPTC provides a production tax credit of $19/MWh to new wind, geothermal, and dedicated biomass generators, and a credit of $9.50/MWh is available to new landfill gas and non-dedicated biomass generators.[13] Since the federal REPTC has repeatedly been renewed just prior to lapsing and has actually lapsed three times for a total of 16 months (over the 15 years since it was initially instituted) before being reinstituted, it is modeled in perpetuity in Haiku as a tax credit that is received with 90 percent probability. The state level RPS mandates within the Western Electricity Coordinating Council (WECC) region require substantial increases in renewables generation in the coming years. The resulting capacity additions are not modeled endogenously within Haiku. Instead, we force new renewable capacity into our model in order to meet these standards in the western states[14] according to forecasts provided by Energy and Environmental Economics, Inc (E3).[15] These forecasts of renewable resource additions include the planned capacity additions for wind, geothermal and biomass reported by the Transmission Expansion Planning Policy Committee (TEPPC) along with additional resources that E3 forecasts would be needed to meet RPS standards. These renewable policies are significant because of their potency in reducing emissions, but also because by including them in the baseline it reduces the cost of achieving a specific emissions cap under the policy scenario.

3.3 Policy Scenario

The emissions reduction targets that we model are taken from the U.S. Energy Information Administration modeling of the Lieberman–Warner proposal (U.S. EIA 2008). From that modeling we take the CO_2 emissions determined at the national level as given, and we assume it is not affected by small changes in the electricity sector that result under the variations of policies we model. We do not allow inter-annual banking in the runs of our model, although it is implicit in the quantity targets we take from EIA.

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[13] All values are reported in 2004$ unless indicated.

[14] The western states for which we forced in new renewables capacity include California, Arizona, Montana, Colorado, New Mexico, Utah, Nevada and Wyoming.

[15] "Electricity and Natural Gas GHG Modeling: Methodology and Key Revisions," Slides 38-39, April 21, 2008; <http://www.ethree.com/GHG/E3_CPUC_GHG_21April08.pdf>.

Investment and operational decisions in our model respond to this fixed emission target. In reality (as opposed to in the model), the electricity sector decisions would play a role in the determination of the electricity sector's share of national emissions that obtain under each policy scenario, but we maintain the fixed quantity to achieve comparability across scenarios. Since the emission quantity is the same and the models are different, our model will result in a different level of allowance price and electricity price across scenarios and different from that obtained in the EIA exercise.

In addition to the no-policy baseline, five policy scenarios are modeled. These are comprised of an allowance auction, free allowances to incumbent generating firms (grandfathering), and the three allocation-to-load scenarios described above, based on consumption, population and emissions.

4 Results

The effect of climate policy on electricity consumers depends on several factors that vary by region of the country including the fuel mix and technology used for generating electricity, economic regulation and the approach to allocation. Moreover these factors interact. For example, the portfolio of generation technology determines the fuel that is used at the margin at different times of day and year, and the economic regulation in the region determines whether changes in average or marginal cost determine changes in electricity price. This analysis focuses on the role of allocation, but highlights the important interactions among all these factors, particularly how different approaches to allocation can have different effects depending whether markets are regulated.

If allowances are allocated upstream or auctioned to electricity producers, the opportunity cost of the allowances would be reflected in the price of electricity in both regions with competitive electricity markets and regions subject to cost-of-service regulation. We find that if allowances are allocated for free to generators on the basis of historic generation, the effect on electricity prices and thus on consumers would depend on whether electricity markets are regulated or not. Allocating allowances to local distribution companies would largely erase these inter-regional differences based on regulation, with remaining differences across regions being largely a function of the mix of resources used to generate electricity within a region.

This modeling exercise was performed for a horizon beginning in 2010 and ending in 2025. For expositional simplicity this paper focuses on the results obtained for the year 2020.

4.1 Allowance Allocation and Consumers

The quantitative effect of different approaches to allowance allocation on average electricity prices is shown in Table 4.1-1. The table reports price effects in each Haiku market region as well as aggregate price effects aggregated into regions defined by geography and by regulatory institutions. The auction has the biggest effect on electricity prices in both types of regions and nationwide. Prices in competitive regions increase by $8.50 per MWh with an auction, while in regulated regions the increase in average price due to the policy is closer to $6 per MWh. The difference is related to the differences in resource mix between the two types of regions and the difference in regulation. Under cost-of-service regulation, allowance costs from an auction are passed through to consumers in a way that makes the generators whole and thus these costs are averaged over all MWh sold. However, in competitive regions, the allowance cost to the marginal generator is passed through in the market-determined price that is charged for all electricity, which may be generated with an emitting technology or a non-emitting technology at any point in time. Many generators, particularly those with substantial reliance on non-emitting technologies like nuclear or hydro, will earn rents from this type of pricing (Burtraw and Palmer, 2008). Nationwide the price increase under an auction averages $7 per MWh.[16]

When allowances are grandfathered to generators based on historic generation the inevitable effect of the policy is an electricity price reduction in regulated regions relative to the auction scenario. This reduction leads to increased consumption of electricity, more power imported from neighboring competitive regions and a resultant increase in the electricity price in the competitive regions relative to the auction. Relative to the baseline, competitive regions will see an increase in electricity prices of nearly $10 per MWh under grandfathering, while regulated regions will actually experience a small decline in prices of $1 per MWh. The decline in prices is made possible by the disconnect in

[16] This price effect is difficult to compare directly with the EIA analysis. US EIA (2007) models a mixed allocation of some auction, some free allocation. Also they do not model the continuing availability of the REPTC, even on a probabilistic basis. Further, the EIA analysis of an economy-wide policy will have broader effects in primary fuel markets, especially with respect to the change in demand for natural gas and resultant price change. The demand response we capture is only that pertaining to the electricity sector. US EIA finds the change in electricity price to be $4.7/MWh (2004$).

regulated regions between marginal and average costs. Marginal costs will rise by nearly $10 per MWh, but average costs will fall as a result of the displacement of relatively carbon intensive generation resources in the baseload part of the supply curve with less carbon intensive resources, especially subsidized renewable resources. This also allows for the profitable export of grandfathered allowances. Nationwide the price increase under grandfathering will be roughly one-third of what it will be with an auction.

Table 4.1-1. Change in Electricity Price by Region and Allocation Method in 2020 (2004$/MWh)

Region	Auction	Grandfathering	Load-Based (population)
Regulated Regions	6.1	(1.0)	(0.0)
Competitive Regions	8.5	9.9	1.8
National	7.0	2.7	0.6

The asymmetric consequence of grandfathering emission allowances is illustrated in the first two panels of Figure 4.1-1, which illustrates the distributions of price changes across regions under different allocation approaches. The graphs in this figure provide histograms of the frequency of various levels of electricity price change resulting from the cap and trade policy under different allocation approaches. The horizontal axis in each graph indicates the size of the change in electricity price while the vertical axis indicates the number of billion kWh of electricity consumption that experience each level of price change from the policy. Changes associated with regulated and competitive regions are indicated in contrasting shading.

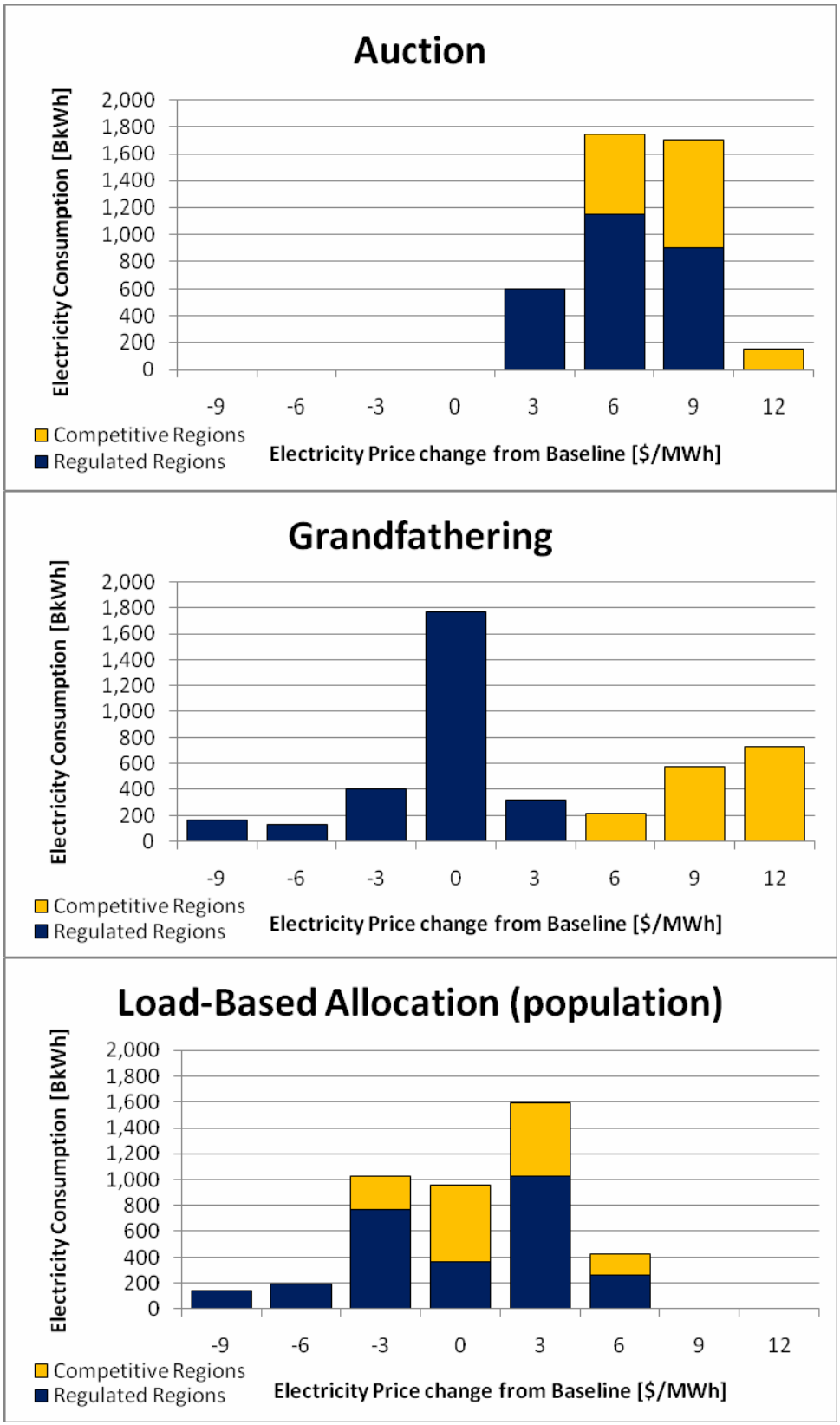
The top panel of the figure shows how electricity prices change in 2020 in response to a climate policy with an allowance auction. Under the auction we see that the average change in electricity price nationwide is roughly $7 per MWh with impacts in particular regions varying between $1.80 and $10.60 per MWh. This graph shows that there is much overlap between price impacts in regulated and competitive regions under this policy. The main differences in the distribution of the change in price result from the fuels and technologies used to generate electricity in each region. There remain important differences between regulated and competitive regions in the rates at which compliance costs are passed through to customers as changes in electricity prices because of the difference in average and marginal cost pricing. However, the difference among regions under an auction, and hence the explanation for the distribution of the change in costs across regions, is fundamentally driven by the change in the emission intensity of

electricity generation. The middle panel of the graph shows the distribution of price effects across regions under grandfathering. This figure illustrates the dramatic difference between regulated regions and competitive regions. In regulated regions, consumers benefit from a grandfathering approach and price increases are much reduced. As shown in appendix Table 1, in two regions, Indiana and a region spanning Kentucky, West Virginia and a small part of Virginia, prices actually fall by roughly $7 and $9 per MWh, respectively, while several other regions experience price declines of between $0.20 and $1.80 per MWh. In competitive regions the distribution of price impacts actually shifts slightly to the right, reflecting the increase in generation costs associated with the increase in demand (due to the lower price) in regulated regions, compared to an auction. The biggest price increases occur in Pennsylvania (PA) and the region that includes Ohio and Michigan (OHMI).

The asymmetry in price effects under grandfathering between regions under different pricing regimes has posed one of the major political challenges to the design of climate policy in the United States. While a point of departure for policy design from the perspective of the electricity industry has been free allocation of emission allowances, analysis has informed industry members of their opposing interests, depending on what kind of region they are in, and increasingly consumer interests have taken notice. The emerging attention being given to load-based allocation is potentially one way for the industry to navigate these issues.

Compared to an auction, load-based allocation attenuates price increases from climate policy in both competitive and regulated regions. As a point of departure, we consider first LBA on the basis of population. In practice this would be implemented by initially apportioning allowances to the service territories of individual retail utilities, or more probably to states and charging state public utility commissions to complete the apportionment to service territories. In our model, this is implemented by apportioning allowances among the 21 market regions according to population. Table 4.1-1 indicates that in competitive regions the price increase from the policy falls from $8.50 per MWh with an auction to $1.80 per MWh with the load-based allocation approach. In regulated regions, the average price of electricity is unchanged under the climate policy with load-based allocation compared to the baseline. Nationwide electricity price increases by $0.60 per MWh. In general, load-based allocation dramatically reduces the effect of the policy on consumers in both competitive and regulated regions relative to the auction scenario.

Figure 4.1-1. Distribution of Electricity Price Effects in 2020



The bottom panel of Figure 4.1-1 illustrates this effect in a histogram that can be compared with the other approaches to allocation. To a rough approximation, load based allocation restores the symmetry in the price impacts on regulated and competitive regions that would be observed under an auction, albeit at much lower levels. This has made load-based allocation increasingly popular to overcome political opposition to the effect of climate policy on electricity prices.

Giving allowances away for free will help to soften the impact of the policy on consumers, but it will do so at a cost. By reducing prices, the load-based allocation approach and, for consumers in regulated regions, the grandfathering approach, mute the incentive to conserve electricity that exists with an auction. The effective subsidy to electricity consumption causes generation to be higher, leading to a higher demand for CO_2 allowances. This results in an increase in allowance price, which will spread throughout the economy under an economy-wide cap-and-trade program. Allowance prices in 2020 under the different allocation approaches are reported in Table 4.1-2. The table indicates that allowance price in 2020 rises from $14.10 per ton CO_2 under an auction to $15.30 under grandfathering and even higher, to $15.80, under a load-based approach.

Table 4.1-2. National CO_2 Allowance Price in 2020 (2004$/ton)

Auction	Grandfathering	Load-Based (population)
14.1	15.3	15.8

4.2 Different Flavors of Load Based Allocation

In a second set of simulation runs we consider three alternative bases for determining a region's load-based allocation of emission allowances. Previously we considered total population in the region, and in addition we consider total electricity consumption and total emissions from electricity generation.[17] Under load-based allocation based on population, heavily populated regions would receive a greater share of the allowance value than less populated ones. In comparison, the consumption-based approach would tend to favor consumers who reside in regions where electricity

[17] The National Association of Regulatory Utility Commissioners (April 21, 2008) call for load-based allocation on the basis of historic emissions.

consumption per capita is higher and the emissions-based approach would favor consumers in coal-intensive regions. The emissions-based approach introduces a more prominent role for the resource mix in the determination of each region's share of emission allowances, as occurs with grandfathering, except in this case the benefits of free allocation in both regulated and competitive regions accrue to consumers instead of to generators.

Varying the basis for allocation to local distribution companies from population to another measure will have different effects on electricity prices in different regions. Appendix Table 2 shows some of the factors underlying those differences. For example, both Northern (CALN) and Southern California (CALS) have low consumption per capita and conversely relatively high population per unit of consumption relative to many other regions in the model, and thus would receive a larger share of emissions allowances under a population-based allocation than a consumption-based approach. A population-based approach would produce a more substantial price reduction, especially in Northern California, which has a low rate of electricity consumption per capita.[18] An emissions-based approach also would not be favorable for California, which has a relatively clean portfolio of generators. In contrast, a coal-intensive region such as the one including much of Kentucky, part of Virginia and West Virginia (KVWV) has relatively high CO_2 emissions per capita and thus consumers in that state are expected to find an emissions-based approach to allocation to be more favorable.

To provide a summary of these different regional effects we aggregate the 21 Haiku market regions into six regions:

- Northeast states in the Regional Greenhouse Gas Initiative (RGGI)
- Southeast
- Midwest and Appalachia
- Plains
- Rocky Mountains and Northwest
- California

The composition of each region is shown in the map displayed in Figure 4.2-1.

[18] Note that the measures of electricity consumption per capital reported in the table include total consumption by all classes of customers in the state divided by total population.

Figure 4.2-1 Aggregated Regions

Table 4.2-1 reports the regional electricity price changes in 2020 under the three different approaches to load-based allocation. The last row of the table reports the average price changes for the nation as a whole and shows that varying the basis for load-based allocation does not have much impact on average electricity price nationwide. Under all three load-based scenarios national average electricity price rises by less than a dollar per MWh, which is substantially less than the price difference resulting under an auction. However, this apparent similarity masks some substantial differences across regions.

The biggest difference in price effects across the different load-based approaches occurs in California, where allocation to local distribution companies based on population yields an average electricity price that is $8.50 below baseline levels (e.g. price actually falls under the climate policy) while an allocation based on emissions yields a price that is $3.10 above baseline levels, on par with the price increase experienced under grandfathering. If allocation to local distribution companies is based on electricity consumption, the average price is also lower than in the baseline, by $3.60.

Table 4.2-1. Change in Electricity Price by Region and Approach to Load-Based Allocation in 2020 (2004$/MWh)

Region	Load-Based (population)	Load-Based (consumption)	Load-Based (emissions)
RGGI	(1.4)	2.0	5.3
Southeast	0.6	(0.8)	(0.3)
Midwest and Appalachia	4.2	3.5	0.5
Plains	2.3	1.5	0.0
California	(8.5)	(3.6)	2.9
Rockies and Northwest	(2.6)	(2.2)	(2.1)
Competitive	1.8	2.7	2.6
Regulated	(0.0)	(0.6)	(0.7)
National	0.6	0.6	0.4

The second biggest differences in price effects across the three load-based allocation scenarios are found in RGGI. Electricity consumers in the RGGI states would clearly be better off when allocation is based on population and average price is $1.40 per MWh lower than in the absence of a climate policy. Under the consumption-based allocation to local distribution companies, prices in the RGGI states increase by $2 per MWh. Consumers in this region are least well off under an emissions based approach, which produces average price increases under the policy of $5.30 per MWh. Some parts of this region experience substantially higher price increases; in northern New England, which relies heavily on hydro and nuclear power, average electricity prices will increase by $9.20 under the emissions-based approach.

The only region to experience price increases under all three load-based approaches is the Midwest and Appalachia. In this region average price rises by $4.20 in the per capita scenario, driven in large part by even bigger increases in coal-rich Kentucky and West Virginia. When emissions are used as the basis for allocation to load, the average electricity price rises by only $0.50. However, this increase masks large declines in price in the states of Kentucky, West Virginia and Indiana that are offset by price increases in the region that combines Illinois and Wisconsin, which has a fair amount of nuclear generation. Customers in the plains states also experience price increases larger than the national average under the population and consumption based

approaches. However, average price remains virtually on par with baseline levels under the emissions based approach.

Our findings suggest that electricity consumers in the western region excluding California should be largely indifferent between the three approaches to load-based allocation, all of which produce price drops in 2020 of roughly $2.00. Closer examination of the results for the two Haiku market regions that comprise this larger region suggest slightly greater differences in price effects between the consumption-based and the emissions-based approaches. In particular the consumption based approach leads to slightly larger price drops in the northern part of this region, which is rich in hydro resources as well as other types of renewables. Consumers in the southern part of this region fare better under an emissions based approach as coal plays a greater role in the generation mix there.

4.3 Efficiency Consequences

The beneficial effects of load-based allocation accrue to electricity consumers through lower electricity prices; however, the downside of a load-based approach is that it yields a higher allowance price than would prevail under an auction. This effect on allowance price is essentially invariant with respect to the basis on which allowances are allocated to local distribution companies. Table 4.3-1 shows the CO_2 allowance price under all three approaches and reveals that allowance prices are little changed across the three scenarios, and they each lead to significant differences in allowance price compared to an auction.

Table 4.3-1. National CO_2 Allowance Price in 2020 (2004$/ton)

Load-Based (population)	Load-Based (consumption)	Load-Based (emissions)
15.8	16.0	16.0

From a sector-specific perspective, the difference in allowance price is not significant, but within the broader economy it signals that greater use of resources and greater cost would be required to achieve emission reduction goals. Any kind of free allocation including grandfathering will raise the allowance price, but the load-based approach does so most importantly. While grandfathering is generally intended to compensate the owners of incumbent facilities that will be regulated by climate policy, in contrast, free allocation to load is a subsidy to consumers of electricity. We find it would

raise the price of allowances by about 12 percent compared to an auction. As a consequence, within a nationwide cap-and-trade program, other actors in the economy such as industries that use natural gas, or households that use fuels for home heating, or people who drive cars, would pay for this subsidy to electricity by higher prices for the use of energy elsewhere in the economy.

The subsidy to electricity consumption has the effect of reducing the incentive for consumers to make investments in end-use efficiency. Recent analyses (McKinsey 2007, Nadel et al. 2004) suggest that there are substantial opportunities to improve the efficiency with which electricity is used in the economy. While government programs and standards may contribute to the realization of these efficiency gains, another important component is the capital purchase decisions of individuals. If electricity price rises less due to free allocation to electricity consumers then those consumers will have less incentive to purchase efficient air conditioners, refrigerators, etc., causing other sectors to do more work to achieve overall emission reductions.

Electricity consumers, and the industry that supplies them with power, have a parochial interest in trying to lessen the impact of climate policy on prices and in capturing the value for the electricity sector associated with placing a scarcity value on CO_2 in the economy. However, there is no economic logic why the value of emission allowances should be reserved for a sector just because it has historically been the source of emissions. The parochial assignment of allowance value to any one sector of the economy could lead to different marginal costs for emission reductions throughout the economy, and it could lead to some sectors having to achieve greater emission reductions than would be efficient overall, which offers the prospect of raising the cost from a nationwide perspective.

5 Conclusion

It is noteworthy that precisely because the cost of climate policy is large, a good way to achieve broad-based compensation is to reduce the overall social cost of the policy. Recycling revenue raised under an allowance auction to reduce preexisting taxes, helps achieves efficiency goals and these achievements are compounded since this approach reduces the overall cost of climate policy, thereby lessening the impact on households overall. However, it would not succeed in compensating lower income households who spend a larger portion of their income on energy than wealthier households who would benefit the most from revenue recycling. Burtraw et al. (2008) find that a proportional reduction in labor income taxes would be highly regressive.

One approach to compensating households that is embodied in current legislative proposals is free allocation to electricity customers, to be achieved by free allocation to local distribution companies. This approach seems appealing because customers may have relatively little opportunity to reduce electricity use in the short term, at least until they have the opportunity to make new capital investments in appliances, home weatherization, etc.

From the national perspective, we find significant benefits for electricity consumers from free allocation to local distribution companies. In addition, this approach reconciles the important regional differences that would emerge with a grandfathering approach that distributed allowances for free to incumbent emitters. However, the benefits that emerge at the national level mask important differences across regions that depend on how the allocations are determined. Allocation to local distribution companies based on population could yield electricity prices in 2020 for populous regions with relatively clean sources of electricity generation that are actually below prices in the absence of climate policy. Consumers residing in regions that rely heavily on coal will tend to fare better under an approach that uses emissions to determine allocation.

We also find free allocation to local distribution companies comes with an important efficiency cost, not just in a general equilibrium context stemming from foregone revenue but also due to the market dynamics in the regulated industries. When electricity customers do not see the increase in retail electricity prices, they do not have an incentive to reduce electricity consumption. Across the sector, this effect would lead to more electricity consumption, and under an economy-wide program, it would lead to more emissions from the electricity sector, requiring more reductions from other sectors. This is expected to raise the overall cost of achieving climate goals. However, the political virtue of this approach is that using allocation to load provides a mechanism in the short run to avoid sudden changes in electricity prices for consumers. Because free allocation to customers has the political virtue of lessening the price effect, it may provide for a useful transition path to phasing in a full auction in the electricity sector.

Appendix

Appendix Table 1. Change in Electricity Price from by Region in 2020 (2004$/MWh)

Electricity Pricing Regime	Haiku Market Region	Auction	Grandfathering	Load-Based (population)	Load-Based (consumption)	Load-Based (emissions)
Competition	NEN	9.2	10.5	0.7	3.9	9.2
	NES	5.4	6.0	(3.6)	(0.6)	1.7
	NY	9.0	10.0	(2.0)	2.9	7.1
	NJD	6.4	7.0	(0.6)	1.6	5.3
	MD	8.4	9.9	0.8	3.3	4.7
	PA	10.6	12.1	4.6	4.6	0.8
	OHMI	10.1	11.5	3.4	3.4	1.4
	MAIN	9.7	10.6	3.6	3.6	3.5
	ERCOT	5.8	7.9	1.2	1.1	0.5
Regulation	FRCC	4.1	0.7	(2.6)	(2.5)	(1.1)
	AMGF	6.6	(0.2)	2.1	0.3	(0.2)
	VACAR	4.8	(0.4)	0.0	(1.8)	0.3
	KVWV	9.5	(9.3)	5.7	2.6	(4.1)
	IN	9.2	(7.4)	4.8	3.2	(3.3)
	ENTN	7.5	(1.1)	2.7	1.0	(0.7)
	SPP	8.0	0.2	3.6	1.5	(0.6)
	MAPP	7.9	(1.8)	2.7	1.8	(0.1)
	NWP	5.5	(0.1)	(2.3)	(2.7)	(0.6)
	RA	5.8	(1.7)	(2.9)	(1.4)	(4.2)
	CALN	1.8	2.6	(9.8)	(5.0)	2.0
	CALS	2.7	4.1	(7.5)	(2.6)	3.6
	RGGI	7.6	8.5	(1.4)	2.0	5.3
	Southeast	5.8	(0.3)	0.6	(0.8)	(0.3)
	Midwest and Appalachia	9.9	5.4	4.2	3.5	0.5
	Plains	7.1	3.1	2.3	1.5	0.0
	California	2.3	3.5	(8.5)	(3.6)	2.9
	Rockies and Northwest	5.7	(0.8)	(2.6)	(2.2)	(2.1)
	Competitive Regions	8.5	9.9	1.8	2.7	2.6
	Regulated Regions	6.1	(1.0)	(0.0)	(0.6)	(0.7)
	National	7.0	2.7	0.6	0.6	0.4

Appendix Table 2. Baseline Regional Characteristics in 2020

Electricity Pricing Regime	Haiku Market Region	Aggregate Region	Population	CO2 Emissions Rate (tons/MWh)	Electricity Consumption per Capita (MWh/person)	CO2 Emissions per Capita (tons/person)
Competition	NEN	RGGI	3,624,102	0.13	8.8	1.5
	NES	RGGI	11,685,426	0.44	9.1	3.8
	NY	RGGI	19,576,920	0.35	7.6	2.4
	NJD	RGGI	10,905,384	0.51	10.4	3.3
	MD	RGGI	6,497,626	0.68	10.3	5.1
	PA	Midwest and Appalachia	12,787,354	0.61	13.0	12.7
	OHMI	Midwest and Appalachia	21,998,225	0.85	13.2	11.1
	MAIN	Midwest and Appalachia	22,050,673	0.62	13.1	8.7
	ERCOT	Plains	25,040,400	0.63	15.0	9.7
Regulation	FRCC	Southeast	22,140,641	0.61	12.9	6.7
	AMGF	Southeast	19,883,364	0.62	17.9	12.2
	VACAR	Southeast	22,940,469	0.50	16.1	7.8
	KVWV	Midwest and Appalachia	6,976,401	1.01	21.6	27.2
	IN	Midwest and Appalachia	6,627,008	1.07	18.0	21.6
	ENTN	Southeast	15,470,035	0.68	17.0	13.5
	SPP	Plains	12,287,603	0.73	18.1	15.0
	MAPP	Plains	13,039,828	0.69	15.0	12.2
	NWP	Rockies and Northwest	18,976,707	0.34	14.2	6.6
	RA	Rockies and Northwest	18,902,845	0.67	10.7	9.8
	CALN	California	17,379,247	0.12	7.8	0.8
	CALS	California	24,827,496	0.21	7.5	0.7
		RGGI	52,289,458	0.42	8.9	3.2
		Southeast	80,434,509	0.60	15.8	9.7
		Midwest and Appalachia	70,439,660	0.79	14.4	13.2
		Plains	50,367,830	0.67	15.8	11.6
		California	42,206,743	0.16	7.6	0.7
		Rockies and Northwest	37,879,552	0.48	12.5	8.2
		Competitive Regions	134,166,109	0.61	11.8	7.5
		Regulated Regions	199,451,643	0.61	13.8	9.0
		National	333,617,752	0.61	13.0	8.4

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PRELIMINARY AND INCOMPLETE: PLEASE DO NOT CITE

When Does Cap-and-Trade Increase Regulated Firms' Profits?

David A. Evans, Ian Lange and Josh Linn

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Many recent studies have concluded that cap-and-trade programs for greenhouse gases with free allocation of permits would increase regulated firms' profits, chiefly for the electric power sector. It is likely that future greenhouse gas programs would induce reductions in abatement costs and the costs of generating electricity from low-emissions sources, such as wind power. Past research has not considered the effects of endogenous or subsidized cost reductions on incumbents' profits in detail, however. This paper investigates these effects and calculates the share of permits that would need to be grandfathered while keeping profits constant. A simple analytical model illustrates that technological change or subsidies to abatement equipment or renewables would likely decrease the profits of regulated firms. The simulation results of a detailed partial equilibrium model of the electric power sector confirm these conclusions and suggest that cost reductions are likely to decrease profits.

Keywords: Cap-and-Trade; Abatement Costs; Climate Change Policy; Compensation

JEL codes: Q58, Q40, Q52

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When Does Cap-and-Trade Increase Regulated Firms' Profits?

David A. Evans, Ian Lange and Josh Linn[ψ]

1 Introduction

As the policy debate over reducing greenhouse gas emissions has intensified, particular attention has been devoted to the effect of regulation on incumbent firms' profits. Numerous modeling studies predict that a carbon dioxide cap-and-trade program in the U.S. with 100% free allocation of permits would increase the profits of regulated firms, chiefly those firms in the electric power sector (e.g., Goulder and Bovenberg, 2001 and Burtraw *et al*., 2002). Evidence from the European Union's Emissions Trading System (EU ETS) for carbon dioxide (CO_2) appears to show that profits of electric power producers have increased (Sijm *et al*., 2006). The seemingly counter-intuitive result arises from the fact that a large share of the emissions reduction would be due to a reduction in output. With a relatively price-inelastic demand, the increase in revenue more than offsets the increase in costs provided that the right to emit is grandfathered to emitters.

Policy makers have responded to these results by proposing to auction a share of the permits to ensure that regulated firms' profits do not increase. For example, the European Parliament approved a post-2012 EU ETS with auctioned permits (100% in the electric power sector) in order to prevent the average profits of regulated firms from increasing.[1]

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[1] The auction revenue represents a transfer from the regulated firms to the government, provided that the auction revenues are not refunded to the affected firms. The regulator can control total emissions by setting the cap, and can influence the effect of the regulation on profits through the fraction of permits it provides freely.

The modeling studies cited above are essentially static in nature, however. In particular, they do not consider the effect of cap-and-trade programs on costs, which in turn affect incumbents' profits. For two reasons, it is highly likely that cap-and-trade programs for greenhouse gases cause reductions in the cost of abatement technologies and in the cost generation technologies with low emission rates, such as renewables. First, there is considerable evidence that cap-and-trade programs cause innovation and technology adoption (e.g., Popp, 2002, Bellas and Lange, 2005 and Linn, 2008). Regulation-induced innovation and technology adoption could reduce the cost of abatement technologies, such as carbon capture and storage (CCS), and the cost of renewable energy sources, such as wind and solar. Second, in recent CO_2 cap-and-trade programs and proposals for future programs, a share of the auction revenue is used to directly subsidize abatement technology and renewables generation. Similarly to the effect of regulation-induced technological change, these subsidies and research programs would reduce abatement costs and the cost of producing electricity from renewable sources.[2] Understanding the effect of cap-and-trade on profits therefore requires a more flexible approach that accounts for endogenous reductions in costs or reductions in cost attributable to direct incentives associated with the cap-and-trade program.

This paper provides a framework for understanding how cap-and-trade programs affect profits in a dynamic setting. Our analysis is strictly positive in nature; we are interested in how the value of existing capital may change as result of policy-induced reductions in the cost of lowering emissions intensity. We are not making claims that additional compensation is required of firms affected by a cap-and-trade policy, although the analysis may inform the political economy surrounding the debate regarding the level and appropriate form of legislation and regulation to control greenhouse gases.

[2] The two uses of auction revenues differ in their desirability from the perspective of economic efficiency. If there is a market failure in that investment in research and development is undersupplied, then using auction revenues to support this research may be welfare-improving. However, unless the direct subsidy to renewable production allows these technologies to overcome some other market failure, then using the auction revenues in this manner is inefficient.

We first use a simple analytical model in which firms can reduce total emissions under a cap-and-trade program by reducing output or by using direct abatement technology to reduce the average rate of emissions per unit of output. Direct abatement technologies include those controls that can be retrofit to an existing facility or added to a new facility to reduce the emission rate. We show that if additional direct abatement is more costly, i.e. the rate at which the marginal direct abatement cost increases is higher, the greater is the reduction in output and consequently the increase in revenues. On net, provided that a sufficient number of allowances are grandfathered to emitters, the regulated firms are better off. Alternatively, considering an increase in regulatory stringency – a decrease in the cap – the greater is the magnitude of the elasticity of total output to emissions; the greater is the increase in profits. Several numerical examples illustrate the main intuition and provide insight into the likely effect of decreasing costs on the profits of incumbent firms. The main predictions are, first, that a decrease in the cost of direct abatement technologies, either because of regulation-induced technological change or subsidy, may reduce profits if firms are less likely to reduce output. Second, decreases in the cost of low-emission generation sources are also likely to reduce profits because they decrease the elasticity of total output to emissions.

These predictions are confirmed by simulations of a detailed market model of the U.S. electricity sector. The baseline simulation reproduces the findings of the previous literature that a carbon dioxide cap-and-trade program increases profits. However, we also find that profits are increasing in the elasticity of output to emissions. Moreover, the effect of abatement costs and the costs of renewables on profits is quantitatively large, implying that endogenous cost reductions are likely to have a significant effect on profits. The paper concludes by discussing the implications of these results for auction design. In particular, using auction revenue to subsidize new abatement technology or renewables substantially reduces the profits of existing generating units.

2 Background

This section briefly summarizes firms' compliance behavior in cap-and-trade programs, which is modeled more formally below, and summarizes the recent literature. The imposition of a cap-

and-trade program leaves firms in the regulated industry with essentially two compliance options: reduce output or reduce the rate of emissions per unit of output. The emissions rate can be reduced by switching to a cleaner fuel, such as substituting natural gas for coal, or by installing abatement equipment, such as carbon capture and storage (CCS). Regulated firms in a competitive market choose the profit-maximizing compliance behavior, based on the output price and permit price; the output price represents the cost of reducing output and the permit price represents the benefit of reducing output as well as the benefit of reducing the emission rate. If firms primarily respond to the regulation by reducing output and the demand curve for output is relatively inelastic (as in the case of electricity), then the regulation causes profits to increase. In this case the the limit on emissions acts as a limit on output and firms behave similarly to a cooperative oligopoly in which firms restrict output to increase profits (Mansur, 2007).

The other option is to reduce the rate of emissions per unit of output, either by installing abatement equipment or by switching to fuels with low emission rates. In this paper, direct abatement refers to a reduction in the emission rate obtained by installing capital equipment such as CCS. Fuel switching under a cap-and-trade program is more costly when the price of permits is arbitraged into the price of the cleaner fuels (Keohane and Busse, 2007). If firms comply entirely by reducing their emissions per unit of output, profits must decrease because production costs increase and there is no effect on the output market. Therefore, whether firms abate by reducing output or reducing the emission rate influences the effect of a cap-and-trade program on profits.

The incentive for firms to choose a decrease in output versus a decrease in the emissions rate depends crucially on the availability of low-cost direct abatement technology and low-emissions generating entrants. These two factors essentially decrease the elasticity of abatement costs with respect to (w.r.t) output. If the elasticity is high, this can be interpreted as a case where emissions and output can be unattached and the cap-and-trade program will no longer act as an output constraint. If the elasticity is low, emissions and output are attached and the cap-and-trade program will act as an output constraint allowing firms to reduce production, increase prices and profits.

Many potential greenhouse gas policies include substantial auctioning of permits with plans to use the auction revenue to subsidize direct abatement technology (e.g., CCS) and low-emissions generating entrants (e.g., renewables).[3] The post-2012 EU ETS calls for full auctioning in the electricity sector in 2012 and full auctioning in other sectors by 2020. The auction revenues will be used to fund CCS demonstration projects and renewable technologies. Every recent greenhouse gas legislative proposal in the 110th US Congress called for some auctioning of emissions allowances, while a share of allowances is provided to incumbent emitters in part to keep their profits "whole" in the face of the cap. For example, the Lieberman-Warner Climate Security Act specifies that 21% of permits be auctioned in 2012, increasing to 69% in 2031 and staying at 69% until 2050. Approximately 13% and 18% of auction proceeds would be used to subsidize renewable energy (Title IV-Subtitle D-Section 4406) and research into sequestration technology (Title IV-Subtitle D-Section 4403), respectively. The Regional Greenhouse Gas Initiative, a cap-and-trade program in the Northeast, requires that 25% of permits be auctioned and the proceeds used to fund investment in energy efficiency or low-emissions generation. The states can decide how to allocate the remaining 75%, although most states have announced they will auction off a large percentage of their permits.

Maloney and McCormick (1982) first explore the possibility that environmental regulations may cause firms to reduce production, which would increase the output price and perhaps profits. They note the importance of free allocation and entry costs in determining the effect of regulation on profits.

Dinan (2003) provides a broad overview of the literature related to firm and consumer compensation with the imposition of a cap-and-trade regulation. Goulder and Bovenberg (2001) use a general equilibrium model of the U.S. to determine the percentage of allowances that should be grandfathered (i.e., allocated freely to existing units) to hold profits constant under an economy-wide cap-and-trade program for carbon dioxide (CO_2). They conclude that for many sectors, especially electricity and fossil fuel, full grandfathering would increase profits, so that less than 100 percent of the permits should be grandfathered to leave profits unaffected.

[3] Other compelling reasons for auctioning abound. For a survey of these arguments, see Burtraw and Evans (2008).

Cameron *et al*. (2006) uses a Cournot model to determine the percentage of grandfathered permits needed to hold industry profits constant under a CO_2 program. Using UK and European industry data for electricity, cement, steel, and newspaper generation, they find that these industries require no more than 65% of permits to be grandfathered to ensure that the industries' profits are constant; the electricity industry requires no more than 6%. Burtraw and Palmer (2007) use a detailed partial equilibrium model of the US electricity sector to compare alternative allocation methods.[4] Results show that grandfathering permits to electricity generators leaves virtually all of them better off and the largest firms substantially better off.

The conclusion that the imposition of a cap-and-trade program may lead to increased profits is not limited to carbon dioxide. Burtraw and Palmer (2003, 2004) show that grandfathering allowances under cap-and-trade programs for sulfur dioxide, nitrogen oxides and mercury would also lead to an increase in total profits for the electricity sector. Parry (2004) addresses a similar question from a different perspective, focusing on the effect of cap-and-trade programs on household wealth. For small reductions in emissions, households in the top wealth quintile, who are most likely to own shares of firms affected by the regulation, are made better off with the introduction of emissions caps on sulfur dioxide, nitrogen oxides and carbon dioxide when allowances are fully grandfathered. Parry (2004) uses an aggregated partial equilibrium model of the US electricity sector with a linear marginal abatement cost function and argues that a convex function would exacerbate the regressivity of permits. Mansur (2007) uses the imposition of a tradable permit scheme for nitrogen oxides (NO_x SIP Call) to show that firms reduced output more than in a competitive market in an effort to raise prices.

While many models of the effect of potential greenhouse gas legislation on firms' profits find they will be overcompensated, other modeling (Farrell *et al*., 1999) and empirical (Linn, 2006)

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[4] Burtraw and Palmer (2007) and Burtraw *et.al* (2002) are part of a series of studies that look at the effect of different allocation schemes for cap-and-trade programs in the electricity sector on producer and consumer surplus using the model used in this paper. Generally they find that incumbent firms prefer grandfathering, followed by auctioning of allowances and finally allocating allowances based on recent production levels (output-based updating) regardless of the pollutant being regulated. Furthermore, all of the allocation methods yield to higher total profits for all firms in the industry (although some a are certainly worse off). In part this is due to the nature in which electricity is priced, as described below.

studies of cap-and-trade programs for conventional pollutants have found that these programs reduce profits of affected firms. Farrell *et al*. (1999) uses a detailed partial equilibrium model of the US electricity sector to investigate the effect of a cap-and-trade program for nitrogen oxides. Linn (2006) finds that the stock prices of regulated firms decreased in anticipation of a regional cap-and-trade program for nitrogen oxides.

3 The Relationship Between Profits, Abatement Costs, Entry Costs and Baseline Emissions

3.1 Increasing Profits with a Cap-and-Trade Program

We begin by demonstrating the possibility that profits can increase with the imposition of a cap-and-trade program. The analysis focuses on a representative firm. Let *q* be the total production/consumption of the output in the market subject to the cap and trade regulation. Uncontrolled emissions equal q*z, where z is the uncontrolled emissions per unit of *q* (i.e., the emissions intensity of q), while actual emission are represented by *e*. Abatement is then $a \equiv qz - e$. The abatement technology is represented by the cost function: $f(qz-e)$, where $f'(qz-e) \geq 0$ and $f''(qz-e) \geq 0$. Marginal-willingness to pay for output is represented by *P(q)* while the cost of producing *q* net of emissions control costs is *C(q)* and these functions are assumed to have the usual shape ($P'(q) \leq 0$, $C'(q) \geq 0$, and $C''(q) \geq 0$).

Each firm in this market is subject to an emissions cap represented by *A*, so that compliance requires that $A \geq e$. We assume that the regulated firms do not have market power, and therefore take the output price, *P*, as given. The profit maximization for the firm is:

$$\max_{q,e} \ \pi \equiv Pq - C(q) - f(zq-e) \qquad \text{s.t.} \quad A \geq e \tag{1}$$

The first order conditions of this problem (assuming the allowance constraint binds) are:

$$P - C'(q) - zf'(zq-e) = 0$$
$$f'(zq-e) - \lambda = 0$$
$$A - e = 0$$

where λ is the shadow value on the emission constraint and is therefore the permit price.

The effect on profits of tightening the cap (i.e. reducing *A*,) depends on how *A* affects production, emissions and the allowance price. After substituting *P=P(q)* in the first order conditions, it can be shown that:

$$\frac{dq}{dA} = \frac{zf''(qz-e)}{SOC} \geq 0$$
$$\frac{de}{dA} = 1$$
$$\frac{d\lambda}{dA} = \frac{[P'(q) - C''(q)]f''(qz-e)}{SOC} \leq 0$$

where $SOC = -P'(q) + C''(q) + z^2 f''(qz-e) \geq 0$ and is the second-order condition of equation (1). The first equation shows that the production of *q* increases as the cap is loosened. Critical to the hypothesis being explored here, the increase in production from an increase in the cap is larger if the rate of increase in the cost of directly controlling emissions rises (i.e., notionally $dq^2 / dAdf''(.) \geq 0$). Production is more responsive to the level of allowable emissions if direct emissions control is more expensive. Therefore, we see that the reduction in production is greater if *A* decreases and direct abatement is increasingly costly. The second and third equations show that, unsurprisingly, emissions rise in proportion to *A*, and the allowance price falls with *A*.

Total profits to the industry can be expressed as:

(2) $$\Pi \equiv P(q)q - C(q) - f(zq-e) - \lambda(1-s)A$$

The expression $\lambda(1-s)A$ represents the value of the allowance rent that the government retains where the share of grandfathered allowances to emitters is *s*. The expression can be thought of as the total payment paid by the industry to purchase the share of the allowances that is auctioned.[5] This term was not included in the exercise above because we assume that firms take the allowance price as given (also note that if *s*=1 the regulated firms capture the entire scarcity rent of the cap). Therefore, profits equal industry revenues minus production, abatement costs, and the share of the scarcity rent from the allowances that is not allocated to industry.

Taking the total derivative of (2) with respect to the cap, we can demonstrate the ambiguity of industry profits to a decline in the cap. Applying the profit maximization relationship that price equals marginal production cost, and that the cap binds such that the change in allocation equals the change in the cap, we obtain:

(3) $$-\frac{d\Pi}{dA} \equiv \underbrace{-\left[P'(q)q\right]\frac{dq}{dA}}_{(+)} \underbrace{-s\lambda\frac{de}{dA}}_{(-)} \underbrace{+A(1-s)\frac{d\lambda}{dA}}_{(-)}$$

The first term of this expression shows that profits increase from reducing the cap due to the contraction of production that in turn raises inframarginal revenues.[6] The more responsive demand is to a change in production (i.e, the bigger the absolute value of $P'(q)$), the greater is this first term. The second term captures the decrease in the value of the allowances allocated to firms as a result of the cap being smaller. As the cap falls, the allowance price will also rise, and these additional allowances must be purchased from the government. This effect is represented by the last term in (3). If all allowances were allocated freely (*s*=1), then the entire expression would simply equal the change in inframarginal revenues from tightening the cap minus the

[5] We are assuming that the method of auctioning allowances yields an allowance price that equals the shadow value of the allowance constraint.

[6] This expression would not be present in the case of regulating a monopolist. This is because the monopolist is already accounting for the inframarginal change in revenues as supply is contracted. If the supply side of the market were characterized by monopoly pricing, then the amount of compensation required to keep profits neutral will be higher than if the market is characterized by marginal cost pricing.

marginal cost of the direct control technology.[7] If *s*=1, it is straightforward to show that if the marginal cost of the direct control technology is increasing rapidly ($f''(.)$ is large), then firms are made better off by tightening the cap.

3.2 Extending the Model to Multiple Producer Types

The preceding analysis provides important intuition, and this section extends the analysis to include two important features of electricity markets: heterogeneous producers with different uncontrolled emission rates. It is assumed that there is marginal cost pricing and particular functional forms are chosen for electricity demand, generation costs, and the direct abatement cost function. There are two types of electric generating units, which have different fixed and marginal costs, where all fixed costs are assumed to be entirely sunk. Base load units, denoted with the subscript b, have relatively high fixed costs, and low marginal generating costs, equal to mc_b. Peaking units have lower fixed costs but higher marginal costs of $mc_p > mc_b$. Each base load unit has a maximum generating capacity of $\overline{q}_b$ and each peaking unit has a maximum generating capacity of $\overline{q}_p$. There are n_b and n_p base load and peaking units in the market, meaning that they have all paid their sunk costs. The electricity market is competitive, and each unit operates at full capacity as long as the price exceeds its marginal operating costs.[8] The demand curve for electricity has a constant elasticity of substitution (CES), and is given by:

$$P = \gamma(n_b q_b + n_p q_p)^{1/\delta},$$

where γ and δ are constants and q_b and q_p equal the output of each base load and peaking unit; δ is the own-price elasticity of demand.

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[7] Note that the change in profits from lowering the allocation is linear in *s*. As *s* increases the previously grandfathered allowances have a bigger influence on the change in the value of those allowances. However, the effect of the higher allowance price on the share that must be purchased from the government declines.

[8] In this model, high and low cost units operate in a competitive market and we abstract from time-varying electricity demand.

Figure 1 illustrates the market equilibrium. The supply curve is horizontal at mc_b until all base load units are operating at full capacity, at which point the supply curve is horizontal at mc_p. The supply curve is vertical when peaking units are also operating at full capacity. The figure shows the long run equilibrium, where all units earn zero profits. Price exceeds marginal costs for all units, and operating revenue exactly covers fixed costs (recall that the base load units have higher fixed costs).

Starting from long run equilibrium, the government unexpectedly announces that there will be a cap-and-trade program for carbon dioxide emissions. The cap is set at C and permits are grandfathered. Peaking units have zero emissions, while base load units have uncontrolled emission rates of $z > 0$. However, base load units may reduce their emissions according to the function:

$$x = f(qz - e) = \alpha(qz - e)^{\beta},$$

where α and β are positive constants, with $\beta > 1$. The variable x equals abatement expenditure and e is the unit's emissions. The abatement cost function has positive and increasing marginal abatement costs, and the elasticity of emissions with respect to abatement expenditure is constant.

Base load units are price-takers in both the electricity and permit markets. They choose the profit-maximizing level of output and abatement expenditure. Under the cap-and-trade program, they must hold enough permits to cover their emissions. Their optimization problem is given by:

$$\max_{q_b, x_b} q_b(p - mc_b) - f(qz - e) - \pi(zq_b - (x/\alpha)^{1/\beta} - a_b)$$

$$s.t. q_b \le \overline{q}_b,$$

where π is the equilibrium permit price and a_b is the number of permits allocated to the unit. The first order condition for output is:

$$p - mc_b - \pi z - \mu = 0,$$

where μ is the multiplier on the production constraint. The marginal operating cost of the base load unit now includes the marginal cost of generating electricity, plus the product of the permit price and the uncontrolled emission rate. The first order condition illustrates a central result: as long as the permit price is sufficiently low, the constraint binds and base load generating units operate at full capacity. However, high permit prices may cause the base load units to reduce their output below full capacity.

The optimization problem of a peaking unit is similar, except for the fact that peaking units have zero emissions and therefore do not choose abatement.

$$\max_{q_p} q_p(p - mc_p) + a_p \pi$$

$$s.t. q_p \leq \overline{q}_p$$

Because peaking units have zero emissions, the permit price does not appear in their first order condition. As a result, peaking units always operate at full capacity.[9] The equilibrium electricity and permit prices, as well as the effect of the cap on profits, depend on the cap and other parameter values. The following subsections investigate the effect on generating units' profits of the cap and the elasticity of abatement costs.

3.2.1 Effect of the cap on profits

[9] The assumption that peaking units have zero emissions is for simplicity, however, and does not affect the main results.

Figures 2a and 2b show how the equilibrium varies with the emissions cap, A, for particular parameter values. In both figures, the horizontal axis shows the required abatement under the cap, which is equal to the difference between unregulated emissions and A. The figures show as functions of total abatement the equilibrium output and abatement expenditure of base load units; and the permit price, electricity price and total industry output. The figures correspond to the short run equilibrium, in which entry of new generating units is not possible.[10]

Figure 2a shows that as total abatement increases from zero, abatement expenditure and the permit price increase. However, the permit price never becomes sufficiently high that base load units reduce output (base load generating capacity is set equal to 4 in these simulations). Figure 2b shows that as total abatement increases, industry profits decrease. The reason is that under this set of parameter values, increasing total abatement (i.e., decreasing A) does not affect the electricity market, as all generating units continue to operate at full capacity; as the figure shows, the price of electricity does not change with the cap. As total abatement increases, however, base load units must increase their abatement expenditure to reduce emissions sufficiently to meet the cap, which reduces profits. Note that although permits are allocated freely to generating units, total profits are lower than if there were no cap. We next show that this result arises because regulation does not affect the equilibrium level of electricity production. That is, profits decrease when output and emissions are uncorrelated in equilibrium.

3.2.2 Effect of the abatement function on profits

We now demonstrate one of the main results of this section: as abatement becomes more costly, profits may increase. Subsequently, we will interpret this result in the context of recent policy proposals to support innovation in abatement technologies, which would reduce their costs. For the simulations, total abatement is fixed at 50. The value of β varies from 1 (the value used in

[10] Focusing on the short run simplifies the exposition, but allowing for long run entry would not significantly affect the main conclusions.

Figure 2) up to 5. Figures 3a and 3b plot as functions of β the equilibrium output and abatement expenditure of base load units; and the permit price, electricity price and total industry output. An increase in β represents an increase in the elasticity of abatement costs w.r.t output. That is, higher values of β reflect more costly abatement.

For low and moderate values of β , increasing the elasticity of abatement costs operates similarly to an increase in total abatement, which was shown in Figure 2. When the elasticity increases, for a given A, abatement expenditure increases and the permit price increases. Electricity production is not affected, and profits decrease.

A striking change occurs when β is greater than about 3: an increase in β causes industry profits to increase, even though abatement is more expensive. The first order condition for base load output provides the intuition. For low values of β, the permit price is low and the output price exceeds the marginal operating cost for base load units, which therefore operate at full capacity. As β increases, however, the permit price increases as well, and at some point the price of electricity no longer exceeds marginal operating costs. Therefore, base load plants reduce output, which causes the electricity price to rise. There are therefore two effects of increasing β, while holding A constant. The first is that abatement costs increase, which reduces profits. On the other hand, electricity production also decreases, which increases profits because electricity demand is price-inelastic. Under the particular parameter values chosen for these simulations, the second effect is greater in magnitude, and an increase in β leads to higher profits when β is sufficiently large. Note that when β exceeds 3, total industry profits are greater than when there is no cap on emissions; this case is commonly referred to as overcompensation.

In the extreme case where base load units cannot reduce their emissions rates at all, which is roughly the case for carbon dioxide regulation, all abatement occurs via curtailing base load generation. That is, all abatement occurs via fuel switching, in which the share of generation of high-marginal cost peaking units increases at the expense of base load units. In this case, even a very large A could significantly increase firms' profits. On the other hand, when abatement is

relatively inexpensive, as with nitrogen oxides or sulfur dioxide, there is likely to be a much smaller effect on electricity production, and a small or moderate cap may decrease profits.

3.2.3 Entry of Zero Emission Rate Generating Units

We now discuss the effect of the entry of generating units with zero emission rates, such as wind or solar, which will be referred to as renewable generating units. It is assumed that the renewable technology has fixed costs of F_r, zero marginal costs and a maximum generating capacity of $\overline{q}_r$; renewable generators enter as long as the output price exceeds $F_r / \overline{q}_r$. There is an unlimited number of renewable generating units that could potentially enter the market. Therefore, once the cap-and-trade program is implemented, renewable generators will enter the market until the output price equals $F_r / \overline{q}_r$. That is, the renewable technology amounts to a cap on the price of electricity.

In practice, F_r might decrease because of technological change or because of government subsidies (e.g., an investment tax credit). The first case to consider is the one in which the capacity constraint does not bind. A decrease in F_r reduces the price of output and profits unambiguously fall. The more interesting case is hen the capacity constraint does not bind, i.e., as in the right section of Figure 3.

For this case, Figure 4 plots the equilibrium outcomes as functions of the price of electricity. That is, as F_r decreases, the electricity price decreases, moving from right to left in the diagram. The simulations use the baseline parameter values from Figure 3, setting $\beta = 5$, and varying F_r. In the diagram, the minimum price is the price of electricity if there were no cap-and-trade program, and the maximum price is the price from Figure 3 when $\beta = 5$.

Consider first the case in which F_r is sufficiently high that there is no entry of renewable in equilibrium. As Figure 3 shows, base load units comply with the cap by abatement expenditure and reducing output. The output constraint does not bind and the price of electricity exactly

equals operating costs $mc_b + \pi z$ .Now consider a decrease in F_r large enough that renewable units enter the market. The price of output decreases, but the permit price must also decrease so that the first order condition for base load output continues to be satisfied. Therefore, abatement expenditure decreases. To comply with the cap, base load units must decrease output. Thus, there are two effects on industry output. Base load units decrease production while renewable units increase production. The latter effect is greater in magnitude, so the output price falls and industry profits decrease.

Recall that the simulations reported in Figures 2-4 assume that there is no entry of base load or peaking units. The results in Figure 4 indicate that allowing for such entry generally offsets any increase in profits, to the extent that entering units have a lower emission rate than the average unit.

3.2.4 Emissions Rates of Peaking Units

One of the reasons for distinguishing base load and peaking units is that we can investigate the importance of relative (uncontrolled) emission rates of the two classes of units. Figure 5 shows the effect of increasing the emission rate of peaking units from the baseline value of zero to 0.4. It is assumed that the direct abatement technology is not available to peaking units, so that they cannot reduce their emission rate. This assumption which seems reasonable given that abatement technology is typically characterized by having high fixed costs and low marginal costs; i.e., peaking units will not generally find it optimal to install abatement equipment even when base load units do install such equipment.

Intuitively, increasing the emission rate of peaking units amounts to increasing total abatement or decreasing the cap. Figure 5 shows that for low emission rates of peaking units, increasing the emission rate has the same effect as increasing total abatement, which was depicted in Figure 2. Base load units comply by reducing their emission rate instead of decreasing output, which leaves the output price unaffected and decreases profits.

When the emission rate of peaking units increases above about 0.1, the permit price is sufficiently high that base load units reduce output in addition to reducing their emission rate. As a result, the output price and profits increase, and the cap-and-trade program results in greater profits.[11]

3.3 Summary of Modeling Results

The numerical results suggest that the greater the reduction in total industry output, the greater are profits. That is, the greater the (negative) elasticity of output to emissions, the greater the effect on profits. Therefore, a reduction in abatement costs may decrease profits because firms are less likely to reduce output in response to a cap. Greater entry of renewables or a reduction in emissions rates of non-base load units would have a similar effect. The next section shows that these results hold in a detailed model of the electric power sector and quantifies the magnitude of these effects.

4 Demonstrating the Importance of Abatement Opportunities using a Detailed Electricity-Sector Model

4.1 Model Setup

The previous discussion describes the relationship between the availability of techniques to reduce emissions intensity, either through direct abatement or cleaner technologies, and the elasticity of demand on the profits of incumbents. In particular, we see how the availability of cleaner technologies impacts the profits of incumbent firms qualitatively. What is not yet clear is how sensitive forecasts of the change in firm profits as a result of a particular policy are to

[11] This result implies that if Figure 2 were extended to show the effect of greater total abatement, there would be a similar inflection point, when base load units begin restricting output and profits begin to increase. Furthermore, if the emission rate of peaking units becomes sufficiently high, they may begin to reduce output. This causes profits to increase at an even greater rate.

assumptions about critical parameters discussed in the previous section. To address this issue we use a detailed partial equilibrium model of the U.S. electricity sector to explore how incumbents' profits are affected by a reduction in the cost of renewable generation in the presence of a CO_2 emissions cap. We use the Haiku electricity sector model developed at Resources for the Future (Paul et al, 2008). Future work will use the model to show the affect on profits from changes in direct abatement costs and the emission rate of non-base load units under a climate policy.

While we will identify reasonable bounds of the induced reduction in the cost of wind generation in forthcoming analysis, the analysis reported herein is intended to demonstrate the influence of the cost of abating and relatively clean new production technology in the abstract. That is, we are not claiming that our different cost sensitivities fall into bounds that are empirically informed, and therefore are knowingly relevant for policy. However, if a significant effect on profits cannot be shown at the extremes considered in this analysis, then they presumably would not be important within a policy-relevant range. Also, as discussed below, we model policy-directed reductions in the cost of wind generation relative to incumbent generators. In the Lieberman-Warner climate proposal 4% of annual auction revenues are set aside to subsidize renewable generation. While it requires some assumptions about exactly how exactly these allowances will be distributed, we model the effect of this use of auction revenues on the profit of incumbent generators. Therefore, this portion of the analysis can be viewed as empirically informed.[12]

The Haiku electricity market model has been used primarily to study national and regional environmental and market structure policies that affect this sector. Haiku solves via an iterative tâtonnement algorithm in the prices for both electricity production and major fuel inputs,

[12] In both of these cases other potentially important sources of relative cost changes are admittedly being ignored. We recognize that the source of any reduction in the cost of new wind generation may spillover or be applicable to other generating technologies (e.g., a general improvement in the cost of turbine production). However, these effects may only exacerbate the effect of induced innovation on the profits of incumbent generators. We also note that other uses of the asset value of allowances, such as provisions for bonus allowances for adopting facilities with carbon capture and storage, may also influence the profitability of incumbent firms. However, we can not exhaustively consider all of the possible direct uses of auction revenues that may meaningfully influence the relative costs of generation and pollution control in the electricity industry.

including coal and natural gas, as well as the price of emissions allowances. Welfare includes both consumer and producer surplus in the electricity market adjusted by any changes in government revenues. The model allows for dynamic investment and compliance behavior. For the purposes of this study the model is solved for five evenly-spaced simulation years over a 20-year time horizon.

The model divides the contiguous states of the U.S. into 21 regional electricity markets roughly defined by historical regional electricity reliability council boundaries, plus some further spatial disaggregation. Electricity demand is price responsive and distinguished by consumer class (residential, industrial, commercial), season (summer, winter, spring/fall), and time of day (base load, shoulder, peak, and super-peak); there are 756 distinct retail electricity markets in each simulation year. Interregional trade is modeled endogenously subject to transmission capacity constraints between regions. The wholesale electricity market is assumed to be competitive so that prices are based on the relationship between marginal generating costs in different regions. Each of the 21 regional retail markets can be characterized by either average (cost-of-service) or marginal cost pricing.[13] Whether a region is treated as an average cost or marginal cost pricing region depends on the pricing structure faced by the majority of consumers in that region.

Electricity generators are represented by "model plants" defined by nine criteria: location, vintage (existing or new), prime mover, fuel, relative operating cost (for those generators using natural gas or nuclear fuel), and, for coal-fired boilers, coal demand region, capacity, and the expected presence of SO_2 and NO_X post-combustion abatement controls in 2010. Generator dispatch at any time is determined by a model plant's short-run operating cost. Capital stock investment and retirement, as well as investment in pollution control technologies, are determined by the expected profitability of generation assets over time. Assumptions regarding the performance of new generation capacity and pollution control technologies are drawn from a variety of sources.

[13] Marginal cost pricing refers to "average marginal costs" over time blocks in a particular season, as opposed to time-of-day pricing.

The possibility that firms are subject to average-cost pricing adds an additional nuance to the analysis that is not captured in the simple model in the previous section. Emissions allowances in average-cost pricing regions are assumed to be treated in the rate base at their original costs, i.e. zero. If the entire market is characterized by average cost pricing it is assumed that full grandfathering allowances will have no direct effect on the output price (Burtraw et al, 2002). Furthermore, auctioning allowances has been shown to increase welfare relative to grandfathering allowances because average-cost pricing causes the price of electricity to differ from marginal generating costs, auctioning increases total welfare by reducing the difference. In a perfectly competitive markets this would not be the case; total welfare would be the same with both auctioning and grandfathering and the only difference would be the wealth transfer between the government and the regulated firms.[14] That all said, the focus of our analysis is on the profits of incumbent firms in deregulated regions. While a plant in a cost-of-service region may earn profits, the firm that owns that plant may not. On net, the model requires that the net return on all assets in the regulated regions are zero but for the covering the cost of capital.

The Haiku model has been used in other studies exploring different dimensions of the question of the effect of cap-and-trade programs on the profits of incumbent firms, including the composition of the portfolio of generating technologies of firms and the method of allocation allowances (Burtraw et al. 2002, Burtraw and Palmer, 2007). Furthermore, outputs from this model have been used to calibrate more aggregate models of the electricity sector used in the literature on the incidence of environmental regulations (Parry, 2004 and Bovenberg *et al*. 2005).

The emissions cap used in this analysis mimics the required economy-wide percentage emissions reduction in the early simulation periods (through 2020) required by the Lieberman-Warner Climate Security Act of 2007, but then is about 25% tighter than the Lieberman-Warner restrictions in the later periods. However, there are important differences between the cap we model and the recent economy-wide caps that are the foundation of recent legislative proposals. One of the differences is obvious: that we are using a sector specific approach which may over

[14] Subject to the caveat that the receiving grandfathered allowances is not conditional on operating the plant, so that there is no distortion in the entry/exit decisions of affected firms.

estimate any allowance price effects from changes in the cost of abatement in the electricity sector as other sectors of the economy may absorb emissions or provide reductions. Another difference is that we do not allow emissions banking for carbon emissions for modeling convenience. However, we pick an allowance cap path intended to mimic a Hotelling-price path for allowances.

4.2 The Cost of Renewable Generation on Incumbent's Profits

In this experiment we explore how the profits of incumbent firms under a national emissions cap on CO_2 are influenced by the capital and operating cost of new wind generators.[15] The cost and maximum potential capacity of new wind generators in Haiku is drawn from the EIA's NEMS model. For each region the total available wind capacity is divided into five capital cost "bins". The cost of installing wind capacity is 20%, 50%, 100% and 200% for each cost step relative to the first step and the bins are not of equal size. The accelerating cost of adding new wind capacity is meant to reflect the decline in the suitability of sites (due to terrain, distance from the grid, etc.) to install new wind turbines.[16] Under the two cost sensitivities, each capital cost "step" is decreased by 30% or 50%. The 30% cost reduction was chosen because this is roughly the per MW value of the subsidy paid to renewable generators under a 20% renewable portfolio standard policy in 2020 using Haiku, and therefore the results may be roughly compared to that analysis (Blair et al., 2009). The 50% cost sensitivity was chosen because it is likely a lower bound on the possible reduction in cost. Both of these cost reductions are assumed to occur immediately after the policy is adopted.[17]

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[15] While it is possible for existing plants to improve their efficiency and therefore emissions per unit of production, Haiku does not model this possibility due to a lack of information on the cost and effectiveness of these efficiency improvements.

[16] All of the assumptions about the cost, availability and performance of wind in Haiku are adopted from the version of Energy Information Administration's (EIA) National Energy Modeling System used for the Annual Energy Outlook 2008.

[17] Future work will consider the possibility of a gradual or future reduction in costs, which seems more likely, and perhaps also less apt to influence incumbent firm profits because these cost reductions will occur after their meaningful life.

When the cost of a new generating technology is changed in the model it would affect both conditions in the policy scenario and conditions in the baseline. That is, the introduction of less expensive wind would outcompete at least some existing generation regardless of whether or not a policy is in place. For this reason, existing sensitivity analyses consider cost changes in both the baseline and in the policy case. While our interest is in situations where costs may differ between the baseline and the policy, we also model the case where wind cost are lower absent the policy to identify what portion of the affect on profits is attributable to the lower cost of new wind generation and what is attributable to the policy. The comparison between the profits in case with and without the policy with different assumed wind costs is independently informative. As explained in further below, the metric we use to measure the change in incumbent firm profits is as a share of auction revenues. Few existing analyses report the sensitivity of this statistic to model assumptions, with Bovenberg et al. 2005 being a notable exception.

As described above we also look at the case where a share of the auction revenue is provided to new wind generation. We consider two levels. In the first, 4% of the auction revenue is provided to new wind generation (built after 2010) in the form of a subsidy per kWh generated. As discussed above, under the Lieberman-Warner proposal 4% of the auction revenue is to support renewable generation, although the bill is not explicit about the form of the support, although we think it is reasonable to assume that it would be in the form of a production subsidy.[18] Also, under the Lieberman-Warner proposal the share of auction revenues allocated to renewables is based on an economy-wide cap, whereas we are only modeling a sector specific cap. For this reason, we consider the case where 10% of the auction revenue is provided to wind generators. We chose 10% because the electricity sector comprises approximately 40% of U.S. greenhouse gas emissions.[19] Of course, this share has a larger effect on the allowance price than would occur

[18] We retain the native assumption in Haiku that wind receives the 1.9 cent/kWh (2005$) tax credit as provided by the Energy Policy Act of 2005. The tax credit is earned on generation in the first 10 years of operation of a facility. The credit is discounted to 90% to reflect the fact that over time it has lapsed on previous occasions, but not for long spells since it was originally introduced in 1992. It might be argued that the allocation of allowances to wind energy will be treated as a replacement for the tax credit on wind energy, which must be renewed.

[19] Although, because of the availability of relatively low cost controls in the electricity sector, it is forecast to emit an even lower share of emissions under a cap-and-trade program.

under an economy-wide cap, but one can view the effect of the 4% and 10% cases as roughly bounding the effect that would occur had we modeled and economy-wide program. Another notable difference is that unlike the Lieberman-Warner approach where the share of allowances allocated to renewables falls to 1% in 2031, we assume that wind receives a 4% or 10% share indefinitely in that the terminal year of our analysis, 2030, is modeled to represent all future periods.

We deviate from an important native assumption in Haiku, which is to restrict the total amount of new construction of wind generation to a certain percentage of existing capacity in the region. For some regions these constraints bind, although without much consequence, in the baseline case. We remove them because as we move to lower wind costs under the policy case, they bind further and the consequence of less expensive wind no longer has a marginal effect on electricity prices and composition of fuels used to generate electricity (the cost steps described above have a similar effect as we will see).

Table 1 summarizes the change in the national electricity price, which is a simple consumption-weighted index of prices in all regional markets, the allowance price and the CO_2 emissions level under the different policy and wind cost scenarios. The cap is binding with 100% wind costs in all years where there is a cap, but that is not the case with lower wind costs (recall that we assume that there is no banking).[20] The findings comport with out expectations; the price of electricity rises as a result of the policy, but falls as wind costs fall.

Table 2 shows the difference in national generation of coal, natural gas and wind energy between the policy case and the baseline. Overall generation changes little as a result of the policy or the cost of wind generation because of the very low elasticity of demand for electricity. We see that coal generation falls in the presence of the cap, while natural gas and wind generation rise. Wind is a large share of total generation in the model, even in the baseline at 100% cost relative to other model forecasts (e.g., the EIA's Annual Energy Outlook). This is because we removed the

[20] With a very low allowance price in 2015 emissions do not quite converge to the cap under the 70% wind cost scenario.

restrictions on the amount of new wind capacity that can be installed. That all said, these results must be taken as preliminary. Through the course of our analysis we discovered a small, but consequential, coding error in Haiku which lowered the fixed operating cost of all new capacity. Not only does this reduce the overall cost of new generation, but it also puts high-fixed operating cost generators, like wind, at an advantage relative to low-fixed operating cost generators.

One interesting side-observation arises from reviewing Table 2. With a lower cost of wind generation in the presence of a cap, coal generation is rises in the later years of the analysis. That is, despite there being a cap and a lower cost competitor in the form of wind, the lower cost competitor actually displaces other higher costs forms of emitting generation, thus effectively loosening the cap and encouraging more coal generation to remain. This finding is similar to the observation that "green serves the dirtiest" when subsidies to renewable generation are imposed in the presence of a cap-and-trade system (Böhringer and Rosendahl, 2009).

Figure 4a shows the share of total auction revenue over the period from 2010 to 2030 discounted at the cost of capital (*r* in the expression that follows) required to make keep the profits (producer surplus) of incumbent firms whole over this period given the different wind cost assumptions.[21] The calculation is:

$$\% = \frac{\sum_{t=1}^{20}(1+r)^{-t}\left(PS_t^{NC} - PS_t^{C}\right)}{\sum_{t=1}^{20}(1+r)^{-t}\left(P_t^{A} * A_t\right)}$$

Where *PS* is the producer surplus either with the cap (*NC*) or without (*C*), *P* is the price of allowances and *A* is the total allocation of allowances, all scripted by time (*t*). The bar on the left is calculated assuming that the cost of wind is the same in both with and without the policy. The bar on the right assumes that the cost of wind only falls with the policy. Under these two approaches the bars are necessarily the same height under the assumption that wind costs are 100% of the native assumption in Haiku.

[21] Recall that the model is simulated at five year intervals. Producer surplus is linearly interpolated between simulation years.

As we can see, the share of allowances that would make incumbent generators operating in competitive markets whole is insensitive to the cost of wind. This finding is consistent with other studies that have looked at the sensitivity of model assumptions to the compensation required to keep regulated firms' profits whole. However, we also see that this share rises considerably if the cost of wind generation falls as a consequence of the policy. The share required make incumbent firms whole more than doubles under the lower wind cost cases. This is true despite the fact that wind generation only displaces about 6% of other sources of generation nationally as the cost of wind is 30% lower and 10-11% if it is 50% lower.

Admittedly an induced and immediate 30% or 50% reduction in the cost of new wind capacity realized at the outset of a policy is dramatic. However, the policy itself has provisions to make wind preferable to dirtier existing sources of generation other than the cap itself, such as the share of auction revenues provided to wind generation. The total value of this inducement rises overtime as the price rises relative to the decline in the cap. The total value per unit generated depends on whether the asset value of allowances rises faster than the generation of wind. We might expect that it does as the supply of wind steepens as total wind generation increases, thus limiting the amount of wind generation and in turn contributes to a higher allowance price. Figure 4b presents the preliminary findings regarding the share of auction revenue that would need to be provided to incumbent firms operating in wholesale markets to keep their profits whole. Despite the lower allowance price and increased wind generation as the share of the auction revenue going to firms rises, the share required to make incumbent producers whole *falls*. This finding clearly warrants further analysis as it contradicts the previous findings reported and our expectations based on the modeling section 3. In part it may be where new wind is locates given the subsidy. But if it holds up to further scrutiny or if the magnitude does not change significantly, perhaps importantly from a political economy perspective the effect of this particular use of the asset value of allowances is not consequential to the profits of incumbent firms.

5 Conclusion

The effect of a cap-and-trade program on profits depends crucially on the availability of low cost abatement options and generating sources with low emissions. These two conditions essentially determine the relationship between output and emissions; the greater the elasticity of output to emissions, the greater the increase in profits. A simple model of the electricity industry demonstrates this point, which is confirmed in the simulations of the Haiku model.

An important policy implication of this result is that technological change or economic incentives for renewable generating units reduces profits of existing generating units. Such changes therefore reduce the share of permits that must be auctioned to prevent these units from earning positive profits under regulation. Extensions to this analysis include exploring how the level of the cap effects compensation, the importance of the emission rate of the marginal producer of the final good, and the pricing regime in the market (i.e., whether regulated sources face marginal cost or cost-of-service pricing as is common in the electricity sector), as well as the elasticity of demand.

Future work may focus on how the allocation of allowances to clean units will affect the compensation to dirty firms, and that R&D policy will over time affect the relationship between output and emissions. Of course, the latter needs to be considered in the context of the lifetime of capital; in a partial equilibrium model it is only the incumbent firms that may realize positive profits from the cap (entry of all others is subject to a zero-profit condition). If the benefits of R&D are only realized in the long run, after a full turnover of the existing stock of capital, then it may not have an influence on the profits of incumbent firms. However, the incentive to bank allowances under a cap that declines over time may fall, and there may still be a welfare effect on incumbents.

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Tables and Figures

Table 1: Electricity Price, Allowance Price, and Emissions under Different Wind Cost and CO_2 Policy Assumptions.

		2010	2015	2020	2025	2030
National Electricity Price (2005$/MWh)	No Cap, 100% Wind	$ 81.10	$ 77.86	$ 80.27	$ 81.24	$ 82.53
	No Cap, 70% Wind	$ 79.79	$ 76.62	$ 79.03	$ 79.75	$ 81.42
	No Cap, 50% Wind	$ 78.49	$ 75.33	$ 77.38	$ 78.54	$ 80.42
	Cap, 100% Wind	$ 81.63	$ 82.95	$ 89.17	$ 93.76	$ 99.61
	Cap, 70% Wind	$ 80.04	$ 77.68	$ 85.85	$ 89.89	$ 94.33
	Cap, 50% Wind	$ 78.80	$ 76.09	$ 81.43	$ 86.53	$ 91.12
Allowance Price 2005$/ton	No Cap, 100% Wind	$ -	$ -	$ -	$ -	$ -
	No Cap, 70% Wind	$ -	$ -	$ -	$ -	$ -
	No Cap, 50% Wind	$ -	$ -	$ -	$ -	$ -
	Cap, 100% Wind	$ -	$ 7.09	$ 15.20	$ 23.54	$ 30.39
	Cap, 70% Wind	$ -	$ 0.13	$ 13.60	$ 20.66	$ 25.07
	Cap, 50% Wind	$ -	$ 0.00	$ 8.69	$ 19.05	$ 23.96
Total CO2 Emissions (Million Tons)	No Cap, 100% Wind	2562	2670	2724	2859	2966
	No Cap, 70% Wind	2187	2328	2464	2544	2644
	No Cap, 50% Wind	2016	2149	2259	2282	2323
	Cap, 100% Wind	2470	2210	1770	1570	1380
	Cap, 70% Wind	2120	2180	1770	1570	1380
	Cap, 50% Wind	2010	2080	1770	1570	1380

Table 2: Total, Coal, Natural Gas, and Wind Generation under Different Wind Cost and CO_2 Policy Assumptions.

		2010	2015	2020	2025	2030
National Generation	No Cap, 100% Wind	4150	4390	4686	5007	5337
billion kWh	No Cap, 70% Wind	4166	4424	4709	5055	5391
	No Cap, 50% Wind	4200	4469	4767	5092	5442
	Cap, 100% Wind	4136	4284	4458	4655	4873
	Cap, 70% Wind	4169	4398	4563	4752	5017
	Cap, 50% Wind	4190	4457	4669	4875	5130
Coal Generation	No Cap, 100% Wind	1984	2038	2128	2341	2499
billion kWh	No Cap, 70% Wind	1708	1814	1941	2056	2214
	No Cap, 50% Wind	1564	1668	1778	1840	1907
	Cap, 100% Wind	1885	1625	1301	1098	901
	Cap, 70% Wind	1637	1658	1325	1142	952
	Cap, 50% Wind	1568	1584	1339	1153	977
Natural Gas Generation	No Cap, 100% Wind	787	906	845	725	641
billion kWh	No Cap, 70% Wind	686	747	753	714	625
	No Cap, 50% Wind	668	724	712	662	595
	Cap, 100% Wind	825	968	832	963	1215
	Cap, 70% Wind	701	803	791	834	1048
	Cap, 50% Wind	646	783	737	797	989
Wind Generation	No Cap, 100% Wind	164	205	426	494	543
billion kWh	No Cap, 70% Wind	584	650	762	868	922
	No Cap, 50% Wind	859	951	1072	1238	1454
	Cap, 100% Wind	176	377	699	798	862
	Cap, 70% Wind	637	713	916	1085	1217
	Cap, 50% Wind	856	955	1161	1314	1448

Figure 4a: Percentage of Allowance Revenue Required to keep Incumbent Firms' Profits Whole under Different Wind Cost Assumptions.

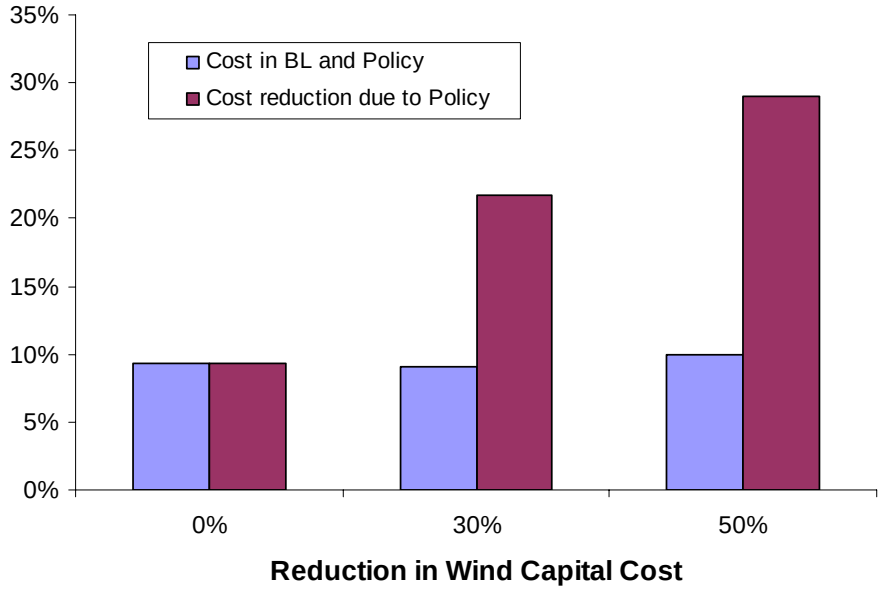


Figure 4b: Percentage of Allowance Revenue Required to keep Incumbent Firms' Profits Whole under Different Assumptions Regarding the Share of Allowance Auction Revenue Provided to Win.

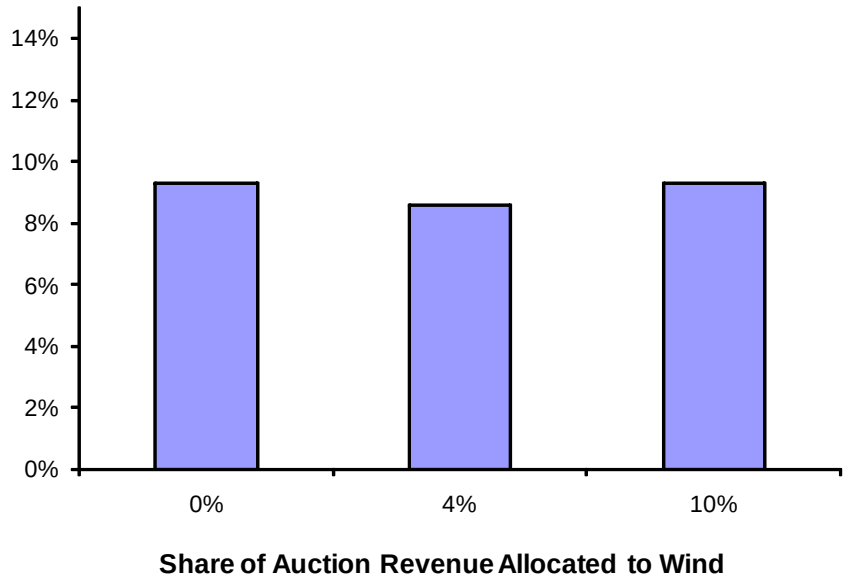


Figure 1: Electricity Market Equilibrium

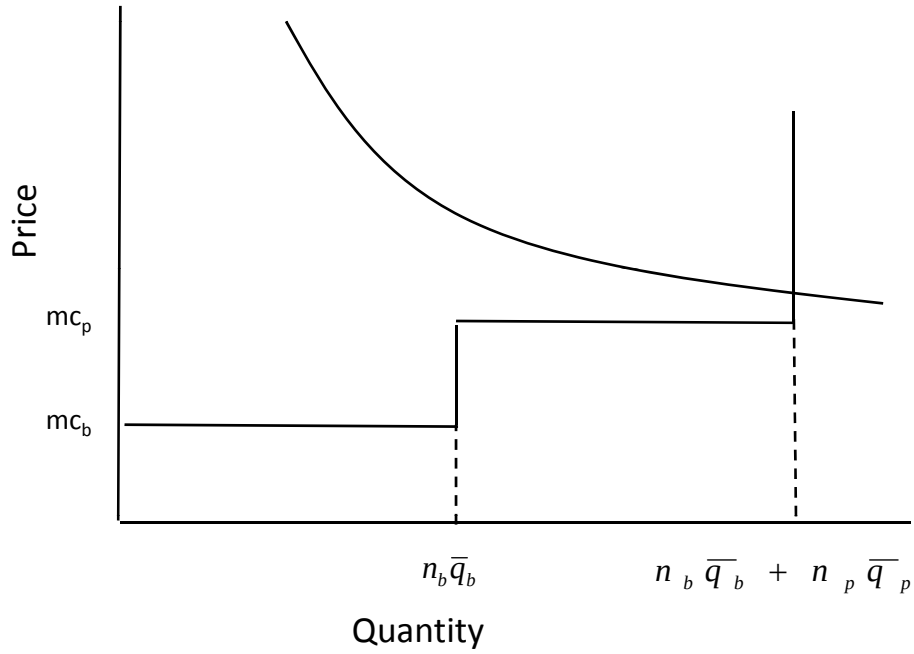


Figure 2a: Baseline Scenario, Output, Abatement Expenditure and Permit Price vs. Total Abatement

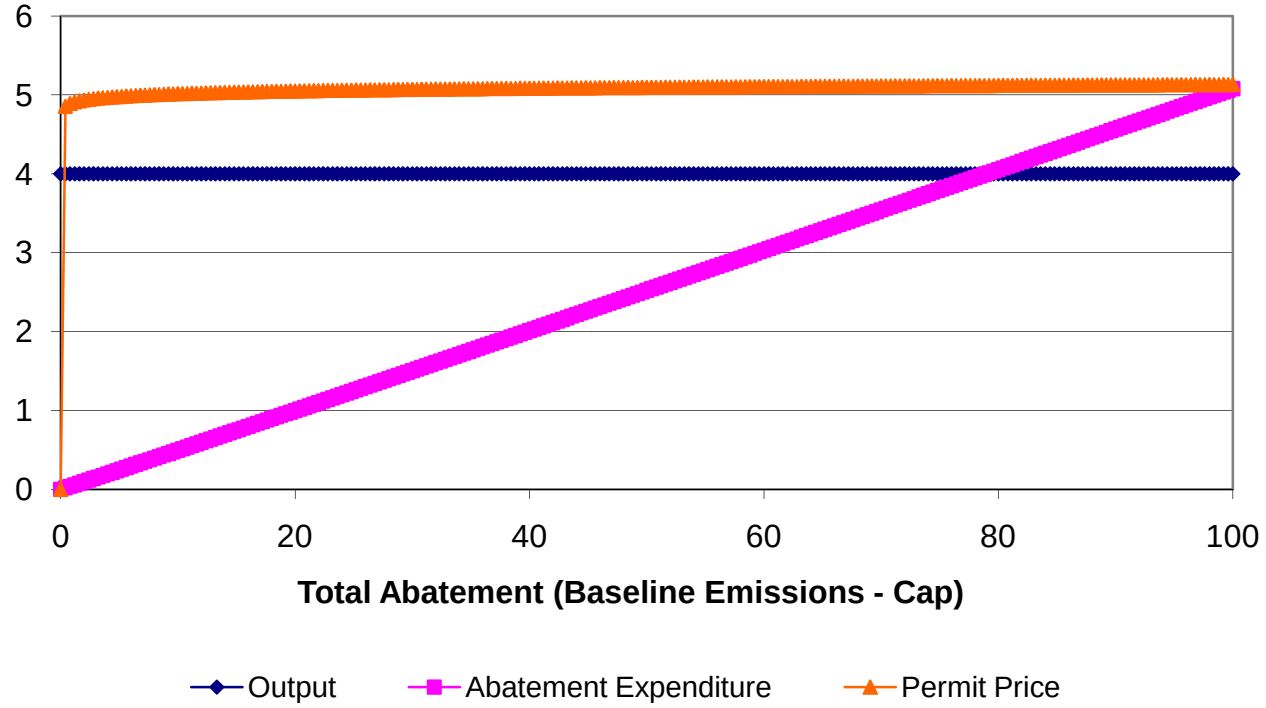


Figure 2b: Baseline Scenario, Output Price and Profits vs. Total Abatement

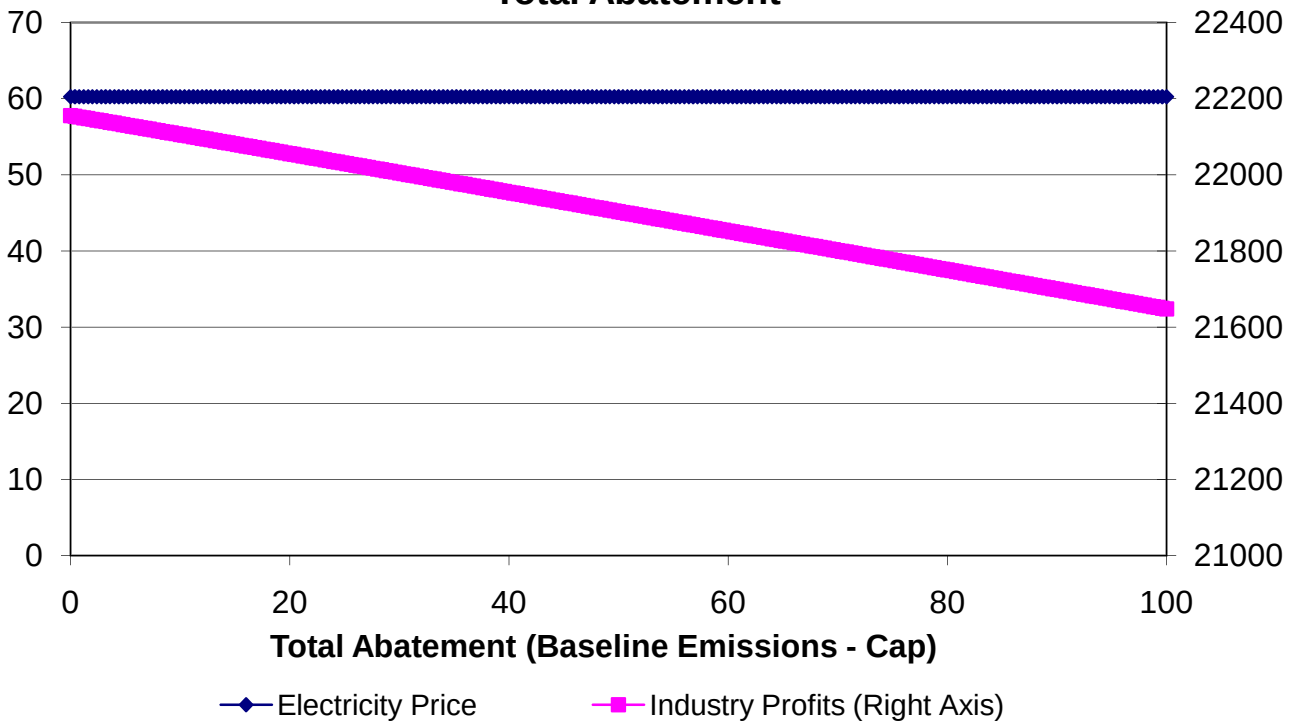


Figure 3a: Output, Abatement Expenditure and Permit Price as Functions of Beta

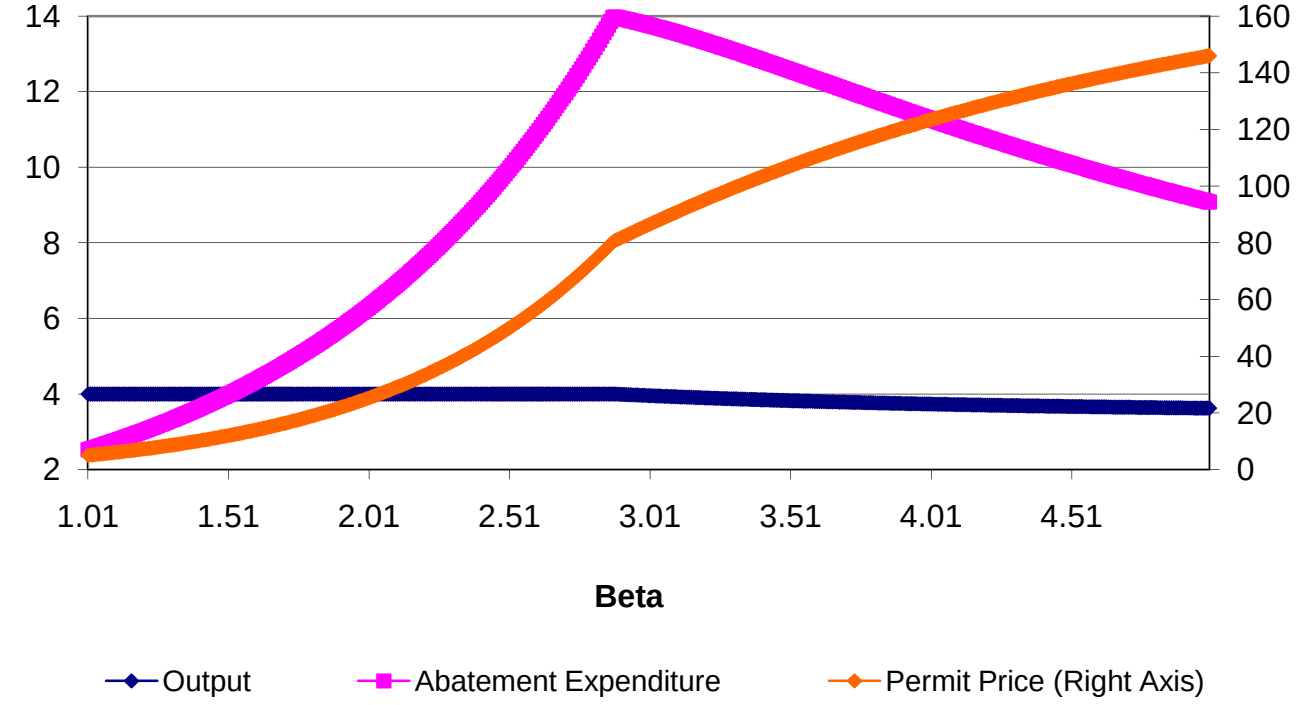


Figure 3b: Output Price and Profits as Functions of Beta

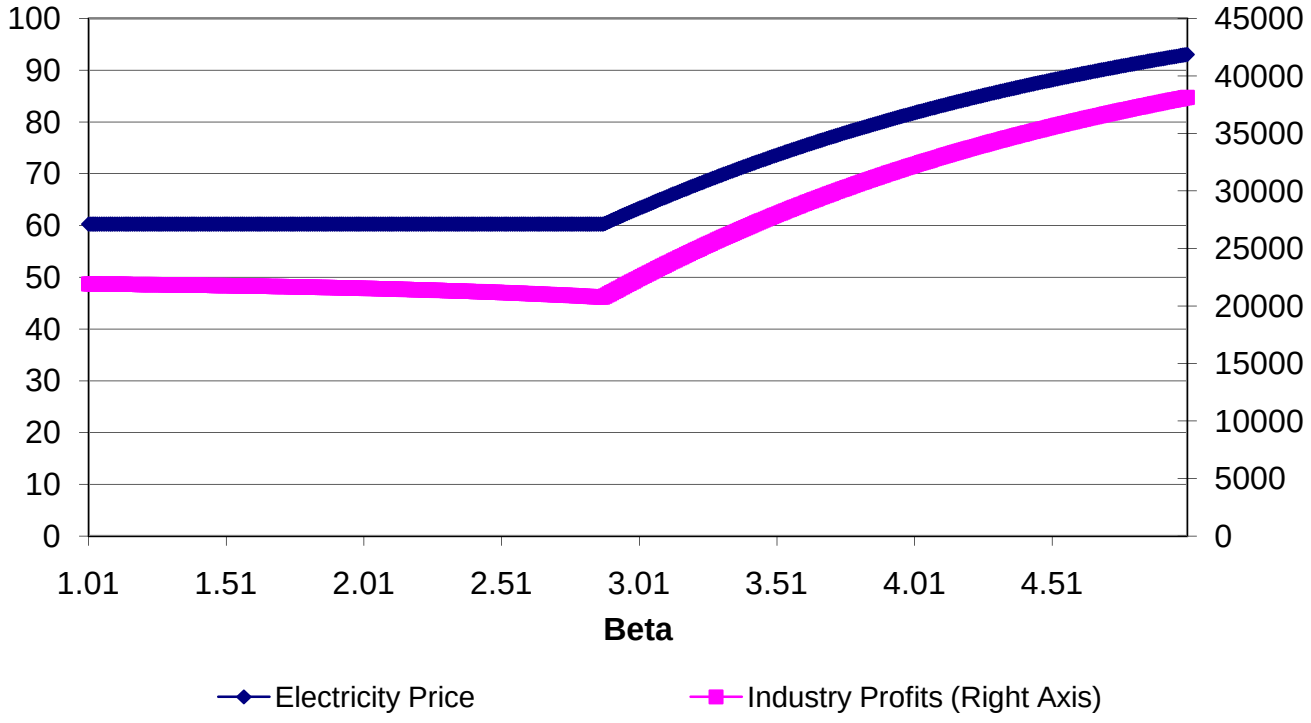


Fig 4a: Abatement and Permit Price as Functions of the Output Price Cap

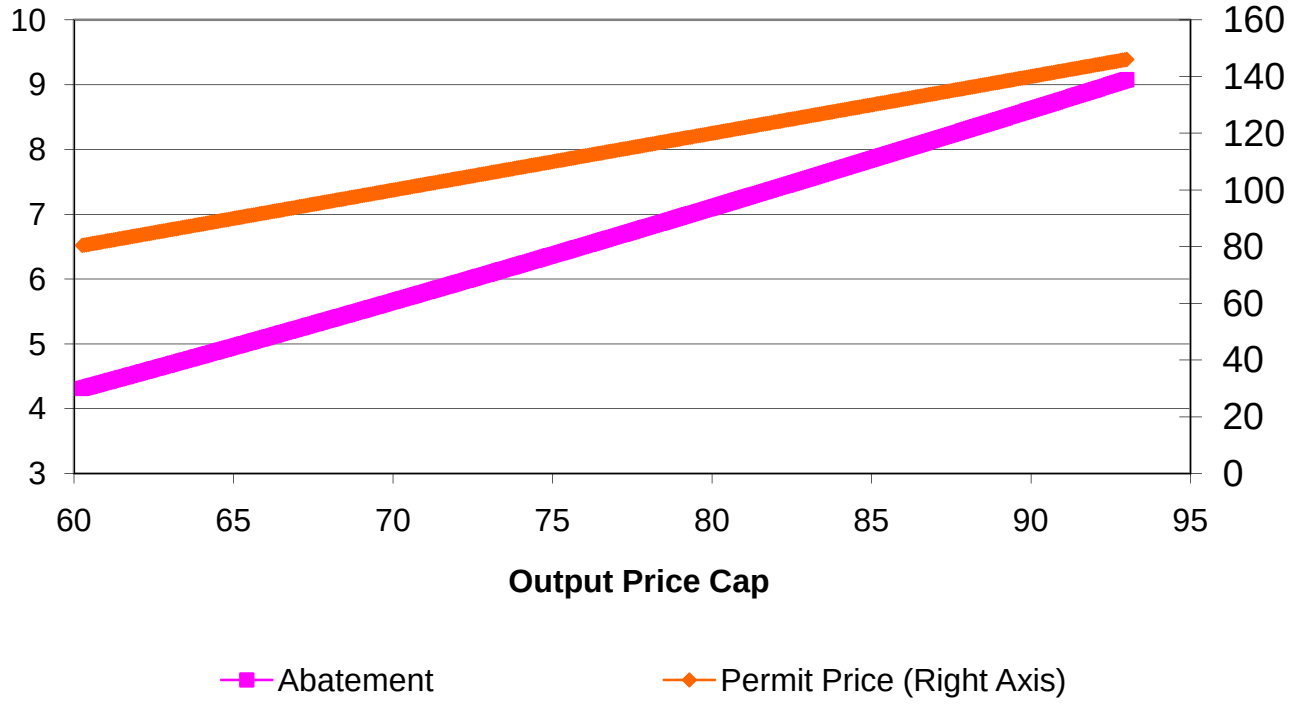


Fig 4b: Output and Profits as Functions of the Output Price Cap

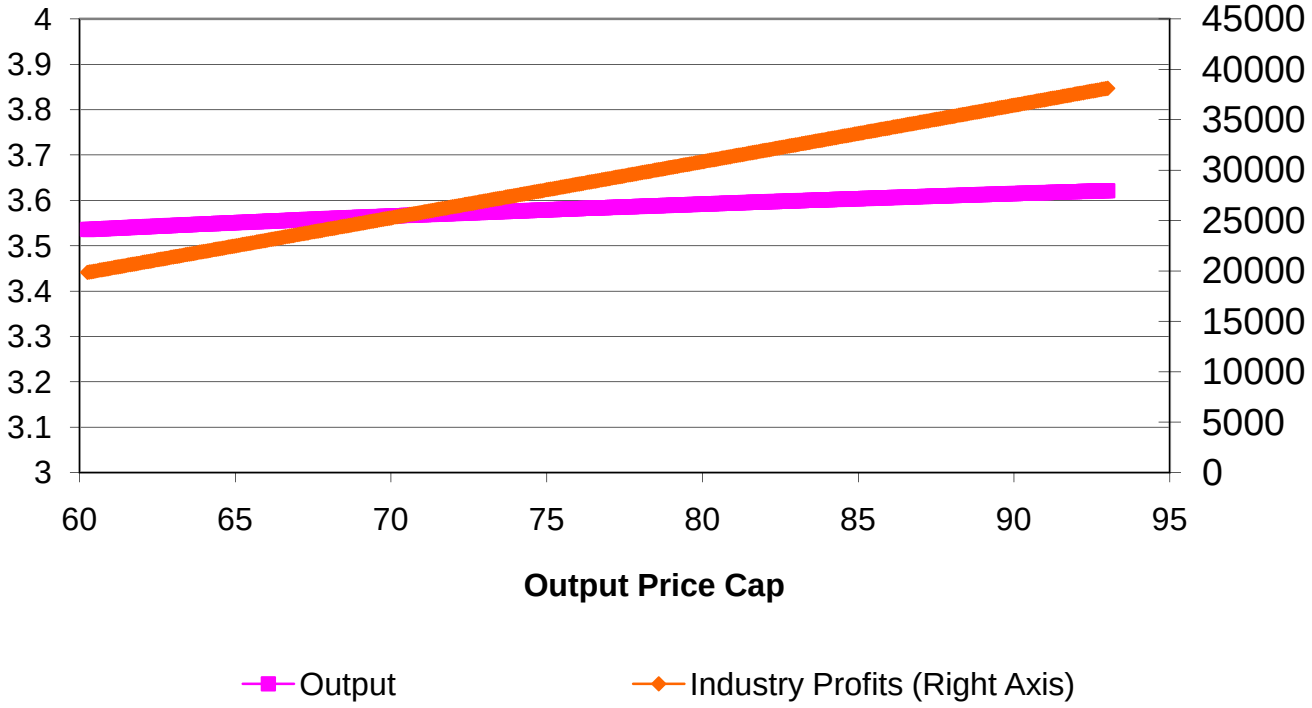


Fig 5a: Baseload Output, Permit Price and Peaking Output as Functions of Peaking Unit Emission Rate

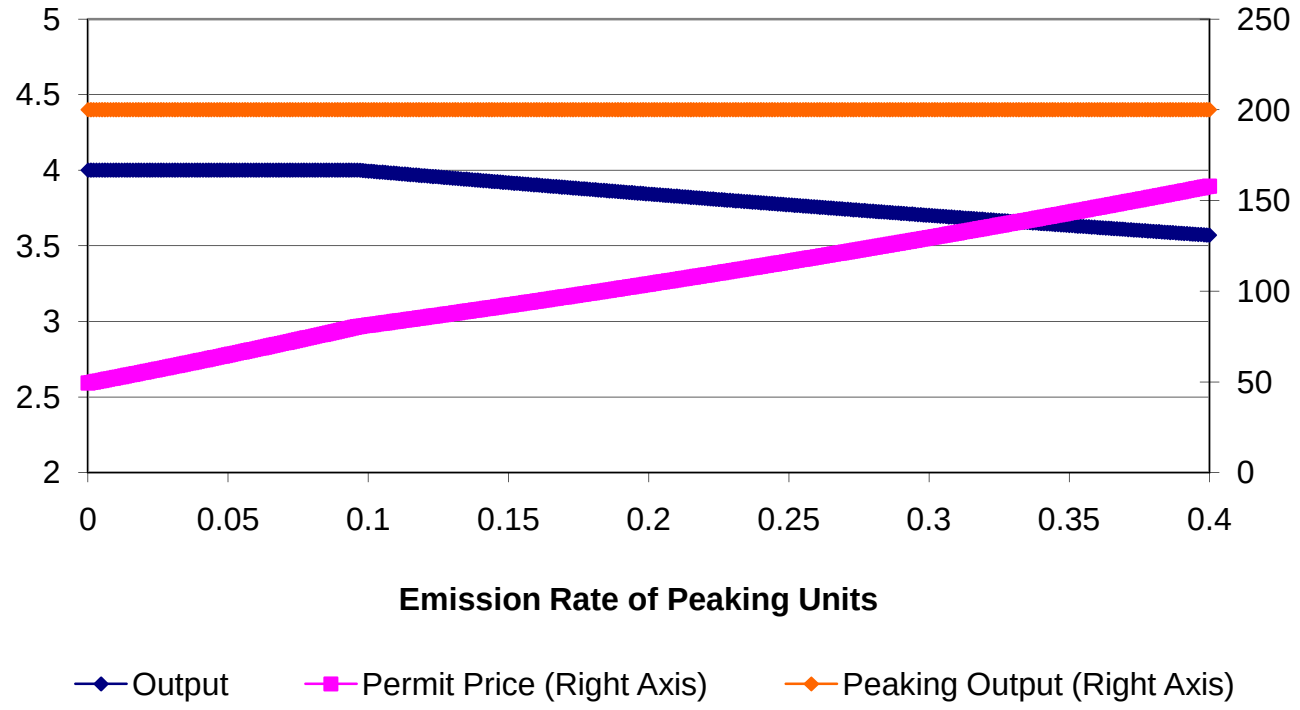
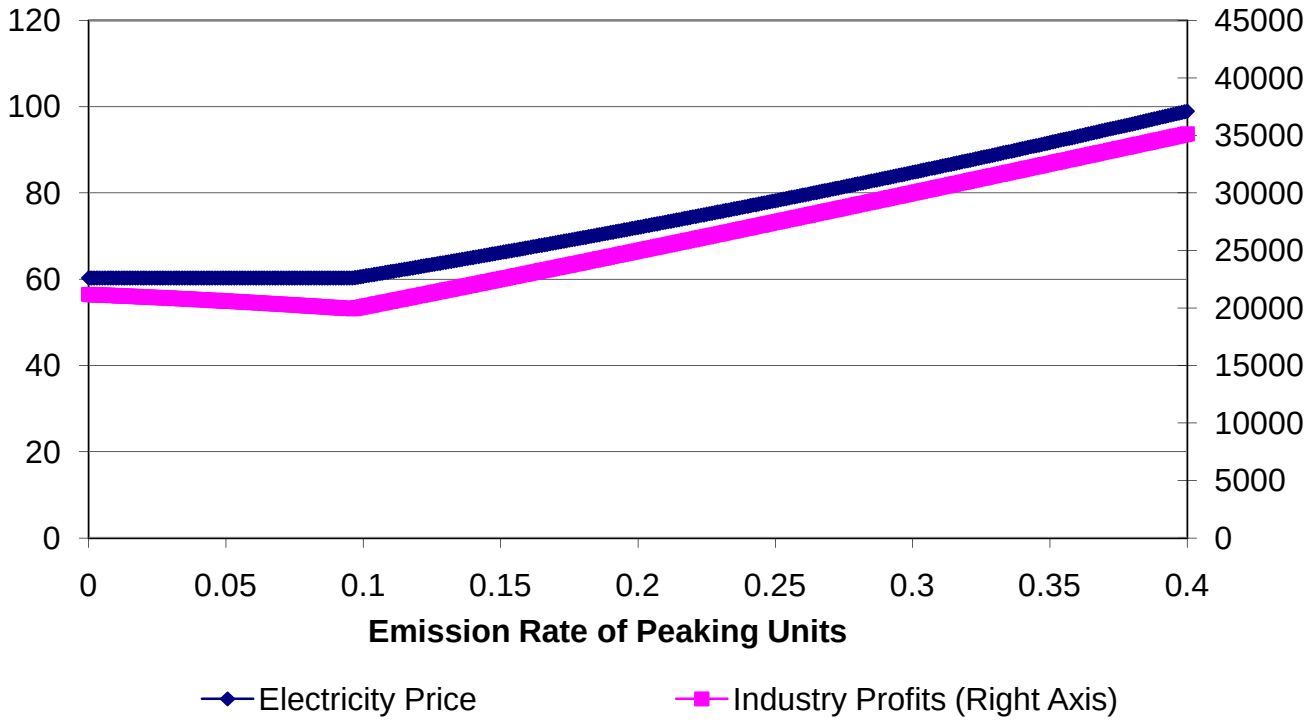


Fig 5b: Output Price and Profits as Functions of Peaking Unit Emission Rates



Session III: Winners and Losers of Cap and Trade

Discussant Comments

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The views expressed in this paper are those of the authors and do not necessarily represent those of the US Environmental Protection Agency. This paper has not been subjected to EPA's review process and therefore does not represent official policy or views.

Evaluating potential trade-offs between auctioning and giving away allowances for free

- Giving allowances away for free is often discussed as a way to compensate those that incur the cost of regulation
  - Much of the policy debate has been about how to adequately compensate firms
  - But firms pass most of the costs of regulation onto consumers in the form of higher prices.
  - Within the electricity sector, consumers are estimated to incur a loss approximately eight times greater than producers when allowances are auctioned.
- Auctioning creates revenue that can be used to:
  - Offset pre-existing tax distortions, which increases economic efficiency and reduces the overall cost of the policy
  - Compensate households for increases in the prices of energy intensive goods
- In cost-of-service regions, auctioning allowances results in increased electricity prices which improves economic efficiency since it moves these utilities closer to marginal cost pricing.

- Given the regulated nature of the electricity sector, the question examined by both studies is how many allowances would you have to give away for free to fully compensate utilities and does it effectively target the intended recipients?
  - Palmer et al also evaluate alternative compensation schemes where allowances are distributed directly to consumers via local electricity distribution companies
  - Evans et al evaluate the question of firm compensation in the face of endogenous cost reductions and its effect on firm profit

The method of allowance allocation matters in the electricity sector

- Normally, how allowances are allocated should not affect prices
  - Even if allocated for free, firms recognize the opportunity cost associated with an allowance and incorporate that value into decision-making
  - Instead the consequences are usually distributional – who captures the value of the allowances?
- Why is the electricity sector the exception?
  - Not all markets are competitive
  - Some are cost-of-service areas, which use average cost pricing.

The method of allowance allocation matters in the electricity sector

- In the electricity sector, pricing in competitive markets remains unaffected by the method of allocation, but cost-of-service regions do not: the method of allowance allocation affects production decisions.
  - Auctioned allowances or free allocation upstream of the electricity sector means that the opportunity cost of allowances will be passed along to consumers in the form of a higher price of electricity in both cost-of service and competitive regions.
  - Free allocation to electricity producers benefits consumers in cost-of-service regions (prices faced by the consumer do not rise), but benefits shareholders in competitive regions (costs are passed through to the consumer).
    - Palmer et al find that the lack of a price increase in cost-of-service regions leads to increased consumption of electricity, greater imports from neighboring competitive regions, and further increases in the price of electricity in competitive regions relative to an auction.
  - Free allocation to consumers via local electricity distribution companies largely erases the differences in burden caused by differences in regulatory structure.
    - Because allowances are allocated on the basis of electricity use, electricity prices are kept low.
    - This form of allowance allocation benefits consumers but foregoes the price signal that induces consumers to conserve electricity, making it more expensive to achieve given emission reductions (the permit price will rise).

Palmer and Evans papers

- Both papers focus on the impacts of a cap-and-trade policy.
- They examine the electricity sector and evaluate the effects of different compensation rules in a dynamic framework
- Both papers are successful in conveying that the story is more complicated than what you might initially anticipate due - in part - to the regulatory structure of the electricity sector.
- They stay agnostic with regard to who should be compensated.
- Instead, they concentrate on the distributional and sometime efficiency implications of different compensation schemes given a more careful treatment of the electricity sector.

Many policy questions arise with regard to compensation

- How much weight should we put on compensating “losers” versus other revenue uses (e.g., funding R&D, offsetting pre-existing tax distortions)?
- Should we compensate firms or consumers?
  - The literature presents evidence of diffuse but greater impacts on consumers relative to producers
  - The literature finds that some energy-intensive industries are likely to be affected, at least in the short run but sometimes also in the longer run.
  - Evans et al show that firms in the electricity sector respond to a cap-and-trade policy by reducing output, which increases profits (due to inelastic demand).
- With regard to firms, how does one determine negative impacts from the policy? At the industry level? At the firm level? Short run or longer run?
  - Palmer et al show that the level of aggregation matters in determining negative impacts.
  - Evans et al demonstrate that because abatement costs are expected to diminish in the longer run, firm profits gained through the policy will also diminish relative to initial predictions. This is because firms are then less likely to reduce output but also may imply higher levels of compensation in the long run.
- Can we minimize strategic behavior by firms to qualify for compensation?

Many policy questions arise with regard to compensation

- How do we minimize overcompensation of producers for their loss in value?
  - Palmer et al find that allocating allowances for free is a “blunt instrument” for compensation since it rewards both winners and losers of the policy. LBA may help with this but it also has the already discussed efficiency impacts on the electricity sector by foregoing demand reductions in cost-of-service regions.
  - Evans et al show that using auction revenue to subsidize new abatement technology or renewables substantially reduces profits of existing generating units.
- How do we evaluate trade-offs between efficiency and equity? How close can we get to an efficient outcome using different compensation rules?
  - A perfect example of this is illustrated with load-based allocations: the trade-off between keeping electricity prices low and foregone energy efficiency improvements, but these trade-offs exist in other forms:
  - Auctioning allowances and then compensating consumers via a reduction in the payroll tax improves economic efficiency of the policy but can be highly regressive.
  - Auctioning allowances and then compensating consumers via a cap-and-dividend policy foregoes the economic efficiency improvement but is more progressive in nature.

Comments On Two Papers on Compensation

Terry Dinan

April 29, 2009

These are my own views and should not be interpreted as those of the Congressional Budget Office

Evans, Lang and Linn: Findings

- **Find that decreases in compliance costs (renewable or abatement) *decrease* existing generators' profits under free allocation**
  - Relevant for technological innovations and subsidies
  - **Could** be used to justify giving a larger fraction of allowances to existing generators
- **Previous literature finds small fraction of allowances necessary to offset losses to existing producers when measured at industry level:**
  - Bovenberg and Goulder find less than 20% of allowances needed to hold fossil fuel suppliers and energy-intensive manufacturers harmless
  - Burtraw and Palmer find only 6% of allowances (economy wide system) necessary to hold electricity sector harmless
  - Those estimates based on given set of technologies.

Thoughts on Evans, Lang and Linn

- **Interesting that cost-lowering innovations can increase "need" for firm compensation**
  - Underscores need to think carefully about subsidizing renewable energy technologies or abatement (if not justified by other market failures)
- **How meaning full are industry-level loss estimates?**
  - Mask individual firms' gains and losses
    - Burtraw and Palmer estimate that compensating industry level losses for electricity-sector cap-and-trade would take 6% of allowance value; making losers whole would take 11%.
  - Over-compensating some firms and under-compensating others is likely to be inevitable.
    - Burtraw and Palmer's 11% estimate could climb to over 40% due to overcompensation.
- **Identifying a loss does not necessarily imply a need to compensate because not all losses can be offset. Trade-offs will be inevitable**

Paul, Burtraw and Palmer Findings

- **Previous literature:**
  - No previous analyses of load-based allocations
  - Burtraw and Palmer find free allocation to utilities benefits consumers of regulated utilities only, creates efficiency cost
- **Paul et al. highlights several points:**
  - Load based allocations suppress price increases to *all* electricity consumers.
  - Relative to direct allocation to utilities:
    - Potentially “more fair” – customers of both regulated and unregulated utilities benefit
    - Increases efficiency cost
  - Regional Distributional results vary depending on method of load based allocation
    - Population vs. emissions vs. consumption

Thoughts on Paul, Burtraw and Palmer

- **Allocations to LDCs blunt price increases:**
  - Efficiency cost
    - Creates need for higher prices elsewhere in the economy
    - Magnitude of efficiency cost depends on elasticity of demand in electricity sector
      - Sensitivity analysis could be helpful
  - Is policy more “fair”?
    - Policy subsidizes electricity industry
      - Possible to measure effect on industry profits?
    - Consumers face disproportionate burdens in other ways
      - Implications for regional and income-related effects?
- **Broader coverage decreases ability to protect low-income households**
  - Giving all households some protection for some price decreases available funds for focusing on most vulnerable households
  - LDCs lack information to target relief to low-income households.

Allocation Involves Hard Choices

- **Full Compensation is impossible: More losers than winners**
  - Based on CBO illustrative example (2000) allowance value could be roughly 85% of total policy costs
    - Based on conservative assumption that cost of tax-interaction cost same as resource cost.
  - Some of the allowance value will be used to offset government costs (roughly 25%)
- **Inability to avoid over-compensation reduces fraction of costs that can be offset**
  - E.g., generator costs total to 11% of allowance value but need significantly higher fraction (20-40 %) when overcompensation is taken into account.
  - Uses of allowance value considered by CBO and others over-compensates some households and under-compensates others

Papers Highlight Trade-Offs: No "Right" Answer as to How to Distribute Allowances

- **Producer losses**
  - Very hard to identify individual firm losses and avoid overcompensation
  - Description of producer losses as "concentrated" not accurate if shareholders have diversified portfolios
    - Shareholder losses typically borne by higher-income households
- **Worker losses**
  - Extremely concentrated on workers and communities
  - Very little analysis of the magnitude or of compensation methods
- **Consumer losses**
  - Wide-spread losses across all households
    - Some protection through COLA-adjusted incomes (Soc. Security)
  - Regressive effects
  - Compensation through local distribution companies
    - Provides widespread compensation for fraction of costs
    - Raises overall costs (if not lump sum)
    - Can't target low-income households
    - Has different regional effects depending on allocation method