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COMMENTS OF ENTERGY CORPORATION ON THE FINAL "AUCTION DESIGN FOR SELLING CO_2 EMISSION ALLOWANCES UNDER THE REGIONAL GREENHOUSE GAS INITIATIVE," REPORT, DATED OCTOBER 26, 2007

Entergy Corporation and its direct and indirect subsidiaries (collectively, "Entergy") respectfully submit these comments in response to the Final Report, entitled "Auction Design for Selling CO_2 Emissions Allowances under the Regional Greenhouse Gas Initiative," prepared by Charles Holt and William Shobe, University of Virginia, Dallas Burtraw and Karen Palmer, Resources for the Future, and Jacob Goeree, California Institute of Technology, that was provided for public comment on October 26, 2007 (the "Report"). We understand that the Report, which was funded by the New York State Energy Research Development Authority ("NYSERDA"), provides recommendations for the design of a CO_2 allowance auction system to be utilized in implementing the Regional Greenhouse Gas Initiative ("RGGI"). Entergy appreciates the effort that went into preparing the Report, and this opportunity to provide comments.

By way of brief background, Entergy is the second largest owner and operator of nuclear power plants in the United States, with five of its twelve nuclear units within the RGGI region (i.e., Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont, collectively, the "Participating States"). In addition to their critical contribution to the power supply, Entergy's nuclear facilities also provide an important and largely unrecognized environmental benefit to the RGGI Region. Since the 1970s, Entergy's and others' nuclear stations have demonstrated their value, not only by producing reliable base-load electricity, but by generating that electricity without emitting carbon dioxide ("CO_2"), sulfur dioxide ("SO_2"), nitrous oxides ("NOx") or mercury from their core generating activities. In 2006 alone, Entergy's nuclear operations avoided approximately 68 million short tons of CO_2 emissions.[1]

In addition to its nuclear-powered fleet, Entergy companies own numerous fossil-fuel facilities, contributing to Entergy's nationwide generation of over 30,000 megawatts ("MW"). Likewise, Entergy is committed to advancing renewable-power generation, and already includes in its fleet substantial wind-turbine joint ventures (in Iowa and Texas) and three hydro-electric projects (in Arkansas and Texas). As one of the largest producers of electric power in the United States, Entergy has embraced its leadership role in delivering power while improving air quality and public health and is a recognized leader in efforts to combat climate change. Entergy's commitment to redressing climate change is exemplified in actions such as a public corporate commitment to stabilize company CO_2 emissions at a level 20% below 2000 levels for the years 2006 through 2010, voluntary purchases and retirements of greenhouse gas ("GHG") reductions and vocal support for mandatory CO_2 regulations, including as an active stakeholder in and vocal supporter of the multi-year development process of RGGI.

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1 *See* Entergy's 2006 Sustainability Report, *available at* http://www.entergy.com/content/our_community/pdfs/sustainability_report_06.pdf

Furthermore, in what is widely considered a landmark break from industry, Entergy supported several states in litigation before the United States Supreme Court seeking to compel federal regulation of CO_2 by the United States Environmental Protection Agency ("EPA"). The Court's decision, in Massachusetts et al. v. EPA, requires EPA to regulate CO_2 emissions to the extent mandated by the Clean Air Act. Thus, a national program for CO_2 regulation is expected. The need to anticipate and appropriately account for this national initiative also informs Entergy's comments on the Report.

Comments

As Entergy has commented elsewhere, it supports allocation of CO_2 allowances through an open auction process with clear guidelines for the use of auction revenues. *See e.g.,* Entergy's comments on the Commonwealth of Massachusetts Department of Environmental Protection's draft 310 CMR 7.70: CO_2 and the Massachusetts Division of Energy Resources' draft 225 CMR 13.00: CO_2 (collectively, "Comments," which are attached). Because the Report addresses auction design, as opposed to policy issues (such as whether Participating States should use auctions), these comments focus on auction design.

In general terms and consistent with its prior Comments, Entergy urges the Participating States to institutionalize the involvement of appropriate energy regulators in the design and operation of the auctions, including by making such entities responsible for the administration of the auction process, the distribution of auction revenues and, if appropriate, any safety valve features designed to redress the impacts on affordability attributable to added CO_2 allowance costs. In light of the truism that air-quality regulations are inextricably linked to electric-system function and market pricing, it is important that the regulators with the requisite expertise – that is, those whose mission is to ensure that electricity consumers within the RGGI region are provided with reliable and cost-effective electricity – play a substantial role in the implementation of RGGI. Entergy commends those Participating States, such as Massachusetts, New York and Vermont, that have already taken steps to ensure the ongoing participation of state energy regulators in the implementation of RGGI. As discussed further herein via specific examples, Entergy believes that the appropriate Independent System Operators ("ISO's"), that is those that are daily responsible for electric system reliability and electricity prices, should also be involved in the design and ongoing monitoring of allowance auctions. In addition, Entergy believes that an advocate of disadvantaged or low-income consumers should be involved, particularly insomuch as additional costs may implicate affordability concerns.

In addition, these comments focus on the Report's recommendations regarding: (i) holding auctions open to anyone able to meet financial pre-qualifications; (ii) using a reserve price in each auction; (iii) banking or retiring unsold allowances that do not meet the reserve price; (iv) timing of availability of future allowances; (v) advocating for a joint and uniform auction among Participating States; and (vi) disclosing information from the auctions. All fundamental auction details, including those discussed below, should be addressed in the final regulations or in the documents governing any multi-state or regional auction. This will help ensure that the affordability, reliability and diversity of the RGGI region's electric system is not compromised by the implementation of RGGI. Each is discussed below.

A. Open Auctions

Auctions of CO_2 emission allowances that are open to the general public represent a thoughtful, market-based approach that, if allowed to operate without artificial constraints that negatively impact the demand, supply or price of the commodity, may send proper price signals with respect to the emission of CO_2. Entergy therefore supports the Report's recommendation that any person or entity be eligible to participate equally in all auctions of CO_2 emission allowances. Thus, any auction of CO_2 allowances should be open to all participants, including environmental organizations, brokers and all electric generators, regardless of their fuel source or regulated status under the RGGI, and without any rights of first refusal. Including entities beyond those units directly governed by RGGI as parties qualified to purchase CO_2 allowances (in the same manner as those entities subject to RGGI), and to subsequently hold or otherwise transfer them, is essential to fostering a sustainable trading market that will achieve the RGGI goals. The Report concludes as much in direct terms, by stating unequivocally that:

> It is clear from both experiments and theory that limiting auction participation falls in the category of rules that are both ineffective and likely to do more harm than good. By lowering participation rates and restricting participation to firms with a greater ability to tacitly collude, this strategy runs the risk of substantially increasing the risk of collusion in the auction.

See Report, pg. 74.

Moreover, the Report allays any concerns that open auctions could encourage hoarding behavior that would not otherwise occur. For example, the Report notes that:

> For the most part, these [five potential types of hoarding behavior] are not issues of auction design. Rather, these issues arise as a consequence of the structure of the RGGI market. Auctions might contribute to hoarding if somehow auctions made it substantially easier for hoarders to obtain RGGI allowances than would otherwise be possible. However, if there is a liquid allowance market, as most anticipate, then auctions do not provide an opportunity that would not already exist in the allowance market.
>
> [and]
>
> Once the use of the auction for surprising the market with a large, sudden spike in demand is restricted, there is little remaining difference between the auction and the spot market with respect to facilitating hoarding.

See Report, pg. 68-69.

As added measures against hoarding and speculation, Entergy suggests that allowances have finite effective dates and also that there be a limit on banking of allowances (with an exception solely for the first compliance period applicable to the operation of new facilities, including retrofits to lower emitting fuel sources, as a method of encouraging emissions reductions and future development of electric supply within the RGGI region as opposed to in areas that could present leakage problems). Such an approach may lower demand for allowances in the early auctions, when it is anticipated that low allowance prices, based in part on loose caps, may otherwise encourage allowance hoarding or speculation.

As a related matter, any requirement that individuals or entities meet pre-qualification standards, including minimum financial requirements, to participate in the auction of allowances should be established, and explained in sufficient detail, to ensure that participation in the auctions is not inappropriately limited.

B. Reserve Price

Entergy supports the use of reserve prices for CO_2 allowances. A reserve price is particularly important in the early stages of RGGI auctions in light of concerns that the starting allowance budgets (i.e., "caps") are inadequate to establish viable markets. A properly set reserve price will help ensure that the market does not reflect distorted values of CO_2 allowances due to early over-allocation of allowances, or result in problems such as those recently experienced in the European Union (upon the discovery that too many allowances were allocated to regulated entities). Thus, whether the auction process is considered a means of price discovery or revenue generation, the inclusion of a reserve price is essential for fulfilling such objectives.[2]

The use of a reserve price, which should not be publicized, need not significantly adversely affect the efficiency of the auctions. As discussed in the Report, an efficient allocation of allowances "means that CO_2 reductions are being made at the lowest cost to society." *See e.g.,* Report, pg. 21. In the context of RGGI, such "costs to society" consist of more than the price of allowances paid by regulated generators. As memorialized in the RGGI Memorandum of Understanding ("MOU") executed by the Participating States, the objectives of RGGI include the "development, and deployment of carbon emission control technologies, renewable energy supplies, and energy efficient technologies [and] demand-side management practices." *See* RGGI Memorandum of Understanding, 6th Whereas Clause. To more fully recognize the objectives of RGGI, the reserve price should be set at a level that would maintain a minimum rate of progress towards reducing emissions, as discussed at page 57 of the Report, as opposed to simply tracking market prices.[3]

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2 Entergy also concurs with the Report's recommendation to use a reserve price, including as a hedge against the risk of collusion. *See* Report, pg. 56. Entergy acknowledges that a reserve price may increase allowance prices, particularly early in the auction process (when market dynamics are less well settled), potentially conferring a benefit on non-emitting generation sources that participate heavily in market trading (i.e., outside of the long-term power purchase agreement framework that is the norm for much of the base load non-emitting sector).

3 According to a report prepared by the Brattle Group, carbon prices must reach approximately \$30 per ton to cause substantial reductions of CO_2 produced by the power sector. *See* "The Economics of U.S. Climate Policy, Impact on the Electric Industry" (March 2007), attached as Exhibit A. The Brattle Group has also predicted that even the most marginal existing coal plants will not be induced to retire, or retrofit for CO_2 capture, until prices reach at least \$40-\$60/ton. *See* Dean M. Murphy, The Brattle Group, "U.S. Climate Policy, Effects on Business and the Environment," The Conference Board (Sept. 26-28, 2007), attached as Exhibit B. Information such as this should be taken into account in setting reserve prices in order to assure that the auction is designed with the objective of meeting RGGI's core goal of reducing CO_2 emissions.

C. Use of Allowances that Do Not Meet the Reserve Price

The majority of allowances that do not meet the reserve price in a particular auction should be retired. This further advances the important goal of reducing CO_2 emissions and promotes the additional objectives of encouraging lower and non-emitting sources of energy, energy efficiency and demand-side management. Moreover, Entergy concurs with the finding in the Report that, particularly given over-allocation in the initial caps, rolling forward unsold allowances for sale in future rounds risks creating an impression that the auctions are failing. *See* Report at pg. 58.

Entergy suggests that a small portion, e.g., 10%, of allowances that do not meet the reserve price should be placed in what the Report refers to as a "contingency bank" for a period of two years, while the rest are retired. Allowances placed in the contingency bank should be available only to protect against extreme price volatility in the cost of allowances, as measured both at auctions and in the secondary market. The trigger price for a release of the allowances in the contingency bank must be higher than the offsets trigger and safety valve trigger established in the RGGI MOU in order for those triggers to retain any impact, particularly in light of the Report's recommendation to hold quarterly auctions. Neither the offsets trigger nor safety valve trigger are considered to have occurred unless the specified allowance price has been exceeded for a period of twelve months, on a rolling average. Therefore, assuming that the Participating States wish to retain the structure of offsets triggers and safety valve triggers established in the MOU and Model Rule, the threshold allowance price for releasing allowances in the contingency bank must, at a minimum, exceed the higher value of these triggers, i.e., the safety valve trigger.

Because the purpose of a contingency bank is to protect the market from excessive price spikes or volatility, it is likely impossible to set at the outset what type of price increase would be sufficient to merit a release of allowances form the contingency bank. For example, a 100% increase in allowance prices may not be problematic if the starting price of an allowance were $0.75 cents, but may be negatively disruptive to the electric system if the initial price were $1,000. As such, releases of allowances from the contingency bank will need to be based on real-time decisions. Electricity regulators and ISO's operating in the RGGI region are well situated to make such decisions, given their expertise in electric system reliability, affordability and fuel diversity. Entergy recommends, therefore, that these regulators and ISO's be collectively responsible for determining when allowances from the contingency bank are made available in auctions. Thus, the implementation of any change to the auction system will be appropriately contingent on determinations regarding the strength (e.g., reliability, affordability and diversity) of the electrical system, rather than solely the cost of allowances. The energy regulators and ISO's should also have the discretion of determining whether such banked allowances should be available to the all bidders or the subject of a right of first refusal from generators regulated by RGGI. To the extent necessary, any additional costs borne by the ISO's due to this responsibility can be offset by auction revenues.

Entergy acknowledges that allowances that are retired, as opposed to sold at a later date via the contingency fund, may represent lost financial value to the Participating States. However, because any such lost revenue will come in exchange for reduced CO_2 emissions, which is the goal of RGGI, Entergy does not expect that any Participating State would object to the retirement of allowances that do not meet the reserve price on these grounds. However, it is fair that such costs be equally divided among the Participating States that elect to participate in a regional auction. Thus, for instance, the total number of allowances for a vintage that are retired due to not meeting the reserve price should be subtracted on a pro rata basis from the budget of each Participating State that is a member of the regional auction, regardless of when it joined the auction. Given speculation that the early allowance budgets are higher than needed, such a mechanism may help deter late entry into the auction by Participating States that anticipate low sales prices in the early auction periods, and avoid creating financial rewards to states that are late in implementing RGGI.

D. Timing of Availability of Future Allowances

Auctions of future allowances should not be held so far in advance of their vintage years so as to create opportunities for bidders to "low ball" bids for future allowances based on the knowledge that there will be sufficient additional opportunities/time to acquire the later vintage allowances, particularly in light of the long compliance periods under RGGI. If bidders are successful in acquiring future allowances at early low bids there will be a downward pressure on the ongoing prices of future bids for such allowances, given that the pool of bidders will have been reduced, that could impact the market for multiple years with false distortions of the price of CO_2 emissions. Rather than making future allowances available four years in advance of their vintage year, Entergy recommends that such allowances be introduced to the auction no earlier than a year before their vintage. In addition, Entergy recommends that fewer of the allowances from a vintage year be available before the start of the relevant year than the 50% suggested in the Report. Thus, for instance, an allowance for vintage year four would first be available at the beginning of the third year of RGGI and up to 20% of the allowances for vintage year four could be offered for sale prior to the start of the fourth year of RGGI. This time frame recognizes and is consistent with the possibility that the first RGGI compliance period could expand to four years, if the relevant price triggers outlined in the RGGI MOU are met. This approach has the added benefit of reducing the administrative burden and costs placed on the regulators during the start-up years of the auction process by removing the need for multiple auctions at the outset.

E. Joint and Uniform Auction

To the extent appropriate safeguards and participation is ensured, Entergy supports the Report's finding that a "joint regional auction is far preferable to separate state auctions for several reasons", including sending accurate price signals, avoiding gamesmanship between Participating States and reducing administrative costs to both the Participating States and bidders. *See* Report, pg. 40. A uniform auction is also appropriate in light of the fungible nature of CO_2 emission allowances, i.e., an allowance from one Participating State's RGGI budget of CO_2 emission allowances provides the same rights to its holder as an allowance from the RGGI budget of any other Participating State. Thus, allowances sold at an individual state's auction should be eligible to be bought and used by individuals, entities and facilities in any Participating State. As such, a uniform auction process, and the benefits that it provides, is a sensible approach.

F. Public Disclosure of Auction Information

The disclosure requirements applicable to entities purchasing CO_2 emission allowances in an auction must balance the objective of creating a transparent auction process with the confidentiality needs of the business sector. The Report recommends that the following auction information be publicly revealed: (i) clearing price; (ii) identities of winning bidders; and (iii) quantity of allowances obtained by each winning bidder. The purpose of these latter two pieces of information can be achieved by instead publicly reporting the amount of allowances bought by various "types" of auction participants, e.g., generators regulated pursuant to RGGI, brokers, environmental organizations, etc. This latter approach provides the type of information necessary for the public to assess market behavior while protecting the confidentiality of individual businesses in a manner that avoids discouraging participation by any group of participants.

Entergy supports the Report's recommendation that individual bid values, whether winning or losing, not be disclosed. In a similar vein, if an auction process utilizes non-uniform purchase prices, the price paid for allowances by any particular participant should not be made public in connection with that participant's identity.

Conclusion

Entergy shares and supports RGGI's goal of addressing CO_2 emissions in a manner that supports a reliable and affordable energy supply for the RGGI region's citizens. Entergy therefore appreciates the opportunity to submit these comments and welcomes the opportunity to work further with the Participating States to help create an auction process that will help achieve a meaningful, innovative and successful regulatory program and allowance trading program to support RGGI's progressive CO_2 emission standards. Any questions regarding our comments may be directed to Elise N. Zoli at 617-570-1612.

Exhibit A

TECHNICAL REPORT

March 2007

The Brattle Group

THE ECONOMICS OF U.S. CLIMATE POLICY
Impact on the Electric Industry

This paper is based on collaboration between *The Brattle Group* and FPL Group. A separate paper released by FPL Group presents an executive-level summary and policy recommendations; this paper provides greater detail and supporting analyses.

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I. INTRODUCTION

Greenhouse gases and their potential to cause global climate change are a topic of substantial public concern and discussion recently, but discussions have not generated agreement about policy goals, nor the mechanisms for reaching them. This paper addresses several questions about a potential U.S. carbon dioxide (CO_2) control policy. First, if some such policy is to be enacted, how could it be structured, in broad terms, to achieve meaningful CO_2 reductions efficiently and without undue risk to the economy?[1] Policy analysts consistently find that a market-based mechanism that prices CO_2 emissions throughout the economy provides incentives for cost-effective emission reductions. Market-based mechanisms include cap-and-trade allowance systems and taxes or fees on CO_2 emissions. Second, how would such a policy affect the economy and energy markets, particularly the electric industry? We examine herein how a policy might be structured to be effective, efficient, avoid excessive burdens, and be relatively equitable across industries, consumers, and regions.

This paper focuses primarily on the electric sector, utilizing insights from simple but realistic analyses, and also looks briefly at effects on other major industries and on consumers. Based on our analysis and reviews of work by others, we draw several high level conclusions regarding policy design, and outline and analyze a proposed CO_2 policy structure. In particular, we conclude that a sensible greenhouse gas policy should be able to achieve substantial CO_2 reductions without unduly threatening the electric industry or the overall economy. To best achieve this, the policy should be structured to give a high degree of certainty about its long run economic impacts, and should include mechanisms to reallocate burdens and risks fairly across consumers and some producers.

Most discussions of mandatory, market-based policies have focused on allowance cap-and-trade policies, largely because of the recent success of cap-and-trade for other pollutants such as SO_2 and NO_x. However, our analysis suggests that a policy that imposes a tax or fee on CO_2, coupled with mechanisms to return the revenues to the economy, is likely to have several key economic advantages over a cap-and-trade approach.

II. ELECTRIC SECTOR CO_2 ABATEMENT, AND IMPLICATIONS FOR CO_2 POLICY

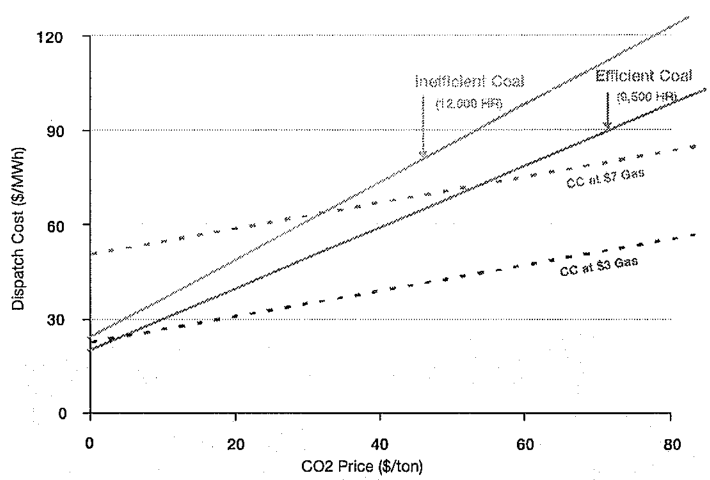
Prior to the recent increases in natural gas prices, analyses of economy-wide policies to reduce CO_2 emissions typically found that the most cost-effective reductions were available in the electric sector from dispatching existing and new gas-fired plants more, and coal plants less. Natural gas has about one-half of the carbon content of coal and newer gas-fired combined-cycle power plants are more efficient in converting heat into electricity. Although natural gas has always been more expensive than coal on an energy basis, when gas was at \$3/MMBtu, a modest CO_2 price could and would induce disproportionately large emissions cuts in the electric sector – maybe most of the cuts needed to meet a desired emission target.[2]

Unfortunately, sharply increased natural gas prices over the past few years have dramatically increased the difference in fuel costs between gas-fired and coal-fired generation. This larger price spread means that a much higher CO_2 price would be required to cause significant fuel switching. As Figure 1 illustrates, when gas prices were around \$3/MMBtu, a modest CO_2 price (\$0-5/ton) was enough to make an efficient gas-fired combined cycle plant more economical to operate than many coal plants.[3] But with gas prices around \$7/MMBtu as they are now, a CO_2 price of \$35-55/ton would be needed to induce substantial fuel switching.[4]

High natural gas prices also affect the choice of generating technology for new capacity. Natural gas combined cycle plants were the overwhelming technology of choice for capacity expansion through the late 1990s, but for the upcoming decade utilities have announced plans to build over 100 gigawatts of new coal-fired generating capacity. In order to influence the technologies selected for new baseload capacity toward lower carbon-emitting alternatives such as natural gas combined-cycle (NGCC), integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS), nuclear and renewables, CO_2 prices would have to be anywhere from \$5 - \$40/ton. These future CO_2 prices also would have to be credible and predictable in order for generation owners to confidently choose low-carbon alternatives in the near term, anticipating the CO_2 price impact on long-run operating economics.

Recent increases in natural gas prices, therefore, have substantially altered the outlook for cost-effective CO_2 emission reduction in the electric generation sector. This observation has significant implications for overall CO_2 policy design as well, which have not yet been reflected fully in policy discussions. First, this reminds us that forecasts of policy effects depend significantly on highly uncertain future conditions such as relative fuel prices and technology costs, and that policy should be designed to accommodate such uncertainties. Second, it suggests that an inflexible near-term policy could prove costly – if the U.S. were now operating under a strict CO_2 emission cap, the economic costs of achieving that target would be substantially higher than estimates made just a few years ago. Third, it shows the risk of relying too heavily on one sector – such as electric generation – to provide the bulk of emission reductions. Finally, it implies that, in the electric sector and probably most others, CO_2 reductions will arise primarily from efficiency, conservation and long-run technology substitution. A CO_2 policy should be designed to encourage these kinds of reductions in particular.

Figure 1: *Gas vs. coal dispatch economics, with CO_2 price effect*



III. DESIGN CONSIDERATIONS FOR AN EFFICIENT CO_2 POLICY

A great deal of economic analysis has been applied to identifying cost-effective policies to reduce CO_2 emissions, and a fair amount of consensus has been achieved on some of the broad policy principles. In general, these analyses have concluded that the most efficient and effective policies would be mandatory, market-based, and economy-wide. Less attention has been paid to some other policy features that are nonetheless important for long-term policy success. In particular, a CO_2 policy should have economic effects (i.e., CO_2 prices) that start modestly and phase in predictably to more ambitious levels over a long time frame. To the extent that a market-based policy would generate substantial revenues, the policy should include mechanisms to return these to the economy to mitigate negative effects and reallocate overall economic burden.

3.A. MANDATORY CONTROLS WILL BE NEEDED TO ACHIEVE SIGNIFICANT EMISSION REDUCTIONS

A mandatory program is almost certainly necessary to substantially reduce CO_2 emissions over time. Some argue that voluntary technological solutions will address the problem, pointing out that the carbon intensity of the U.S. economy (CO_2 emissions per unit of GDP) has declined over time, a trend that is expected to continue. However, absolute emissions have nonetheless steadily increased, since economic growth has been faster than the decline in carbon intensity. It is unlikely that purely voluntary measures will be effective. Unless CO_2 policy is mandatory there will be little incentive for producers or consumers to adopt low-carbon technologies or otherwise pursue emission reductions, beyond what would be economic in the absence of a CO_2 policy. Indeed, the fact that competitors could "free ride" would create a disincentive to adopt CO_2 abatement measures.

3.B. MARKET-BASED POLICY WILL FOSTER EFFICIENT EMISSION REDUCTIONS

Virtually all analyses of CO_2 emissions conclude that market-based mechanisms offer the most efficient means to reduce emissions. In this context, market-based means that the policy would price CO_2 emissions in the economy, but still allow consumers and firms to decide whether to respond to these costs and what action to take. In other words, market-based policies let normal, decentralized economic behavior (cost minimization, profit maximization, consumer choice, and innovation) drive the response to the price of CO_2 instead of using a "command-and-control" approach to require specific actions. Economic efficiency is particularly important in this instance because the program would have widespread effects, so even small inefficiencies would be costly in the aggregate. A cap-and-trade program is one way to do this, and has met with notable success in reducing sulfur dioxide (SO_2) and other emissions in the electric generation sector. The other basic market-based mechanism is a tax or fee on CO_2 emissions. Both of these mechanisms create incentives for efficiency by equating the marginal cost of CO_2 reductions from different sources in the economy. While some supplemental policies might usefully complement a market-based approach – such as efficiency standards (e.g., CAFE standards for vehicles, appliance standards) or subsidies (R&D and investment incentives for low-carbon technologies or CO_2 abatement) targeted at particular sectors or activities – the core of an effective CO_2 policy should be market-based to enhance overall efficiency.

3.C. AN ECONOMY-WIDE APPROACH REDUCES CO_2 ABATEMENT COST AND SPREADS THE COMPLIANCE BURDEN

Given that there is no easy solution to the CO_2 problem (i.e., no sector or sectors can easily yield reductions sufficient to meet desired overall reductions), an economy-wide policy is likely to yield the most cost-effective emission reductions and also spread the burden equitably across sectors.[5] To the extent that all CO_2 emissions are covered (i.e., the policy would put a price on CO_2 emissions from all fossil fuels used in the economy) then every industry and consumer will face a consistent CO_2 price across all uses. Thus, firms and consumers will be able to adjust production and consumption patterns to most cost-effectively reduce aggregate CO_2 emissions. In contrast, targeting one or few industries would be less efficient, potentially more disruptive, and may be viewed as unfair. A sectoral approach would likely impose too great a burden on the targeted sector(s), would neglect efficient emission reductions from non-targeted sectors and might in some cases just drive targeted industries and CO_2 emissions overseas, with little or no global CO_2 reduction.

Pricing CO_2 "upstream" would facilitate a market-based, economy-wide policy. CO_2 is emitted from millions of sources, including homes, cars, trucks, commercial buildings, and power plants, making it entirely infeasible to measure and price actual CO_2 emissions throughout the economy. However, since the carbon content of different types of fossil fuels is easily measured and is proportional to ultimate CO_2 emissions through combustion, a simple and practical alternative is to assess a fee on all fossil fuels "upstream" at or near the point of extraction or importation, based on their carbon content. Only about 2,000 sources would need to be controlled, a very modest administrative burden, and this would ensure that virtually all fossil fuels, for all uses, are covered under the policy.[6] In order to more accurately target CO_2 emissions from fossil fuel combustion, non-combustion uses of fossil fuel (for example, petrochemical feedstocks) should generally be exempted from the CO_2 fee, e.g., through a credit mechanism. Similarly, a rebate or credits should be available for verifiable carbon capture and sequestration projects in order to ensure appropriate and efficient incentives for such solutions.

3.D. A GRADUAL, PHASED-IN POLICY WILL AVOID DISRUPTIONS

Because meaningful policies to reduce CO_2 emissions can affect nearly every aspect of economic activity, and the climate change problem poses a long-term environmental challenge, the economic costs of imposing ambitious near-term targets could exceed the environmental benefits obtained (and regardless of cost-benefit, may simply be politically unacceptable). This does not mean that policies can be delayed indefinitely, but rather that a gradual approach – even one with ambitious long-term goals – can help minimize disruptions while still making real progress toward emission goals. Gradualism is important because so much of the current level of CO_2 emissions come from long-lived investments already in place in energy production, conversion and end-use. A cost-effective policy should influence technology choices in the timeframes normally associated with making such investments. While such policies certainly can accelerate the deployment of lower-carbon investments, if this process is too rapid or too abrupt, then the values of existing assets can be substantially impaired, increasing the costs of adjustment, and potentially imposing unacceptable burdens on the overall economy.

Although a relatively high CO_2 price may ultimately be needed to achieve significant emission reductions, beginning immediately with a high CO_2 price (or equivalently, establishing an overly strict near-term emission cap) could be extremely disruptive to the economy. Thus, a policy phase-in is needed to balance the competing objectives of starting at a modest level to avoid excessive near-term disruption, and reaching a more stringent level over a timeframe consistent with environmental objectives. Phase-in periods of 10 to 15 years should allow time for the economy and infrastructure investment to foresee and adapt to moderately high CO_2 prices while avoiding many of the negative economic consequences that would likely accompany a more abrupt imposition of high CO_2 prices.

3.E. MARKET-BASED CO_2 POLICY ALTERNATIVES: ALLOWANCE CAP VS. CO_2 TAX OR FEE

Beyond these general principles, there are a host of policy choices that pose more subtle tradeoffs between cost, administrative feasibility, consideration of uncertainties and the allocation of burdens and risks. Most of the CO_2 policy discussion thus far has focused on the design of a CO_2 allowance cap-and-trade system, either economy-wide or applied to the electricity sector and/or other major emitting sectors. Such policies have been proposed in Congress, sometimes in conjunction with additional controls on SO_2, NO_x, and mercury.[7] A regional system is being implemented by several states in the Northeast (the Regional Greenhouse Gas Initiative – RGGI), and California is moving forward with its own cap-and-trade system. Specific allowance allocation formulas are being debated, including the initial allowance issuance point (e.g. "upstream" vs. "downstream"), inter-sectoral allocations and/or exemptions, and even specific formulas for allocating allowances among electric generators.

While these discussions and debates have yielded some useful insights on policy tradeoffs within the category of allowance-based policies, they often are premised on the assumed inevitability of an allowance cap-and-trade strategy for U.S. greenhouse gas emissions. This premise arises naturally from the previous success of cap-and-trade policies for SO_2 and NO_x in the U.S.; the negotiations for and structure of the Kyoto Protocol; the desire to reach particular emission targets in the near term and a longstanding political aversion to "pollution taxes" (or any taxes, for that matter). Despite the apparent momentum in the direction of a cap-and-trade system for reducing CO_2 emissions, however, recent events in energy markets provide a strong case for examining an alternative approach.

The Role of Uncertainty

The two fundamental market-based mechanisms for controlling emissions are quantity and price approaches.[8] An allowance-based cap-and-trade mechanism (such as the SO_2 and NO_x markets) represents a quantity approach – the emission quantity is set administratively and the market determines the allowance price consistent with that quantity.[9] A tax or fee system represents a price approach – it fixes the price administratively and lets the market determine the emission quantity that is consistent with the emission price. Either approach can be effective and efficient under the right circumstances, because both offer mechanisms to equalize marginal abatement costs across the economy.

Under particular theoretical conditions (including the assumption of perfect certainty regarding abatement costs and other prices, as well as perfect market performance) the emission fee that will lead to a given quantity of emissions would be identical to the allowance price that will result from setting an emission cap at that same quantity. Presumably, before embarking on either a quantity or price approach, policy makers would establish an estimate or target for the corresponding price or quantity that they expect the market to produce. However, such estimates might contain substantial uncertainty as they would be affected by a number of unpredictable factors, including future fuel prices, technology costs and performance, changing patterns of industrial activity, and economic growth rates. The question then becomes whether the quantity uncertainty under a CO_2 fee policy is more or less burdensome than the price uncertainty under a cap-and-trade policy.

Put simply, a cap-based solution poses significant economic risks (allowance prices and overall program costs are highly uncertain) while it assures a specific environmental outcome (i.e., emissions are "capped" at a specific level, at least as long as the economic costs do not become so extreme that the cap is relaxed or repealed). A fee-based policy provides certainty regarding CO_2 costs and therefore much less economic risk, but does not guarantee that particular short-term emission reduction targets will be achieved.

The uncertainty about CO_2 abatement costs under a cap-and-trade system creates two types of economic risks. The first is the substantial uncertainty over the allowance price that would emerge in order to comply with the emission cap, and resulting overall costs to the economy. The second major risk is the prospect for significant volatility in CO_2 prices over time as a result of variation in underlying energy prices, consumer demand, the level of economic growth, and uneven investment in abatement capital. While some short-term CO_2 allowance price volatility might be hedged with financial instruments, long-term volatility is harder to avoid and injects substantial uncertainty into business planning for long-lived investments. Substantial price volatility has been experienced in the early stages of the European Union Emission Trading System (ETS) market for CO_2 emission allowances, producing dramatic swings in asset values and economic outcomes. Uncertainty and volatility can affect investment in numerous ways, including raising the costs of capital (potentially deterring investment in CO_2 abatement) and can contribute to "boom-bust" investment cycles that can be disruptive to markets more generally.[10] In the extreme, CO_2 price uncertainty and volatility could impose a substantial burden on the entire economy.

Many utilities are finding the current era of fuel price uncertainty and volatility a very challenging environment in which to plan generation expansion (or other investments such as transmission) or secure long-term contracts. The potential for uncertainty and volatility in CO_2 prices to compound these challenges should be considered and compared to a potentially more stable and predictable CO_2 price path associated with an emission fee approach. Long-term predictability of a CO_2 price will encourage orderly investment in low-carbon and carbon-capture technologies, since a predictable CO_2 price will provide more certain benefits or returns from investment, reducing the financial risk of R&D and investment.

As for the environmental risk that a CO_2 fee approach may fail to attain a specific emission target in a given year, climate change is a long-term problem that ultimately will depend on cumulative global CO_2 emissions rather than the emissions in any particular year. With a gradually increasing fee, if desired targets are not hit in the first few years of the program, the price will continue to increase and emissions will ultimately decrease. While this may occur a few years later than expected and hoped (or perhaps a few years earlier), that will not substantially affect long-term CO_2 concentrations.

Particularly in the early stages of market development, when little is known about how much CO_2 can be reduced at what cost, it may be worth sacrificing some certainty in short-term CO_2 reductions for greater certainty in the short-term and long-term CO_2 price. Certainty about the CO_2 price may induce greater investment in CO_2 abatement technology and ultimately yield greater long-term emission reductions. Many proponents of ambitious emission targets argue that high allowance prices are unlikely because there are significantly more low-cost abatement opportunities than are generally recognized. If these proponents are correct, then an emission fee approach would yield greater emission reductions than generally expected.

Hybrid Solutions and a "Safety Valve" Allowance Price

It is also possible to combine cap-and-fee features into a hybrid policy structure. A cap-based policy with a "safety valve" feature (a price ceiling) would set an emission cap but make additional allowances available at the safety valve price, allowing the cap to be exceeded if the allowance price reaches the ceiling price. Similarly, a price "floor" would guarantee a minimum CO_2 price that would encourage development and investment in low-CO_2 technologies. A cap-based policy with a ceiling and/or floor price is a hybrid of price and quantity mechanisms that offers many of the economic advantages of a CO_2 fee. It would prevent very high CO_2 prices and limit volatility. By increasing the price ceiling and floor over time, this hybrid approach could be used to phase in an effective policy, much like the increasing CO_2 fee. It could also emulate other features of a desirable program, like being applied economy-wide and upstream on all fossil fuels. Potential disadvantages of a hybrid approach include higher administrative costs (e.g., to develop trading mechanisms) and some residual CO_2 price risk, if the ceiling and floor prices allow too much price variation.

There are several ways in which a safety valve approach differs from a CO_2 fee approach, however. A safety valve policy, because it involves some distribution of allowances, still raises the issue of allocation formulas. This could be contentious, and allocating free allowances would eliminate program revenues that could otherwise be used to assist in further reducing CO_2 and to offset the negative consequences of the policy for customers and vulnerable industries. Also, with a safety valve program auction and trading mechanisms would probably have to be developed in case the CO_2 price is below the safety valve, but these might turn out to be unnecessary administrative burdens if the safety valve is always triggered. Finally, the long-run emission level may be different (assuming that the safety valve price would rise until the emission cap is binding) compared to the case where a higher CO_2 fee encourages emission reductions below the emission cap level.

IV. ANALYSIS OF A CO_2 EMISSION FEE POLICY

In order to illustrate the potential impacts of a gradually increasing CO_2 fee, we examine a policy that begins with a CO_2 price of $10/ton CO_2, increasing $2/ton each year so that in ten years the fee would reach $30/ton (all in real dollars). A $10/ton fee would have generally modest economic impacts, with substantial emission reductions expected to begin in the latter part of the initial decade of the program. We examine below the economic impacts of such a CO_2 price policy, focusing on the electricity sector, and then discuss how the revenues derived from the CO_2 fee could be used to enhance emission reductions and offset consumer impacts.

Power generation accounts for about 40% of total U.S. CO_2 output, and any meaningful CO_2 policy must achieve substantial reductions from this sector. As discussed, recent increases in natural gas price mean that CO_2 price will need to be fairly high – on the order of $30/ton – to cause substantial reductions from the power sector. Even then, much of the reduction would come not from immediate fuel switching in existing electric generators, but rather from what have often been viewed as "second-order" effects – demand reduction caused by higher power prices, and in the longer term, the adoption of lower-carbon technologies for new generation additions.

4.A. CO_2 PRICE AND ELECTRICITY SECTOR EMISSIONS

To estimate the effects of a CO_2 fee on the electric industry and its CO_2 output, we simulated the operation of the Eastern Interconnect.[11] The Eastern Interconnect accounts for about 75% of U.S. generation and an even larger portion of electric CO_2 emissions because of its heavy reliance on coal. We modeled the energy market using marginal-cost pricing and transmission limits on the power flows between areas. Because of the difficulties inherent in long-term forecasts whereby results can be driven by the particular assumptions chosen, we elected to model a "snapshot" of a single year. We used only the current installed base of generating capacity, to avoid speculating about long-run generation additions, and used current expectations of medium to long-term fuel prices (e.g., gas price of about $7), so that the extraordinarily high gas prices prevailing in the near term would not skew the results. This allows us to represent reasonably well the aggregate, high-level effects of a CO_2 fee on the power sector in the early years of a CO_2 policy.

At several levels of CO_2 price ($0, $7, $15, and $30/ton), we calculated the dispatch cost of each generating unit, and then simulated a unit-level dispatch over the year. Initially, demand effects were excluded (i.e., demand was unchanged, despite the CO_2 fee causing higher power prices). This showed, as expected, that there is relatively little fuel switching among existing generators until CO_2 prices become substantial. (Some modest fuel switching does occur even at a low CO_2 price, for example in subregions where coal-fired generation imports are barely economic without a CO_2 price but become uneconomic with a small CO_2 price.) A CO_2 price of around $30/ton CO_2 begins to cause a reasonable amount of fuel switching – though still only enough to reduce electric sector CO_2 output by about 8% from what it would otherwise be, as shown in Figure 2.

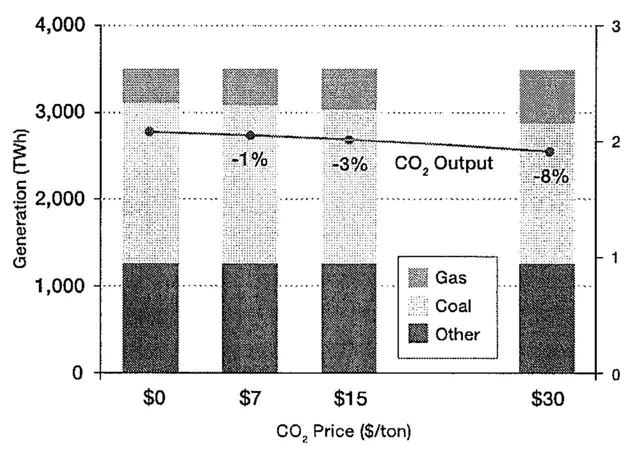


Figure 2: Electric dispatch and CO_2 output vs. CO_2 price (Eastern Interconnect)

4.B. IMPACT ON GENERATION COSTS AND ELECTRICITY PRICE

The mechanisms by which generation costs translate into retail electric prices vary considerably across the country, depending on market organization, generation fuel mix, retail regulation and other factors. Conceptually, a CO_2 price affects power markets by increasing the operating cost of CO_2-emitting (fossil-fired) generators. For a utility under cost-based regulation, the effect is easy to understand – operating costs just increase by the CO_2 cost of emissions. If regulated rates accurately reflect costs, the utility itself will not be affected financially; the additional costs will be passed through to the customer in higher rates (this of course oversimplifies the actual regulatory process, which seldom works so cleanly).[12] Analyzing the effect on operating costs of the initial \$10/ton CO_2 price for several selected utilities showed cost increases ranging from about \$5/MWh for utilities with a relatively low-carbon generation portfolio (substantial gas, nuclear and/or hydro capacity), to over \$11/MWh for those who are heavily coal-based, as shown in Figure 3.[13] Coal-based utilities such as AEP and Allegheny tend to have lower initial rates, and they experience a larger cost increase, both in absolute terms and as a percentage of existing rates. They end up with rates that are still lower than other regions, though by less than with no CO_2 fee.

In a deregulated generation market, hourly prices are set by the bid of the last generator dispatched, so the effect on power price is determined by how the CO_2 price affects the marginal generator's bid. In regions and at times where coal plants are on the margin, the power price will rise by approximately the CO_2 cost of a coal plant (roughly \$1/MWh for each \$1/ton CO_2). When gas is on the margin, the effect is based on a gas plant's CO_2 cost, roughly half the cost increment of a coal plant. So a deregulated coal-fired generator in a region where gas is often on the margin would see its costs go up by more than its revenues, cutting into its operating margin. The same coal plant in a region where coal usually sets the market price would see its revenues and costs rise by about the same amount, for little net effect.

Figure 4 shows the regional average market price effect of a \$10/ton CO_2 price. Regions (and also time periods) where the price-setting margin is dominated by coal experience higher price increases, about \$10/MWh, while those where price is often set by lower-carbon natural gas see a smaller increase, about \$5/MWh. As with the cost-based effect, the largest increases, in absolute as well as percentage terms, occur in coal-dominated regions with lower initial prices. Thus the effect on market price is similar to the effect on cost-based rates, with both in the \$5-10/MWh range.

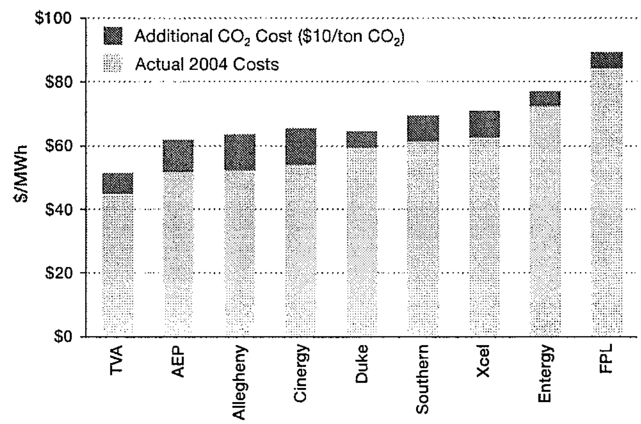


Figure 3: Cost effect of \$10/ton CO_2 fee (selected utilities)

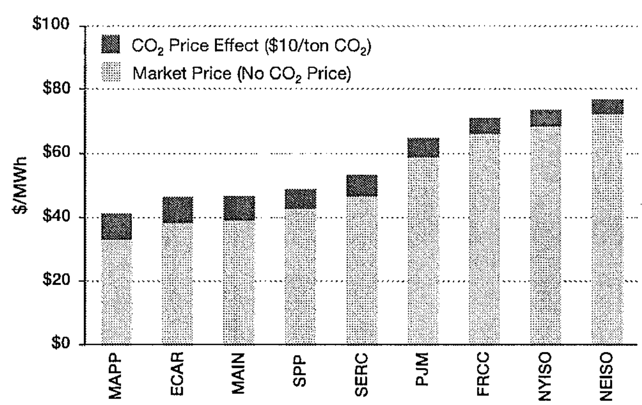


Figure 4: Simulated market price of energy (\$10/ton CO_2 fee)

Considering only the first-order effect of increased dispatch costs (i.e., excluding for now the effect of higher power prices on electric demand), if all generators were unregulated and sold at the competitive market price, they would see, on average, a slight increase in their gross margins due to a \$10/ton CO_2 price, though some generators would see a decrease, as illustrated in Figure 5. Thus, even with no allocations of CO_2 emission rights, half or more of generators would actually benefit from a CO_2 price in a deregulated market, because their revenues would increase by more than their costs. Of course, the generators who fare best are those with substantial amounts of low or zero-carbon generation: gas, nuclear and hydro. Those who would fare less well are those with coal-based generating portfolios, particularly in regions where gas often sets the price.

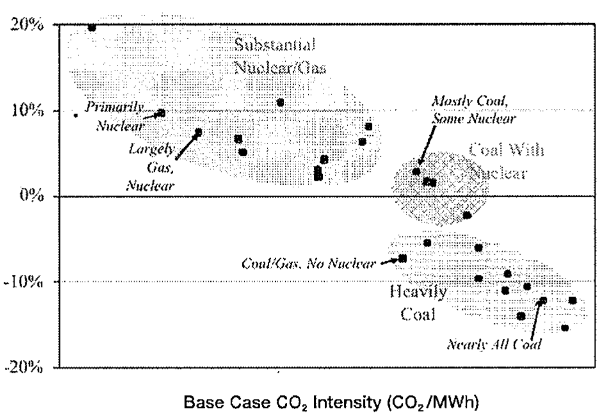


Figure 5: Effect of \$10/ton CO_2 fee on generator gross margins (Eastern Interconnect fleets)

Much discussion of CO_2 policy, particularly in electric utility circles, has focused on whether and how CO_2 electric allowances under a cap-and-trade policy should be allocated to offset the increased costs resulting from a CO_2 policy and/or to shield consumers from electricity price increases. Some utilities advocate allocations to cover nearly 100% of their emissions, while others parties argue that much smaller amounts might be required.[14] Proposals have been put forward by some to base the allowance allocation on historical CO_2 emissions, and by others to base it on MWh output. (Not surprisingly, the former tend to be those with higher historical emissions relative to MWh output, and the latter tend to be the opposite.)

The actual financial effect of a CO_2 price on utilities can be complex, and is not related to easily observable quantities such as CO_2 emissions or MWh output. For deregulated generators, the impact is essentially related to the carbon-intensity of the generator relative to the carbon intensity of the price-setting marginal generators in the region. A generator that is less carbon-intensive than the margin will benefit from a CO_2 price, and vice versa. As mentioned above, if all generators were deregulated, on average they would actually benefit from a CO_2 price because their revenues would increase by more than their costs. Even among those generators who would lose in a deregulated environment, allocations of less than 30% of their emissions would fully offset their losses, and larger allocations would create windfalls.[15]

In fact, most of the generators who might have trouble recovering their costs in a deregulated market are actually regulated and pass their prudently-incurred operating costs through to customers in rates, so there is little direct financial effect to them.[16] Thus, distributing free allocations of allowances generally is unnecessary to protect a utility's financial condition, and attempting to do it through any simple allocation formula (such as historical emissions or MWh output) would be imprecise and somewhat arbitrary. Moreover, substantial allocations to regulated utilities could undermine the goals of the CO_2 policy, by insulating consumers from price signals that would encourage conservation and efficiency. For many deregulated generators, allowance allocations could entail unnecessary wealth transfers and potential windfall gains.

4.C. DEMAND RESPONSE TO ELECTRICITY PRICE INCREASES

Given the substantial effect of a \$10-\$30/ton CO_2 price on both cost-based and market-based prices, it is important to consider potential demand elasticity effects (i.e., higher prices curtail power demand). Several years into the proposed program as CO_2 prices begin to get high, the demand response would be substantial. At \$30/ton CO_2 (the tenth year of the proposed program), resulting retail price increases could lead to demand reductions of about 5% to.10% from projected levels.[17] Simulation modeling shows that this would reduce CO_2 output by about an additional 11%, in addition to the 8% reduction that would be due to the fuel-switching effect alone under a \$30/ton CO_2 fee. This demand response would also partly mitigate the price effects discussed previously.

If it were to occur suddenly, imposing a CO_2 price that would cause a 5-10% demand drop could be quite threatening for utilities (perhaps even more so for other sectors). But with a phased-in policy starting with a low CO_2 price that increased over time, the demand response would manifest as a reduced demand growth rate, which would be far easier to accommodate. For example, if a \$30/ton CO_2 price phased in over ten years reduced demand by 5-10% relative to what it otherwise would have been, this would be similar to a 0.5-1% reduction in annual demand growth over that period. Utilities could accommodate this largely by deferring capacity additions, with relatively little negative impact.

The large emission impact of consumer response compared with fuel switching is a function of both high natural gas prices and the assumed relationship between increased generation costs and higher retail prices. Consumers who curtail demand in response to higher electricity prices still face higher electricity costs and thus a reduction in disposable income, which needs to be considered when designing mechanisms for distributing revenues back into the economy. The role of demand response also provides another contrast to free allowance allocations. To the extent that a free allocation of allowances to electric utilities would prevent retail rates from reflecting the full generation cost burden, consumers are shielded from the economic effects of the program. However, they have no additional incentives for pursuing end-use efficiency and conservation, limiting their participation in providing cost-effective emission reductions. But with a CO_2 fee, increased retail prices promote additional emission reductions from end-use sectors. In the case of an emission cap-and-trade program, an allowance auction that raises retail rates can substantially lower the overall costs of attaining an emission cap compared to the case of a free allocation of allowances that limits retail price impacts but provides no incentives for cost-effective customer demand reductions.[18]

4.D. LONG-RUN TECHNOLOGY SUBSTITUTION IN ELECTRICITY GENERATION

A longer term effect is technology substitution – whether and to what extent imposing a CO_2 price will influence the choice of new generating technologies for capacity expansion, or even cause premature retirement of some existing coal-fired generators. The simulation analyses discussed above showed that a CO_2 fee of \$30/ton would not cause substantial premature retirement of coal units. Because of current high natural gas prices, coal plants are very economical to operate, and highly profitable in deregulated markets. A CO_2 price may reduce this to an extent, but would generally not make coal plants uneconomic or threaten their viability, except perhaps for a small number of old, inefficient units.

In the long run, however, putting a price on CO_2 emissions will encourage the development and installation of lower-carbon technologies for new generation expansion, and this will be one of the primary means of reducing electric sector CO_2 emissions. At current construction costs and fuel prices, conventional coal technology is generally the most economic alternative for new baseload generation. Pulverized coal plants now account for most of the planned baseload capacity over the next decade, in contrast to the last decade when gas-fired combined cycle plants dominated. Non-emitting technologies like wind, solar, hydro, and biomass can fill niches, but for a variety of reasons are often not suited to new large-scale baseload applications.

This situation begins to change with the imposition of a CO_2 fee. A low CO_2 fee, around \$5/ton, would make gas-fired combined cycle generation competitive with conventional coal (gas has about half the CO_2 output), so under the proposed CO_2 fee trajectory starting at $10/ton, new gas capacity would be more economic than new coal capacity in most cases. Very low carbon technologies, such as nuclear or coal IGCC with carbon capture and sequestration, require a substantially higher CO_2 fee to be economic (at least $25/ton and perhaps more, depending on the assumed capital costs of these technologies and fuel prices). However, a steadily rising CO_2 fee would reach this level before long, and technological advances or cost reductions could move up the date at which these alternatives become economic. Figure 6 illustrates a cost comparison of several baseload technology alternatives, showing how the 30-year present value of each technology changes as a function of the CO_2 fee (this assumes a CO_2 fee that is constant in real terms; a fee that increases over time improves the relative performance of the lower-carbon technologies).

V. IMPACTS ON CONSUMERS AND OTHER SECTORS

5.A. OVERALL CONSUMER (HOUSEHOLD) IMPACTS OF CO_2 PRICES

Two significant aspects of how a CO_2 fee would impact households should be considered in designing mitigation measures. The first is that the CO_2 costs in direct energy purchases for household use are only a portion of the overall impact, with an even greater impact coming indirectly through higher prices for a wide range of products and services. The second is that household impacts are regressive; lower income families would pay a greater income share for CO_2 abatement.

Estimates of household energy consumption have consistently placed gasoline and other household direct energy purchases at 7-9% of household income on average.[19] Gasoline accounts for about 47% of energy expenditures,

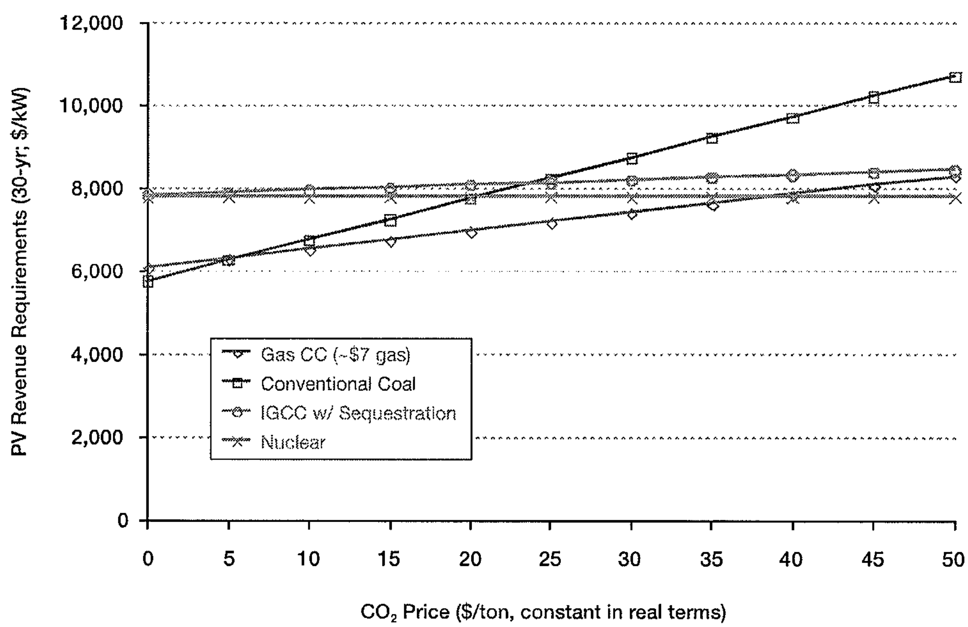


Figure 6: 30-year present value of baseload technology costs vs CO_2 price

with electricity at 35% and home heating (natural gas and heating oil) accounting for the remainder, as shown in Figure 7. Energy costs also affect the prices of a wide array of other goods and services purchased by households. EIA data on sector sources of CO_2 emissions show that household direct energy purchases account for something less than 40% of overall emissions, as seen in Figure 8.[20] Our calculation of the impacts of a $10/ton CO_2 charge, reported in Figure 9, indicates that costs of direct energy purchases (gasoline, natural gas and electricity) would increase on average about $234 annually per household. That is 40% of the approximately $600 annual overall household impact of a $10 CO_2 levy, with the remainder coming through purchases of items other than fuel and electricity.[21] The share attributable to direct purchases of electricity is about $85, less than 15% of the total cost impact.

Abatement-related costs would impose a greater burden on low income families. Recent studies have found that direct energy purchase costs range 8.4-9.2% of income for the poorest households, while for the highest income bracket they range 5.5-6.7%.[22] The working poor are likely to be hardest hit as they have both high home heating and electricity costs as well as high gasoline consumption. These studies and our estimates also indicate that impacts are not evenly distributed by region.

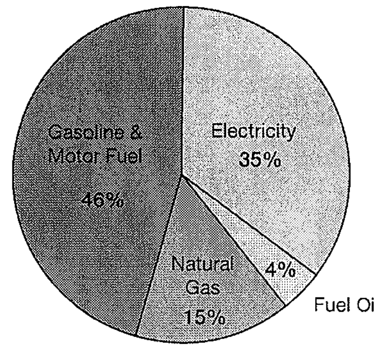


Figure 7: Shares of U.S. household direct energy purchases

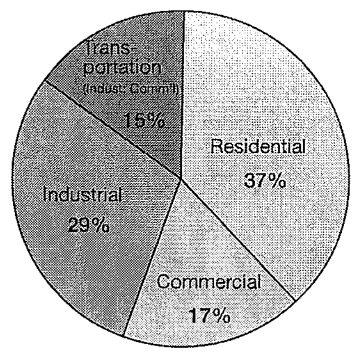


Figure 8: U.S. CO_2 output by sector

Figure 9: Residential energy cost: summary of annual household expenditures

Region	Electricity Cost: Annual Household Consumption (kWh)	Electricity Cost: Base Cost ($)	Electricity Cost: Increase with $10/ton CO_2 ($)	Natural Gas Cost: Annual Household Consumption (000 cf)	Natural Gas Cost: Base Cost ($)	Natural Gas Cost: Increase with $10/ton CO_2 ($)	Gasoline Cost: Annual Household Consumption (gallons)	Gasoline Cost: Base Cost ($)	Gasoline Cost: Increase with $10/ton CO_2 ($)
East North Central	9,206	819	73	95	1,102	56	1,164	2,412	116
East South Central	15,447	1,452	108	60	804	35	1,273	2,619	127
Middle Atlantic	7,799	710	46	75	1,109	44	1,001	2,143	100
New England	7,142	686	34	80	1,234	47	1,086	2,327	109
South Atlantic	13,763	1,184	82	59	1,235	35	1,146	2,419	115
West North Central	10,930	907	90	83	896	49	1,205	2,497	121
West South Central	14,363	1,163	90	57	734	34	1,244	2,541	124
Average			**$75**			**$43**			**$116**

5.B. NATURAL GAS MARKETS

Previous analyses of climate policies based on lower natural gas prices often found that a CO_2 control policy could increase natural gas prices – i.e., that a preference for low-emitting generation fuels would put a premium on gas, the fossil fuel containing the least carbon, increasing gas demand and driving up its price. Our analysis of the electricity sector suggests this is unlikely, at least with current high gas prices. At high gas prices, even a fairly high CO_2 price induces only modest fuel switching to gas, and increased power prices also reduce overall electric demand. In many regions, electricity demand reductions primarily cut gas-fired generation (since gas is often on the margin), offsetting much of the fuel switching effect. Further, an economy-wide program would mean that natural gas becomes more expensive in other sectors, causing reductions in gas demand there. On balance, a CO_2 policy might cause little or no net increase in gas demand, and thus have little or no effect on gas price (beyond the current high levels). In any case, the magnitude of any gas price effect is likely to be within the normal range of commodity price variability.

5.C. TRANSPORTATION

Transportation accounts for about 33% of U.S. CO_2 emissions, with about half of that from household vehicles. Roughly speaking, each $1 per ton of CO_2 price translates into a 1¢ per gallon increase in the price of gasoline or other transport fuel. Thus, the policy proposal discussed here would add about 10¢ per gallon initially and 30¢ per gallon after ten years. Given recent experience, where very high prices for transport fuels have had a small effect on short-run demand, one would not expect this level of CO_2 price to have a large impact on transportation emissions, at least initially. Over time, the fee may encourage more fuel efficient vehicles, and perhaps some changes in driving habits.

There is considerable debate about the overall effectiveness and costs of alternative approaches for reducing overall transport fuel demand – namely tightening corporate average fuel economy (CAFE) standards and/or subsidizing or mandating alternative fuels. Nevertheless, some movement in such a direction appears likely at this time, though probably more out of concern over the national security implications of reliance on imported oil than a desire to reduce greenhouse gas emissions.

A CO_2 fee applied to petroleum-based vehicle fuels would reinforce demand reductions obtained from other policies, and perhaps provide additional environmental benefits. For example, where the production of alternative fuels such as ethanol involves oil or other fossil fuels, the CO_2 price would encourage production technologies that emit less CO_2. In the case of electric or "plug-in" hybrid vehicles (gas-electric hybrids that can be recharged with electricity), the CO_2 fee component of the power price will account for those indirect emissions as well. In other words, while a CO_2 price at levels discussed here may not itself cause substantial direct reductions in transport fuel use, it can help ensure that transport CO_2 reductions achieved by other policies are not partially undone by increased CO_2 emissions elsewhere.

5.D. ENERGY-INTENSIVE INDUSTRIES

Fuel and power consumption by industry accounts for about 30% of total U.S. CO_2 emissions. However, energy consumption is concentrated in a few industries that would face sizable increases in energy costs under an economy-wide CO_2 price. In addition to direct energy costs, indirect energy costs arise in many manufacturing industries that utilize energy intensive intermediate goods such as steel.

Direct Energy and CO_2 Costs

Based on EIA projections for 2010, the industries that emit the most CO_2 per dollar value shipped are cement, steel, chemicals and aluminum, each with more than 1 ton CO_2 per $1,000 value of product shipped.[23] Thus, a $10/ton CO_2 price would impose costs of 1% or more of the value shipped in these industries. Figure 10 shows the overall cost burden for these and other major manufacturing sectors, assuming that projected energy use and CO_2 emissions are not changed by the $10/ton CO_2 fee. Major energy-intensive industries have improved their energy efficiency significantly over the past two decades,

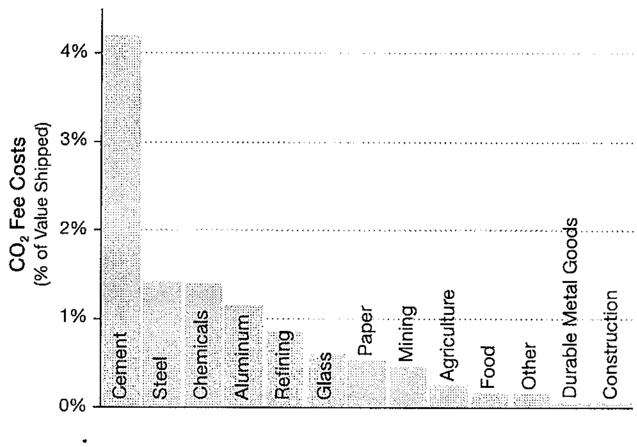


Figure 10: Emission costs of a \$10/ton CO_2 fee, by industry (% of value)

but recently have been challenged by high fuel and power costs. The chemical industry, for example, has suffered under high natural gas and petroleum prices, and now the industry is a net importer when it was previously a major exporter. However, in the case of petrochemicals and related products such as plastics, about two-thirds of the purchased fossil fuel inputs are feedstocks that could be exempt from a CO_2 fee or subject to a credit. Therefore, the CO_2 fee would have a smaller negative impact on the petrochemical industry than would a similar increase in natural gas or petroleum prices.

Indirect Energy Costs

Indirect effects are much harder to estimate, in part because they depend on how much of the CO_2 costs incurred by producers of intermediate goods (e.g. steel) can be passed on to manufacturers of final goods (e.g. automobiles) and ultimately to consumers in the form of higher product prices. Under the assumption that all energy cost increases in intermediate goods production are passed through to final goods manufacturers, one study found that several sectors had much higher indirect costs than direct energy costs.[24] For example, about 90% of the cost increase experienced by automobile manufacturers would arise from increased component prices (steel, plastics, glass etc.). However, in many of these cases the total cost impact was relatively small compared to the value of shipments. In the automobile industry, the overall (direct and indirect) cost impact of an economy-wide \$10/ton CO_2 price would probably be less than \$200 million per year, a very small fraction of the current value of shipments.[25]

Of course, the assumption that all CO_2 costs are passed forward in that analysis would also imply that the primary and intermediate goods manufacturers are neither harmed by the CO_2 price nor contribute any direct emission reductions. Actual inter-industry incidence of CO_2 charges would likely entail a mix of some CO_2 reductions, absorbing some costs that cannot be passed on because of competitive market conditions, and price increases that raise costs of final goods manufacturers. The same situation faces manufacturers of final goods, where strategies that change inputs (energy and non-energy) required can reduce costs and CO_2 emissions, and then the incidence of remaining cost increases depends on the degree to which they can be passed on to final consumers.

5.E. INTERNATIONAL TRADE AND ENERGY-INTENSIVE GOODS

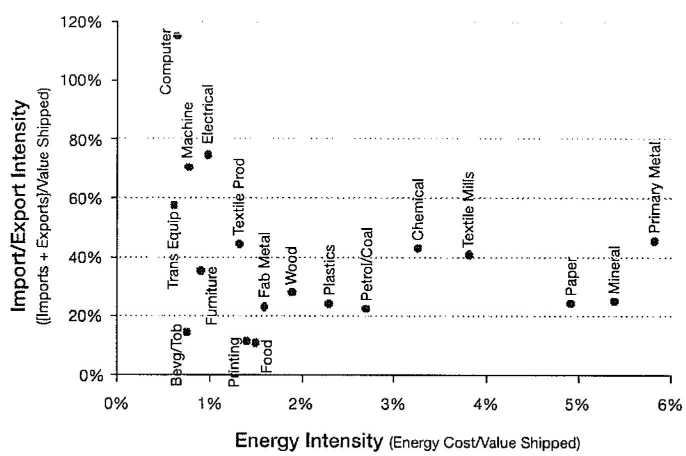
Many energy-intensive products are subject to strong import competition and/or compete abroad in export markets. Because of the international competition, these products face especially price-sensitive demand, which means that cost increases generally cannot be passed on without losing sales, raising the risks of reduced output, employment and profits in these industries.

In a purely domestic context, a change in the mix of goods produced and purchased – as consumers substitute lower-CO_2 goods – helps reduce emissions, and the economic harm from one sector's contraction can be at least partially offset by another sector's expansion. In the case of imports, however, the substitutions may not necessarily lead to reductions in global CO_2 emissions. In fact, it is plausible that CO_2 emitting production could be "exported" to countries without CO_2 controls, causing overall emissions to increase even as domestic production and employment fall. This phenomenon might occur, for example, if the CO_2 costs of domestic steel production and consequent price increases led to an influx of imported steel from countries lacking comparable CO_2 policies but with less efficient production technologies. Therefore, protecting U.S. industry from the trade impacts associated with increased CO_2 costs not only is necessary from an economic competitiveness perspective, it can actually improve global environmental outcomes.

Many energy-intensive industries operate in competitive international markets, characterized by high levels of imports and/or exports, and may require some special protections. Figure 11 depicts energy intensity (energy costs as a percent of value of shipments) and import/export exposure (the value of imports plus exports, as a percent of value of shipments) for various industries in 2004.[26] The most energy-intensive industries (primary metals, non-metallic minerals, paper, textile mills, chemicals, on the right side of the chart) have about 30% or more import/export intensity, indicating a high degree of participation in international markets and potential exposure to international competition. Industries with high energy use and substantial international competition may require specific protections so that the emission "leakage" through increased imports or reduced exports does not frustrate CO_2 policy goals. Allowance allocations are unlikely to be an effective mechanism for this. Since they are a lump-sum transfer, they do not change how the CO_2 price affects a producer's marginal cost. A producer made uneconomic by the CO_2 fee would find that a grant of allowances does not change this fact, and could simply appropriate the value of the allowances, shut down domestic production, and possibly relocate overseas. This might help the producer's shareholders, but would not protect the industry or its labor force and would not reduce global CO_2 emissions.

A potentially better approach would be to make "border tax adjustments" (BTA) to counteract the differences in domestic and foreign treatment of CO_2 emissions. Such an adjustment would be both environmentally and economically appropriate in this case. The additional costs arising from a domestic carbon fee could be rebated to an exporting manufacturer, while a tariff comparable to the carbon fee could be imposed on imports. The General Agreement on Tariffs and Trade (GATT) Article III:2 permits BTA treatment so long as the adjustment is consistent with the domestic tax.[27] As a practical matter, BTAs would have to be calculated for various products in international trade and there are limits to the degree of complexity that BTA can reasonably address. While the CO_2 fee content of a ton of steel may be relatively straightforward to calculate, the CO_2 fee content of an automobile (which largely arises indirectly through component manufacture and not directly in assembly) would be more difficult to determine accurately. Therefore BTAs would be easier to apply, as well as more necessary, in commodity sectors

Figure 11: Energy intensity and international trade exposure by industry



such as chemicals, steel, paper and cement that have high direct energy costs.

VI. PROGRAM REVENUES AND RECYCLING MECHANISMS

6.A. PROGRAM REVENUES

Overall CO_2 emissions can be accurately forecasted in the near term, with annual variability due to weather, energy prices changes, and economic growth rates well within ± 5%. Even if a gradually increasing CO_2 fee began to affect emission levels, the changes would be fairly modest from year-to-year and near-term emission forecasts could still be fairly accurate. Coupled with a known CO_2 fee rate, revenues from an upstream CO_2 fee would be predictable in advance and fairly stable from year-to-year. This stands in marked contrast to the proceeds of CO_2 allowance auctions, which would have a known quantity of emission allowances but where the market-clearing price could be highly uncertain and would likely exhibit volatility over time as a function of a changing cap, shifting energy prices and other factors that influence abatement costs. The relatively predictable and stable revenues arising from a CO_2 fee could greatly simplify the design and management of mitigation policies, an advantage that has not been widely considered in CO_2 policy debates.

According to recent EIA data, U.S. greenhouse gas emissions were a little over 7 billion tons of CO_2 equivalents in 2005. Therefore a $10/ton fee would generate a bit more than $70 billion in gross revenues.[28] While this is a substantial sum by any measure, it is only about one-half percent of the $12.5 trillion 2005 GDP (and decreasing, as emissions are expected to grow more slowly than GDP). In fact, the revenue generated would account for most of the overall economic burden of the policy – but would also represent a funding stream that can be returned to the economy in ways that enhance CO_2 reductions and mitigate most of the policy's consumer burden.

A policy that increased the CO_2 fee by $2/ton each year, reaching $30/ton in ten years, would initially show increased revenues from the increasing fee and growing CO_2 emissions, but in the longer run the fee would begin to curb emission growth rates and ultimately reduce emissions.

6.B. MECHANISMS FOR RETURNING REVENUES TO THE ECONOMY

Although $70 billion is not large compared with the size of the U.S. economy, it still represents a significant burden on consumers, one which would approximately double in the first five years and nearly triple in ten years as the fee is gradually raised. Assuming that the objective of the CO_2 fee is to encourage cost-effective emission reductions, and not increase government tax receipts, revenues should not go into the general fund. Instead, mechanisms to "recycle" the revenues back into the economy should be an integral part of the policy.

Some have suggested that in addition to the environmental benefits, a CO_2 policy may offer a source of revenue that could be utilized to eliminate flaws and inefficiencies in the current tax code. However, many of the potential tax reforms suggested – such as reducing taxes on capital and corporate income – are themselves highly controversial, and tying the implementation of CO_2 policy to attaining some consensus on fundamental tax reform may simply cause both efforts to stall. Because of this, it may be worth exploring less ideological policies for returning revenues to the economy and consumers, targeting them specifically to reducing the burden of the CO_2 prices and enhancing emission reduction opportunities. In particular, mindful of the regressivity of CO_2 fees, revenue recycling policies that would favor lower-income consumers should be given strong consideration.

Policies to Enhance CO_2 Emission Reductions

Increased research and development into promising technologies could hasten advances in energy efficiency, renewables or CO_2 capture and sequestration. A CO_2 fee would clearly improve the returns expected from such R&D, and thus encourage more private-sector R&D activity in these areas. Nevertheless, subsidizing R&D investment in low- or zero-carbon energy sources could further promote their adoption and therefore accelerate emission reductions expected under the policy as well as reduce ultimate consumer costs.

The U.S. government already spends several billion dollars per year on such R&D, which could be enhanced significantly by dedicating a portion of CO_2 revenues to such efforts. Of course, such efforts have a mixed record in the past, and mechanisms must be identified to reward success without trying in advance to pick the likely technological winners or displace private-sector R&D that might otherwise occur.

Alternatively, tax incentives could be given for investments that reduce energy use or CO_2 emissions, which would promote additional emission reductions under the CO_2 fee and also lower the overall burden on companies and consumers. Tax incentives must be structured carefully to maximize the incentives for investments while limiting windfalls to those companies or consumers who would otherwise undertake such investments even without the additional tax benefit.

Policies to Restore Consumers' Income

The incidence of CO_2 fees will fall primarily on consumers through higher energy costs and higher prices for goods and services. While this would provide appropriate incentives to reduce energy use and alter purchasing patterns, consumers would experience a reduction in real disposable income. Because consumers would bear most of the burden, it seems reasonable to target most of the program revenues to offset increased consumer costs, with particular attention to the regressivity of the CO_2 fee.

The simplest method would be uniform "lump-sum" payments to consumers. This would be progressive, as the uniform amount would represent a much larger fraction of household income or expenditures for lower income consumers. The CO_2 policy may even make some consumers better off – the payment might more than compensate energy efficient consumers for their CO_2 expenditures. There are roughly 130 million individual income tax filings per year; $70 billion per year in (gross) revenues would provide a uniform annual payment of over $500 per year to each tax filer, or about $230 per year for each individual. These amounts could be adjusted quite easily to reflect changes in revenues as the CO_2 fee gradually increases and ultimately, CO_2 emissions decrease.

Beyond lump-sum payments, there are a number of other ways to structure a progressive payment through the tax code, including:

- Expanding the Earned Income Tax Credit (EITC)
- Raising standard deductions and personal exemption levels
- Reducing payroll tax rates (FICA)
- Reducing marginal tax rates in lowest brackets

Each of these has drawbacks and limitations. For instance, not everyone eligible for the EITC actually claims it, and many low-income workers do not pay federal income tax, so raising standard deductions or reducing marginal tax rates may not accurately compensate for higher CO_2 costs. Nevertheless, some combination of these elements could be structured to provide an approximately equitable return of CO_2 fee revenues to those who are disproportionately harmed.

VII. CONCLUSION

The policy discussion surrounding CO_2 emissions has progressed to the point where concrete proposals are being debated, but many of these debates are focused on the details of implementing a particular approach – namely an allowance cap-and-trade policy. However, our analysis suggests that the debate should be opened up to seriously consider an alternative approach – a gradually increasing fee on CO_2 emissions combined with mechanisms to return the revenues to affected consumers. On balance, we conclude that a fee-based policy demonstrates considerable advantages in terms of more manageable economic risks and more transparent opportunities to mitigate adverse impacts. Further, the economic certainty of a fee-based policy would allow greater incentives for CO_2 reduction with less risk to the economy, quite likely leading to greater emission reductions in the long run.

ENDNOTES

1. Since CO_2 from the combustion of fossil fuels is by far the largest source of the anthropogenic greenhouse gases that contribute to global climate change, this paper focuses on CO_2. Of course, an efficient policy should similarly cover other greenhouse gases, such as methane and N_2O.

2. See, for example, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, (EIA, October 1998) which found that 68% to 75% of CO_2 emission reductions would occur in the electric generation sector.

3. Some discussions of greenhouse gas emissions refer to carbon (C), while others refer to CO_2. One ton of carbon is equivalent to 3.67 tons of CO_2, so multiply by 3.67 to translate between a CO_2 price and a carbon price. For example, \$5/ton CO_2 is approximately equal to \$18/ton carbon. Also, many analysts use metric tons (1,000 kilograms), which is 2,205 lb and thus 10% larger than the short tons used in this report.

4. Delivered gas prices have been even higher recently; \$7/MMBtu reflects current prices and a mid-range of forecasts for the next few years, recognizing that gas price forecasts are frequently changed and exhibit very broad ranges.

5. For example, see Pizer, et. al. "Modeling Costs of Economy-wide versus Sectoral Climate Policies Using Combined Aggregate-Sectoral Models," Resources for the Future, Working Paper, March 2003.

6. Tim Hargrave, U.S. Carbon Emissions Trading: Description of an Upstream Approach, Washington, DC: Center for Clean Air Policy, 1998.

7. Recent bills introduced in Congress all involve, to some degree or another, a cap-and-trade approach to CO_2 emissions.

8. A good discussion of these approaches can be found in William Pizer, "Choosing Price or Quantity Controls for Greenhouse Gases" *in Climate Change Economics and Policy, An RFF Anthology*, Resources for The Future, 2001.

9. Two primary methods of distributing allowances are often discussed: a free allocation to market participants and an auction. Because allowances have economic value, a free allocation raises the very contentious issue of the allocation formula and the resulting distribution of benefits. An allowance auction would also generate a market-clearing price for allowances, and participants could trade allowances later as a function of changing prices or financial strategies. However, no initial "windfall" benefit is generated as the original allowance is purchased rather than granted. Although the auction would generate revenues similar to a CO_2 tax, uncertainty and volatility in CO_2 allowance prices over time would reduce the predictability and/or stability of those revenue streams compared to those generated under a CO_2 tax policy.

10. Fluctuating allowance prices can generate "boom-bust" investment cycles if market participants react to current prices similarly – i.e. when prices rise, investments in CO_2 abatement increase to an aggregate level that cuts CO_2 emissions enough to depress allowance prices, leading to a period of less investment in CO_2 abatement during which emissions rise enough to put pressure on allowance prices, repeating the cycle.

11. The simulation analyses were performed by the FPLE Market Analysis Group using the Aurora production simulation model.

12. It is worth noting that a gradually increasing and predictable CO_2 fee would probably be less challenging for utility regulators to pass through accurately in rates than a less transparent and less certain set of costs and/or assets derived from the valuation of utility allowance holdings through time.

13. This calculation is an approximation; it simply applies a \$10/ton CO_2 cost to each utility's actual 2004 emissions. To the extent the CO_2 price alters dispatch toward lower-carbon generators, e.g., causing coal plants to operate less and gas plants more, the actual effect will be smaller than this. A different CO_2 price would yield a very roughly proportional effect (e.g., a \$15/ton CO_2 price would have about 1.5 times the effect of \$10/ton), though as CO_2 prices get high enough to cause fuel switching, the effect would be less than proportional.

14. For example, researchers at Resources for the Future concluded that utilities needed, on average, allocations equal to just 7.5% of their emissions to offset the increased costs. See Dallas Burtraw, Karen Palmer, Ranjit Bharvirkar and Anthony Paul, "The Effect on Asset Values of the Allocation of Carbon Dioxide Emission Allowances," Resources for the Future, Discussion Paper 02–15, March 2002.

15. The only situation where 100% allocation would be required to indemnify a generator is where an unregulated fossil-fired generator operates in a market where the price-setting margin is dominated entirely by carbon-free generators. Such a situation does not exist in the U.S. Even in markets with substantial amounts of carbon-free generation (e.g., hydro, nuclear), the price-setting units on the margin are almost always fossil fueled.

16. Again, this presumes efficient regulation and no rate caps or long-term contracts that cannot be reopened under the policy. A CO_2 policy announced well in advance of implementation or compliance deadlines would reduce the need to re-open contracts or revisit rate caps, as most would expire in the interim.

17. Several studies have concluded that the elasticity of electric demand is in the range of -.2 to -.5 (typically less in the short run,

more in the long run, and varying across customer classes). That is, a 1% increase in power price will result in about a 0.2% to 0.5% decrease in electric demand, all else equal. In modeling a policy that imposes a price on CO_2, other factors are of course not equal. The price of alternative fuels also increases, which would reduce the observed elasticity. The observed percentage increase in wholesale price would translate to a smaller percentage effect on retail prices, further damping the overall effect. Also, elasticities are defined and measured assuming a small price deviation, whereas in this case the price effect is substantial; it is not clear whether this would magnify or dampen the resulting elasticity response. Simulation analyses used regional elasticity estimates based on a study of regional energy elasticities. (Bernstein, Mark A. and Griffin, James; *Regional Differences in the Price-Elasticity of Demand for Energy*, RAND, 2005.) High and low-elasticity regions were identified, and assigned elasticities of -.25 and -.125, respectively. These elasticities were about half the reported regional elasticities, the level judged reasonable considering the effects discussed above. Note that these estimates of demand reduction presume no substantial new electric demand is created by other sectors switching to electricity as a fuel (e.g., plug-in hybrid autos). Such switching to electric power is a real possibility in a CO_2-constrained world since there are plausible low-carbon electric technologies (nuclear, sequestration, renewables) but there may be fewer such options in other sectors, leading other sectors to switch to electricity to avoid CO_2 costs.

18. Researchers at Resources for the Future have found that the overall cost of meeting an emission target can be roughly double under a free allocation of permits compared to an auction of allowances that translates more directly into electricity price increases. See, e.g., Burtraw, et al., "The Effect of Allowance Allocation on the Cost of Carbon Emission Trading," Discussion Paper 01-30, Resources for the Future, August 2001.

19. *Who Gains and Who Pays under Carbon-Allowance Trading?*, Congressional Budget Office, June 2000, Table 3 (7%); Cashin, David B., McGranahan, Leslie, Household Energy Expenditures, 1982-2004, Chicago Fed Letter, Federal Reserve Bank of Chicago, No. 227, June 2006, p. 1, Figure 3.

20. Energy Information Administration, *Emissions of Greenhouse Gasses in the United States 2004*, December 2005.

21. The $234 figure was calculated based upon households with natural gas heating; the average for households relying upon fuel oil would be slightly higher due to the higher carbon content of oil. The overall household impact was established by dividing the $70 billion total impact of the $10/ton CO_2 levy by an estimated 115 to 120 million U.S. households. If consumption levels remain unchanged, by the time the CO_2 fee reached $30/ton the effect would triple to $702. However, this likely overstates the effect, since such an increase in energy costs would likely trigger mitigating changes in consumption.

22. CBO Report, Table 3; Chicago Fed Report, Figure 4.

23. The EIA emission projections include the CO_2 emitted from electricity consumed by each sector. The very large figure for cement includes CO_2 emitted in the production process that is not due to fossil fuel combustion, and the CO_2 emission figure for chemicals excludes fossil fuels used for feedstocks.

24. See Richard D. Morgenstern, et. al., "The Near-Term Impacts of Carbon Mitigation Policies on Manufacturing Industries" Resources for the Future Discussion Paper, March 2002, for detailed estimates of impacts including indirect effects. This paper provides an illustrative distribution of direct and indirect costs, but the results do not reflect any exemption for non-fuel uses in assessing the carbon fee; this overstates the cost impacts for various chemical and plastics manufacturing sectors compared to the policy evaluated here.

25. See Morgenstern, et. al., "The Near-Term Impacts of Carbon Mitigation Policies on Manufacturing Industries," Resources for the Future Discussion Paper, March 2002. Table 3 shows an overall cost of $40.3 million (in 1992 dollars) per every dollar of carbon fee assessed in industry code 590301 "Motor vehicles and passenger car bodies." On a $/$CO_2$ basis, this would be about $11 million per year for each dollar of CO_2 fee, or about $110 million for a $10/ton fee (all in 1992 dollars).

26. 2004 is the most recent year for which comprehensive data is available. Import and export figures are taken from international trade statistics, and employ a different classification scheme than used in other data. Nevertheless, the primary categories are similar.

27. See J. Andrew Hoerner "Burdens and Benefits of Environmental Tax Reform: An Analysis of Distribution by Industry" Chapter 6, Center for a Sustainable Economy and Redefining Progress, February, 2000. Although CO_2 taxes or fees are not candidates for BTA treatment under current rules, the WTO recognizes the importance of revisiting and potentially changing the rules in this context. The prospect for BTA mitigation of trade distortions are probably better under an explicit CO_2 fee than an under allowance cap-and-trade system; calculating the embedded cost of CO_2 is much more transparent under a fee than it would be in an allowance system, where allowance values may fluctuate over time.

28. Actual net revenues might be somewhat lower, depending on interactions with other taxes. For example, if a company could not raise prices to reflect higher energy costs, then its profits would fall, reducing corporate income taxes and personal income taxes on dividends, offsetting some of the CO_2 revenue. Estimates by the Joint Tax Committee for similar taxes suggest that net revenues are about 80% of gross, which would yield roughly $55 billion of net revenues in this case.

Exhibit B

Telecommunications • Litigation • Finance • Environment • Energy

U.S. Climate Policy

Effects on Business and the Environment

The Conference Board

September 26-28, 2007

Dean M. Murphy

The Brattle Group

Agenda

If we decide to cut U.S. CO_2, how would we do it?

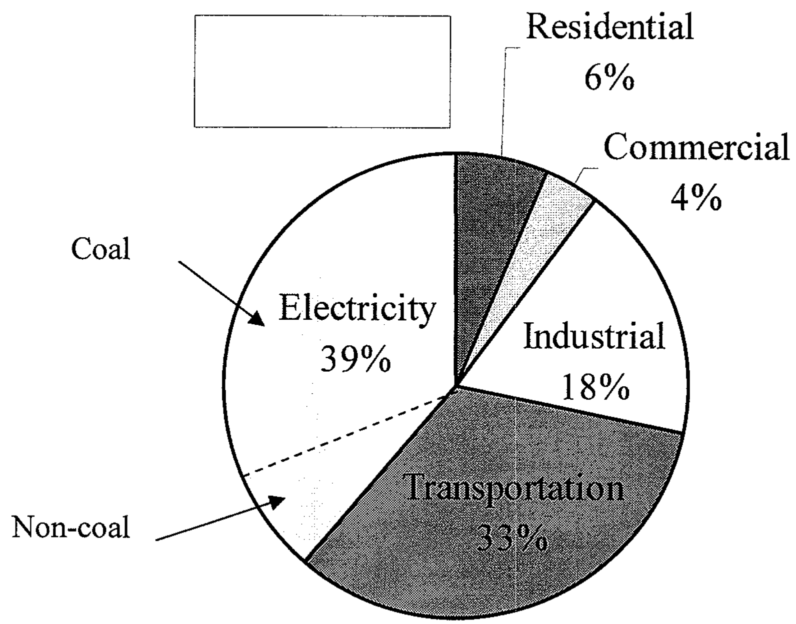
- What sectors?
- What policy mechanisms?
- What would be their effects?
- Costs to business and consumers?
- Regional effects?

Getting to a Low-Carbon Economy

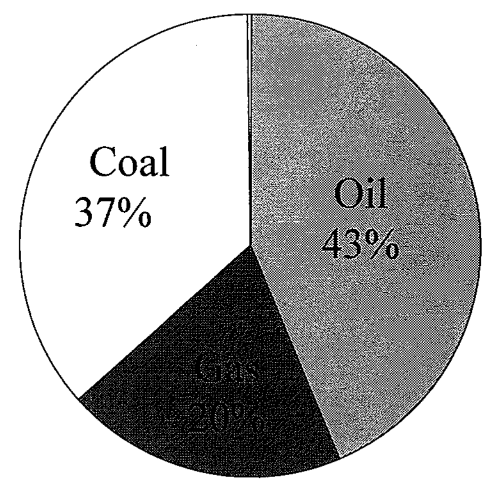
U.S. CO_2 Emissions

Primary CO_2 sectors: electric power and transport

Sector Shares



Fuel Shares



Note: Excludes non-CO_2 GHGs (~15% of total GHG emissions)

Mandatory, Market-based Climate Policy

"Pricing carbon" is a key element of climate policy

Control quantity: Cap-and-trade, aka emissions trading

- Cap limits CO_2 emissions
- Trading creates market for CO_2 emission rights
- Allowances distributed (allocated free and/or auctioned)
- Quantity set by regulation; market determines price

Control price: CO_2 fee, aka carbon tax

- Impose fee on emissions (e.g., on carbon content of fossil fuel)
- Tax credits for certified CO_2 offsets (e.g., sequestration)
- Substantial revenues available to reduce CO_2, mitigate impacts
- Price set by regulation; market determines quantity

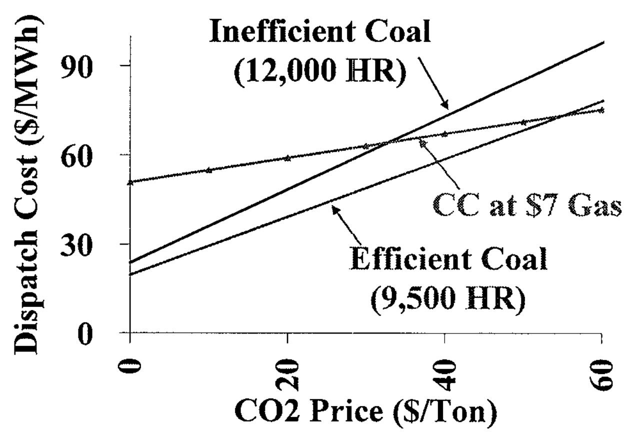
In Power Sector, Coal is King

Existing coal plants are very profitable

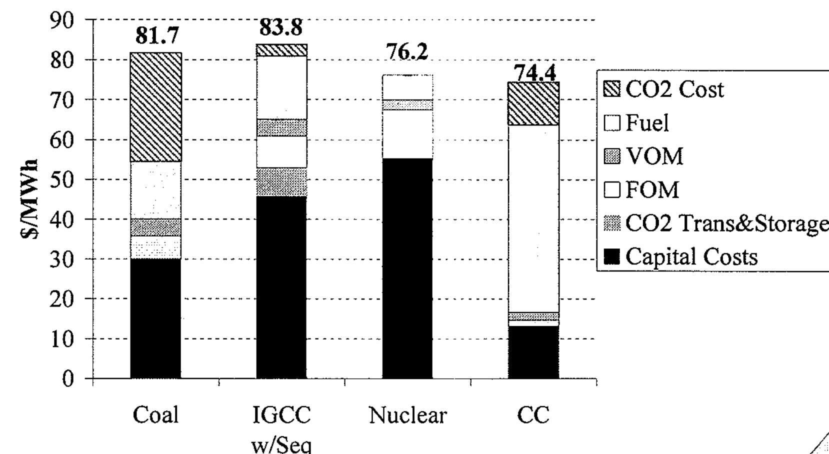
Coal is clear choice for new capacity

- $30/t CO_2 (or more) is needed to make low-CO_2 investment and operation economic

Dispatch Switching
Existing Plants



New Generating Capacity
($30/t CO_2)



Must Retire* Existing Plants to Reduce CO_2

But few retirements are forecast

- Though average age is 35 years, only 2% of existing coal is forecast to retire by 2030 (EIA Reference Case)

Early retirement uneconomic unless CO_2 price high

- Highly profitable at high (gas-driven) power prices
- $40-60/ton CO_2 price needed to retire existing units
- Use targeted subsidies for early retirement?

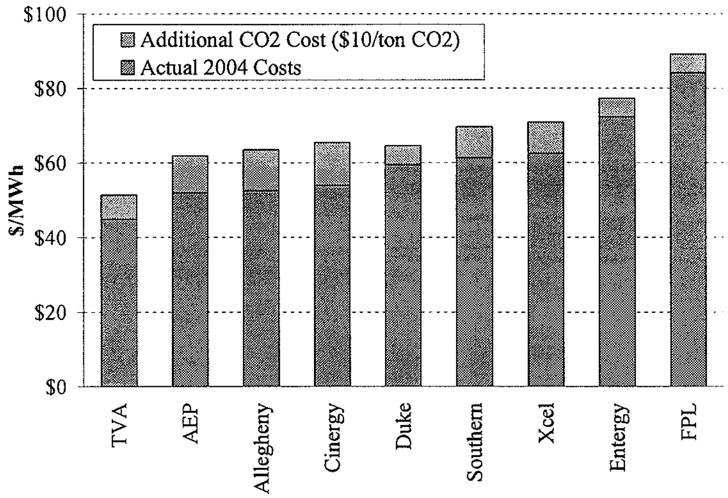
*** Or retrofit for carbon sequestration; economics are similar to retirement**

Carbon Cost Effects: Power Sector

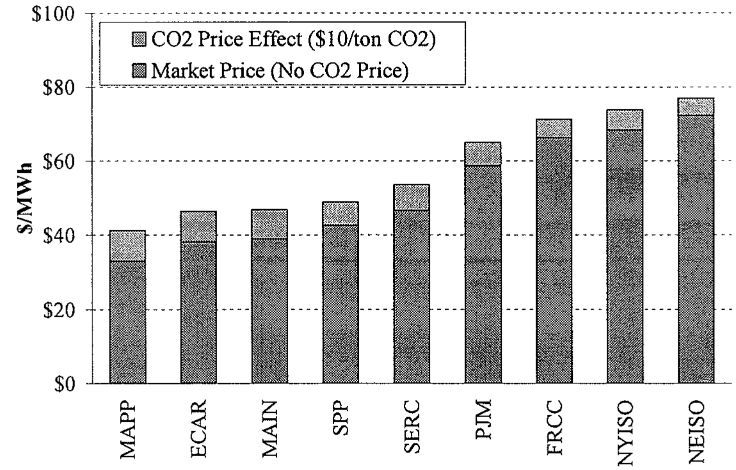
$10/ton CO_2 = $5-10/MWh (+5-10% delivered)

- Inexpensive coal generation hit hardest; effect is generally larger where power is initially cheaper

Cost Effect



Market Price Effect



- Higher CO_2 price has less-than-proportional effect

Carbon Costs Flow Through to Consumers

Market dynamics and regulation have similar effects

- Regulated utilities: cost-of-service regulation
- Deregulated markets: price rises with carbon cost
  - Though costs pass through imperfectly
  - Many winners, a few losers (assuming no compensation)

Large free allocations are unnecessary

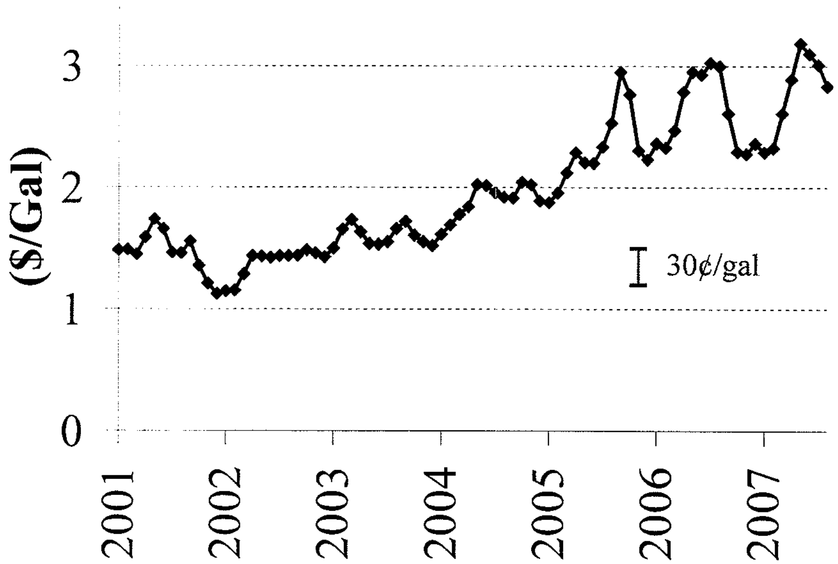
- Windfall to deregulated producers (as in EU)
- Prevents demand response by holding price down
  - Better to allow price to rise, compensate consumers directly

Transport Sector is Insensitive to CO_2 Price

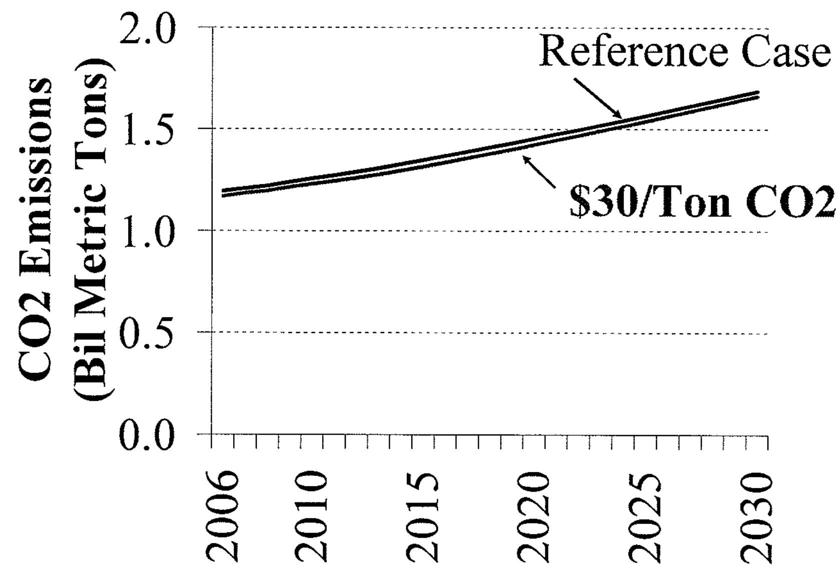
Even \$30/t CO_2 increases gasoline price only modestly

- Adds ~30¢/gallon (+10%)

Gasoline Price



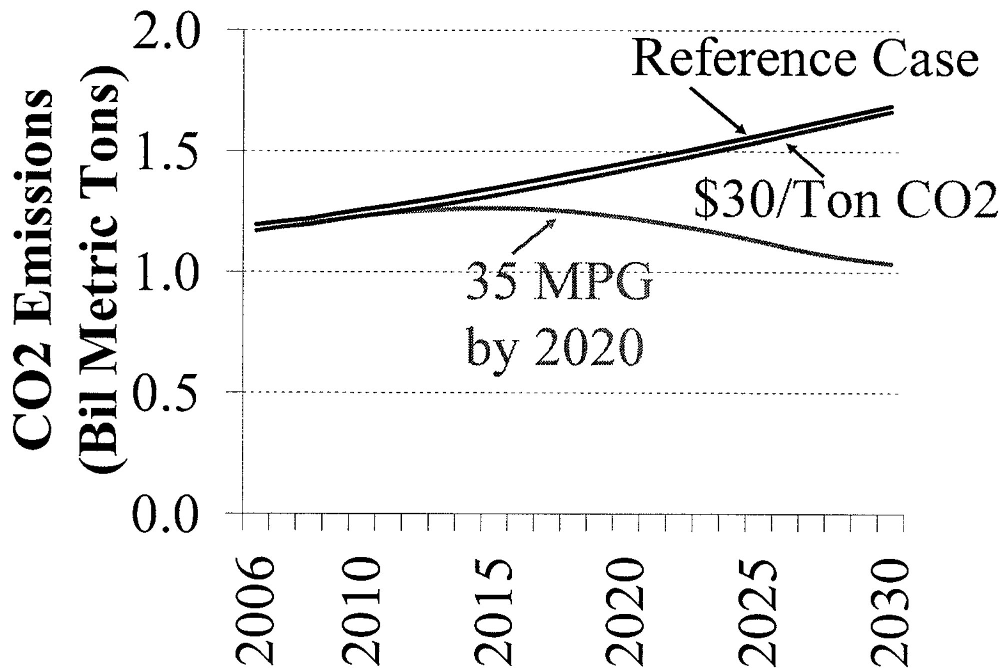
LDV CO_2 Emissions



But Mileage Standards Cut CO_2 Substantially

Senate energy bill: 35 mpg by 2020

LDV CO_2 Emissions



- Biofuels may also play an important role

Getting to a Low-Carbon Economy

Energy infrastructure is long-lived

- Need predictable, well-understood long-term policy

Power sector – put a price on CO_2

- $30/ton and more, with confidence and within planning horizon

Transport sector – efficiency standards

- CO_2 price will be too little, too late

R&D support is crucial (though by itself insufficient)

Cap & Trade, or a Carbon Tax?

CO_2 <u>price</u> drives investment and behavior

- Long-run certainty and stability in CO_2 price encourage rational investment
  - Minimizes overall costs and disruption
- Tax easily phased in to facilitate smooth transition

Tax has other advantages

- Less susceptible to political manipulation
  - Avoids windfalls, other problems of free allocations
- Revenue stream to cut CO_2, compensate consumers
- Carbon tax does not have most "tax" problems

Policy Proposal

Increasing carbon tax (or modified cap-and-trade)

- E.g., start at $10/ton, increase $2 each year
- Phases in gradually: long-term CO_2 price known
  - Time to react; clarity on what to react to
- Other features:
  - Economy-wide
  - Limited transitional protections
  - Revenue neutral – return balance to consumers

Transport sector efficiency (and biofuels?)

- Don't wait for reductions induced by CO_2 price
- Possibly electrification, if power de-carbonized

Exhibit C

COMMENTS OF ENTERGY CORPORATION ON THE MASSACHUSETTS DEPARTMENT OF ENVIRONMENTAL PROTECTION'S DRAFT 310 CMR 7.70: CO_2 BUDGET TRADING PROGRAM REGULATIONS, DRAFT REVISIONS TO 310 CMR 7.29: EMISSIONS STANDARDS FOR POWER PLANTS REGULATIONS, DRAFT REVISIONS TO 310 CMR 7.00 APPENDIX B(7): EMISSIONS BANKING, TRADING AND AVERAGING REGULATIONS AND THE MASSACHUSETTS DIVISION OF ENERGY RESOURCES' DRAFT 225 CMR 13.00: CO_2 BUDGET TRADING PROGRAM AUCTION REGULATIONS

Introduction

Entergy Corporation and its direct and indirect subsidiaries, including Entergy Nuclear Operations, Inc. and Entergy Nuclear Generation Company, LLC (collectively, "Entergy") respectfully submit these comments in response to the Commonwealth of Massachusetts Department of Environmental Protection's (the "Department") draft 310 CMR 7.70: CO_2 Budget Trading Program regulations, draft revisions to 310 CMR 7.29: Emissions Standards for Power Plants regulations, draft revisions to 310 CMR 7.00 Appendix B(7): Emission Banking, Trading and Averaging regulations and the Division of Energy Resources' (the "Division") draft 225 CMR 13.00: CO_2 Budget Trading Program Auction regulations (collectively, the "Draft Regulations"). We understand that the Draft Regulations, which were provided for public comment on August 10, 2007, constitute Massachusetts' proposed implementation of the Regional Greenhouse Gas Initiative ("RGGI") Model Rule in the Commonwealth. Entergy appreciates this opportunity to provide comments on the Draft Regulations in accordance with the Commonwealth's rulemaking procedures outlined in M.G.L. ch. 30A, and the substantial strides that the Division and Department (collectively, the "Commonwealth") have made in developing a viable CO_2 program.

As detailed below, Entergy has developed a thorough understanding of the complexities of creating a successful cap-and-trade program for CO_2 emissions that appropriately balances important environmental objectives and an affordable, reliable and diverse supply of electricity for the Commonwealth. Entergy therefore greatly appreciates the Commonwealth's initiative in the area of CO_2 regulation and the efforts that went into preparing the Draft Regulations, as well as the opportunity to submit these comments. In particular, Entergy herein proposes an innovative new mechanism for both advancing important climate change initiatives and ensuring that the Commonwealth's most needy are able to afford the resulting electricity.

Background

By way of background, in 1999, Entergy acquired, and now owns and operates the Pilgrim Nuclear Power Station ("Pilgrim"), a 670 megawatt (MW) electric generation facility in Plymouth, Massachusetts. Pilgrim has been operating and providing electricity for the Commonwealth since 1972, and is the only operating commercial nuclear station located in Massachusetts. In addition to its critical contribution to the New England power supply, Pilgrim provides an important and too-long unrecognized environmental benefit to Massachusetts. Since the 1970s, Pilgrim and other nuclear stations have produced reliable "base-load" electricity without emitting carbon dioxide ("CO_2"), sulfur dioxide, nitrous oxides or mercury from their core electric-generating activities. The Nuclear Energy Institute ("NEI") concluded that Pilgrim's operations avoided approximately 3.37 million metric tons of CO_2 in 2006,[1] which represents approximately 13.9% of Massachusetts' initial annual budget of 26,660,204 short tons of CO_2 emission allowances under the RGGI Model Rule. In other words, but for Pilgrim's daily operations, Massachusetts's task of reducing CO_2 would be substantially more difficult to achieve.

Entergy also owns and operates facilities within other states that are participating with Massachusetts in RGGI. (Currently, the other "Participating States" are Connecticut, Delaware, Maine, Maryland, New Hampshire, New Jersey, New York, Rhode Island and Vermont.) Specifically, in New York, Entergy owns and operates three nuclear stations with a cumulative capacity of 2,775 MW, representing approximately 16% of New York State's power supply. In Vermont, Entergy owns and operates the Vermont Yankee Station, a 650 MW nuclear electric generation facility that produces more than 72% of the electricity produced within Vermont. As stated by the United States Department of Energy ("DOE"), the emission-free power from Vermont Yankee, which avoided approximately 2.95 million metric tons of CO_2 emissions in 2006, "has to be considered a significant factor" in Vermont's status as the state with the cleanest air in the nation.[2]

On a broader geographic scale, Entergy is the nation's second largest owner and operator of nuclear-fueled generation facilities, and owns or operates twelve (12) nuclear units that contribute approximately 10,467 MW of nuclear-powered electricity to American consumers. In 2006 alone, Entergy's nuclear operations avoided approximately 68 million short tons of CO_2 emissions.[3] Entergy brings to nuclear operations a proven expertise and commitment to safe, secure and cost-effective energy production that offers significant environmental and public-health benefits. Likewise, Entergy is committed to advancing renewable-power generation and already includes in its fleet substantial wind-turbine projects (in Iowa and Texas) and several hydro-electric projects (in Arkansas and Texas). Additional information about Entergy's fleet and renewable generation projects is available at http://www.entergy.com/content/operations_information/fossil_renewable_portfolio.pdf. In addition to its nuclear-powered and renewable fleet, Entergy owns or operates numerous fossil-fuel facilities, contributing to Entergy's world-wide generation of over 30,000 MW. In the context of fossil-fuel facilities, Entergy is striving for innovative new technology, such as its multi-fired Little Gypsy re-powering project in Montz, Louisiana, capable of meeting reliability and affordability goals.

Entergy is a recognized leader in efforts to combat climate change. As one of the largest producers of electric power in the United States, with both nuclear and fossil-fuel facilities in its fleet, Entergy long has embraced its leadership role in improving air quality and redressing climate change. Well before climate change was a household word, Entergy led the electric

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[1] *See* Nuclear Energy Institute, "Emissions Avoided by the U.S. Nuclear Industry: State by State, 2006" (Apr. 2007) *available at* http://nei.org/filefolder/emissions_avoided_by_the_u.s._nuclear_industry_state.xls

[2] *See* id. and http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/reactsum.html

[3] *See* Entergy's 2006 Sustainability Report, *available at* http://www.entergy.com/content/our_community/pdfs/sustainability_report_06.pdf

industry and American boardrooms by making a voluntary public commitment to stabilize company CO_2 emissions at 2000 levels through 2005. Cumulatively, through 2005, Entergy reduced emissions 23%, while increasing electric sales by 21% over the same period, thus demonstrating that growth could accompany innovative environmental decision-making. In 2006, Entergy expanded its commitment to stabilize CO_2 emissions at a level 20% below the 2000 levels for years 2006 through 2010. Entergy's 2006 climate-related projects included the acquisition of 300,000 metric tons of Greenhouse Gas ("GHG")-emission reductions retired as part of Entergy's voluntary emission-reduction initiative. Cumulatively through 2006, Entergy has reduced it carbon footprint by almost 30% to a level near 1990 emissions.

Furthermore and importantly for this rulemaking, Entergy has been an active stakeholder in and vocal supporter of the multi-year development process of RGGI, a frequent commenter in state-led initiatives, such as this one, and, most notably, the company that broke ranks with industry to join the Commonwealth in successfully pursuing mandatory CO_2 regulations by the United States Environmental Protection Agency ("EPA") before the United States Supreme Court. The Court's decision, in Massachusetts, *et al.*, v. EPA, requires EPA to regulate CO_2 emissions to the extent mandated by the Clean Air Act. Thus, a national program for CO_2 regulation is expected. The need to anticipate and appropriately account for this national initiative also informs Entergy's comments here.

Comments

Entergy lauds and supports the objectives of the Draft Regulations and its framework. In particular, as Entergy noted in its comments on the RGGI Draft Model Rule, it concurs with the Participating States' recognition of the importance of advancing air quality goals with appropriate sensitivity to public health, environment, energy and related economic considerations. *See, e.g.,* RGGI Memorandum of Understanding ("the [Participating] States each individually have a policy to conserve, improve, and protect their natural resources and environment in order to enhance the health, safety, and welfare of their residents consistent with continued overall economic growth and to maintain a safe and reliable electric power supply system."); Mass. Acts of 1997, Ch. 164, § 1(h) ("reliable electric service is of utmost importance to the safety, health, and welfare of the commonwealth's citizens and economy . . . ."). As cannot be said too often, electricity is an essential service, and its reliable supply is not only an economic imperative, but a public health and safety necessity.

In recognition of the fact that the Draft Regulations are Massachusetts' implementation of the RGGI Model Rule, Entergy hereby incorporates by reference, and attaches as **Exhibit A**, those relevant comments on the RGGI Draft Model Rule and focuses herein on the aspects of the Draft Regulations that are specific to Massachusetts' implementation of the RGGI Model Rule. As the Department has noted, principal among the Massachusetts-specific provisions is the proposal to allocate nearly 100% of the Commonwealth's budget of CO_2 emission allowances to the Massachusetts Auction Account (the "Auction Account") and to further distribute such allowances via auctions administered by the Division. Entergy supports the Department's proposal to dedicate some of the Commonwealth's budget of CO_2 emission allowances to the Greenhouse Gas Credit Exchange Set-Aside Account, and recommends that such allowances be awarded on a 1:1 basis for any Greenhouse Gas Credit generated pursuant to 310 CMR 7.29 and 310 CMR 7.00, Appendix B(7).

I. Suggestions regarding the Design and Operation of Auctions of CO_2 Emission Allowances

Entergy supports a proposal to pursue a responsible auction process that observes the economic truism that an open and unconstrained auction, with clear guidelines for the use of revenues, creates a better functioning market than other options. The Commonwealth's proposal is a sound start to achieving such an auction process. Entergy's comments, below, are designed to provide additional insight, and strategic direction, with respect to the auction process and the use of proceeds. Entergy's proposal for the use of proceeds is particularly innovative, but designed to allow development of a CO_2 program which affects market behavior and the development of emission-free generation.

Briefly, Entergy urges Massachusetts to use an unconstrained, open and verifiable auction process. All fundamental auction details, including those discussed below, should be provided in the final regulations or in the documents governing any multi-state or regional auction in which Massachusetts elects to participate. Entergy recommends that the final auction process selected by the Commonwealth incorporate the following:

- Unconstrained Auctions: The tipping point for ensuring effective development of carbon-responsible technology remains uncertain. As such, auctions must be allowed to operate without artificial constraints that may negatively impact the price of the commodity (particularly those that risk sending improper price signals with respect to the emission of CO_2). For these reasons, Entergy does not support the use of caps, "opt out" or "safety" provisions in the auction process.

- Open Participation: Auctions of CO_2 emission allowances that are open to the general public represent a thoughtful and responsible market-based approach to environmental regulation. Conversely, limiting auction participation to entities requiring allowances simply reflects the allowances formula achieved through less direct means, with the result that proper signals to the market are unlikely to be sent. Entergy therefore suggests that all persons or entities be eligible to participate equally in auctions of CO_2 emission allowances, and also be authorized to hold and transfer such allowances.

  Indeed, the research group enlisted by the New York Energy Research and Development Authority, on behalf of the Participating States, to analyze auction design supported an auction format open to the public in the strongest terms.[4] Their seven fundamental recommendations included the following: "Allowance auctions should be open to any party willing and able to meet financial qualification

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4 Dallas Burtraw *et al.*, "Auction Design for Selling CO_2 Emission Allowances under the Regional Greenhouse Gas Initiative: Phase I Research Report (Draft)," (May 25, 2007) at pg. 28, *available at* http://www.coopercenter.org/econ/sitefiles/documents/pdf/rggi_interim_report.pdf

requirements."[5] As noted above and basic economics dictates, the research group stated that limiting participants in an auction "eliminate[s] most of the advantages of having tradable allowances," effectively undermining the very process itself.[6] Also according to the group, an open auction reduces the potential for collusion and market-power abuses. Because of the significant negative effects of limiting auction participation, Entergy suggests that the proposed categories of bidders in the Draft Regulations be removed.

Further, any requirement that individuals or entities meet pre-qualification standards, including minimum financial requirements, to participate in the auction of allowances should be established and explained in sufficient detail to ensure that participation in the auctions is not inappropriately limited, e.g., so as to distort natural market operations. In particular, not-for-profit environmental organizations and small-scale renewables developers should not be constrained from participating in auctions through needlessly stringent pre-qualification standards. Certainly, standard auction mechanisms to ensure payment, and therefore proper auction function, can and should be brought to bear.

- <u>Confidentiality of Business Transactions</u>: The disclosure requirements applicable to entities purchasing CO_2 emission allowances in an auction must balance the objective of creating a transparent auction process with the confidentiality needs of this business sector. Thus, the clearing price for allowances and other information about the auctions should be publicized without identifying either: (i) the individual or entities that purchase allowances; (ii) the number of allowances purchased by any particular auction participant; or (iii) the price paid for allowances by any particular participant.

  Similarly, such information should be identified by the Department and the Division as information that is protected from public disclosure under the Massachusetts Public Records Law. *See* M.G.L. c. 4, § 7(26)(a) and (g) (exempting from public records data that are either "specifically or by necessary implication exempted from disclosure by statute" and "trade secrets or commercial or financial information voluntarily provided to an agency for use in developing governmental policy and upon a promise of confidentiality [except] information submitted as required by law or as a condition of receiving a governmental contract or other benefit.")

- <u>Broad Geographic Scope of Auctions and Use of Allowances from Auctions</u>: Because CO_2 emission allowances are fungible, (i.e., an allowance from Massachusetts' RGGI budget of CO_2 emission allowances provides the same rights to its holder as an allowance from the RGGI budget of any other Participating State), allowances sold at a Massachusetts auction should be eligible to be bought and used by individuals, entities and facilities in any Participating State. Thus, a New Hampshire facility should be able to buy an allowance in the Massachusetts auction and use it to comply

5 *Id.*

6 *Id.*

with the requirements imposed by New Hampshire pursuant to RGGI. Similarly, Massachusetts' CO_2 emissions allowance auctions should be linked to greenhouse gas programs in other states with mandatory and perhaps voluntary GHG regulations, such as California.

To the extent possible, Massachusetts should collaborate with other Participating States to create multi-state/regional auctions, provided that any such regional auction, or alternative state auction, reflect the features discussed herein and ensure against an economic downside for the Commonwealth. This will help ensure that the affordability, reliability and diversity of the Commonwealth's electric system, and the program developed here, are not compromised or diluted. Likewise, integration with a national program should be considered and accounted for.

- Involve Agencies with Energy Policy Expertise: Entergy commends the Commonwealth's recognition of the direct and inevitable relationship between climate-change regulation, electric system function and affordability. Indeed, there is little doubt that CO_2 emission standards will affect energy prices, and indeed must do so to appropriately reflect the costs of these environmental controls. As such, it is important that the regulators with the requisite expertise – that is, those whose mission is to ensure that electricity consumers within the state are provided with reliable and cost-effective electricity – play a substantial role in the implementation of the Draft Regulations. As such and consistent with its comments on the prior 310 C.M.R. 7.29, Entergy appreciates the Commonwealth's proposal for shared responsibility of this program.

The Division has expertise with respect to energy systems, including energy efficiency initiatives, that the Department understandably does not possess. Entergy supports, therefore, the delegation of authority to the Division, subject to the approval of the Secretary of the Executive Office of Energy and Environmental Affairs, to allocate auction revenues. The proposed joint effort by the Department and the Division is not an unprecedented undertaking in the RGGI context. For instance, the RGGI-implementing legislation passed by Vermont in May 2006 calls for the Vermont Public Service Board and Agency of Natural Resources to work together to establish the necessary cap and trade program for CO_2 emissions. *See* "An Act Relating to Vermont's Participation in the Regional Greenhouse Gas Initiative," *available at* http://www.leg.state.vt.us/doc/legdoc.cfm?URL=/docs/2006/acts/ACT168.HTM. Entergy further recommends that the New England Independent System Operator ("ISO"), which manages the electric system, be included in the advisory group of stakeholders that provides advice to the Division with respect to the best utilization of the funds from the CO_2 allowance auctions.

In particular, Entergy supports the current intention for the Division to manage the auction process in light of the fact that the Division is uniquely positioned to recognize not only the CO_2 reduction contributions of the Draft Regulations, but also their impact on the price of energy for residents and businesses throughout the Commonwealth.

- Quality Control: Any allowance-allocation method, including an auction process, should include appropriate quality control mechanisms. The Division's evaluations of the strength of the Commonwealth's energy system and determinations with respect to the need to amend the auction process, will help to ensure that auctions operate as intended, and do not negatively interfere with the reliability of the Commonwealth's electric supply. (Again, consultation with the New England ISO may also be appropriate in designing, monitoring and evaluating the success of the Commonwealth's CO_2 emission allowance auctions.) The implementation of any change to the auction system should depend on determinations regarding the strength (e.g., reliability, affordability and diversity) of the electrical system, rather than solely the cost of allowances. Similarly, the Department should defer to the Division's expertise in determining when it is necessary and appropriate to modify the method of allocating allowances.

III. Suggestions Regarding the Use of Auction Revenues

Entergy unequivocally supports those elements of the provision in the Draft Regulations, *e.g.,* 225 CMR 13.06(8), supporting uses of auction revenues to achieve "*cost minimization to electricity customers* and the promotion of energy efficiency, reliability, demand response, peak shaving (the reduction of peak energy usage), and other strategic energy goals of the Commonwealth." (Emphasis supplied.) Consistent with this proposed mandate, Entergy suggests that a substantial portion of auction revenues be reserved to defray energy costs for low-income Massachusetts residents. Low-income Americans are expected to face a particular economic burden in bearing the costs of environmental regulation, and Entergy believes that RGGI should ease, not exacerbate, their economic situation. In particular, Entergy suggests that auction revenues be allocated to a special fund available for low-income residents, ideally through application or participation in existing electricity-cost defrayment programs at the federal, state and local level, e.g., Low-Income Home Energy Assistance Program ("LIHEAP"). Integration with existing programs may reduce administrative costs and take advantage of existing networks familiar to needy electricity customers. This approach directly addresses the risk of likely impacts of the Draft Regulation on the poor. Further, appropriate use of auction revenues to encourage energy efficiency could have the auxiliary benefit of improving the short-term management of demand. Entergy recognizes the innovative nature of this proposal, and extends an offer to meet with the Commonwealth to further discuss its details.

Given the connection between reliability, affordability and fuel diversity, Entergy recommends that the Draft Regulations be revised to expressly promote low- and non-CO_2 emitting sources of electric generation as an appropriate and desirable secondary use of auction proceeds.[7] This

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[7] *See e.g.,* ISO New England, 2006 Regional System Plan, (Oct. 26, 2006) at pgs. 3 and 7, *available at* http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf ("To further improve the regional fuel mix, the ISO, with all regional stakeholders, should encourage the addition of economic alternatives to using gas- and oil-fired generation. These alternatives include nuclear energy, renewable generation, such as wind and hydro imports, and new coal technologies.") and ("RSP06 studies show that meeting RGGI's carbon dioxide cap will require stronger regional efforts in conservation and energy efficiency, the addition of low- or zero-emitting baseload generation, or a combination of all measures by 2015. If Massachusetts and Rhode Island were to

recommended revision is consistent with the RGGI Model Rule, which provided that allowances set aside for a Consumer Benefit or Strategic Energy Purpose Account, or similar set-aside account, should be used to encourage and foster the promotion of, among other things, both renewable and non-carbon-emitting energy technologies. The observance of the principle of fuel-neutrality fosters fuel diversity, a tenet of a reliable and affordable electric system.[8] However, Entergy expressly notes that not all carbon-reduction programs are the same, with the result that "paper" reductions that entail short-term benefits should not compete with the long-term benefits of retrofitting existing carbon-emitting facilities and the addition of non-emitting electric-generation. Likewise, Entergy suggests that funds should be used locally wherever possible.

Finally, the Department and the Division should take all necessary steps to ensure that auction proceeds are dedicated solely to the purposes outlined above, and cannot be inappropriately allocated or siphoned elsewhere, e.g., to the Commonwealth's general fund. Of course, decisions regarding the allocation of auction proceeds should be made in an open and transparent manner.

IV. Support for and Suggestions Regarding Offset Provisions

Entergy supports the Draft Regulations' language that: (i) allows any individual or entity to create, hold and/or transfer CO_2 offset allowances, and (ii) provides CO_2 offset allowances to projects that both reduce and avoid CO_2 emissions. This latter provision is an important step towards creating a fuel-neutral program. Although the intent of the Draft Regulations to award offsets for avoided CO_2 emissions is clear, Entergy suggests that, for clarity's sake, any reference in the Draft Regulations to the award of CO_2 offset allowance for "demonstrated reductions in

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join RGGI, this need could advance to as early as 2010."); *see also* ISO New England, New England Electricity Scenario Analysis, (Aug. 2, 2007) at pg. 71, *available at* http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf ("Thus, reducing the region's CO_2 emissions as part of complying with the Regional Greenhouse Gas Initiative would seem to require some combination of adding substantial amounts of low- or zero-emitting resources, having RGGI-affected power generators buy additional CO_2 allowances or use previously banked ones, buying offsets from outside the electricity sector, redispatching the electric system to burn fossil fuels more efficiently (or not at all), retiring some power plants that emit substantial quantities of CO_2 emissions, switching fuels, increasing imports, or using some economic combination of these approaches.")

8 *See e.g.*, ISO New England, New England Electricity Scenario Analysis, (Aug. 2, 2007) at pg. 1, *available at* http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf ("To improve system reliability, system planners have identified the need to diversify the types of fuels used to generate electricity and decrease the region's dependence on natural gas."); *see also* ISO New England, 2006 Regional System Plan, (Oct. 26, 2006) at pgs. 69 and 132, *available at* http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf ("For the near and long terms, the ISO and regional stakeholders, including state regulators and siting councils, must begin planning for the use of alternative resources to diversify the current mix of fuels. . . . Wind power, nuclear, new coal technologies, and additional Canadian imports of electricity must all be considered if New England is to move toward a more diversified fuel-supply portfolio.") and ("The following actions are needed to improve the reliability of the system and reduce exposure to price volatility . . . . improve the region's fuel diversity for the long term, increase renewable generation resources and consider adding new coal and nuclear technologies.")

CO_2" be revised to instead reference the award of CO_2 offset allowances for "demonstrated reductions in or avoidances of CO_2."

Conclusion

Entergy shares and supports Massachusetts' goal of addressing CO_2 emissions in a manner that is consistent with the RGGI Model Rule and that supports a reliable and affordable energy supply for the Commonwealth's citizens. Entergy therefore appreciates the opportunity to submit these comments and welcomes the opportunity to work further with the Commonwealth to develop a meaningful, innovative and successful regulatory program, auction system and trading program to support Massachusetts' and RGGI's progressive CO_2 emission standards. Any questions regarding our comments may be directed to Elise Zoli (at 617-570-1612).

Exhibit A

Comments of Entergy Corporation on the Regional Greenhouse Gas Initiative's Public Review Model Rule Draft 03/23/06

Introduction

Entergy Corporation and its direct and indirect subsidiaries (collectively, "Entergy") respectfully submit these comments in response to the Draft Model Rule for the Regional Greenhouse Gas Initiative ("RGGI") that was provided for public comment on March 23, 2006 (the "Draft Rule").

By way of background, Entergy owns numerous fossil-fuel facilities, generating over 30,000 megawatts ("MW") of electricity worldwide, and is the second largest owner and operator of nuclear power plants in the United States. With respect to its nuclear operations, Entergy companies own or operate eleven (11) nuclear units, five (5) of which are located in the northeastern United States. Within the RGGI Region (i.e., the states currently committed to participating in RGGI - Connecticut, Delaware, Maine, Maryland, New Hampshire, New Jersey, New York and Vermont – collectively, the "Participating States"), Entergy owns and operates: (1) Vermont Yankee Station – a 535 MW electric generation facility in Vermont that produces approximately 72% of the electricity produced within the state, and (2) Indian Point, Units 2 and 3, and the James A. Fitzpatrick Station – three facilities located in New York with a cumulative capacity of 2,775 MW that collectively produce approximately 16% of the state's power. (Because Massachusetts played a role in the RGGI-development process, it is also noteworthy that Entergy owns and operates the 670 MW Pilgrim Nuclear Power Station in Massachusetts, which, according to the New England Energy Alliance, avoids approximately 1.6 million tons of carbon dioxide ("CO_2") a year – the amount that would be generated if the facility's output were to be replaced with the output of existing fossil-fuel generation facilities.) In addition to their critical contribution to the power supply, Entergy's nuclear facilities also provide an important and largely unrecognized environmental benefit to the RGGI Region. Since the 1970s, Entergy's and others' nuclear stations have demonstrated their value, not only by producing reliable base-load electricity, but by generating that electricity without emitting CO_2, sulfur dioxide ("SO_2"), nitrous oxides ("NOx") or mercury. Entergy brings to nuclear operations an unparalleled expertise and a commitment to safe, secure and cost-effective energy production with significant environmental and public-health benefits.

As one of the largest producers of electric power in the United States, Entergy recognizes its leadership role in delivering power while protecting the environment and public health. In particular, Entergy is committed to improving air quality and helping to successfully redress climate change. For example, in 2001, Entergy made a public corporate commitment to stabilize company CO_2 emissions at 2000 levels through 2005. Cumulatively, through 2005, Entergy reduced emissions 23%, while increasing electric sales by 21% over the same period. On May 1, 2006, Entergy expanded its commitment to stabilize CO_2 emissions at a level 20% below the 2000 levels for the years 2006 through 2010. Examples of Entergy's climate-related undertakings in 2006 include transactions involving the acquisition of 300,000 metric tons of greenhouse gas ("GHG") emission reductions that Entergy will retire as part of its voluntary emission reduction initiative and participation in Massachusetts' development of a GHG emissions trading program. Furthermore, as you are no doubt aware, Entergy has been an active stakeholder in and vocal supporter of the multi-year development process of RGGI – consistent with Entergy's support for mandatory CO_2 regulations. *See, e.g.,* CERES, "Corporate Governance and Climate Change: Making the Connection," (March 2006) at pg. 87, *available at* http://www.ceres.org/pub/docs/Ceres_corp_gov_and_climate_change_0306.pdf (" Both Entergy's CEO and Chairman have spoken publicly about the dangers of climate change . . . and the need for immediate government action."). In addition to its nuclear-powered fleet and fossil-fuel facilities, Entergy is committed to advancing renewable-power generation, and already includes in its fleet wind-turbine projects (in Iowa and Texas) and several hydro-electric projects (in Arkansas and Texas).

Consistent with its commitment to climate-change initiatives, Entergy understands the complexities of creating a successful cap-and-trade program for CO_2 emissions – one that advances important environmental objectives without compromising an affordable, reliable and diverse supply of electricity in the RGGI Region.

Entergy commends the Participating States for recognizing the interactions between environmental regulations and energy policies and creating an Inter-State RGGI Staff Working Group (the "Working Group") that includes representatives from the various public service commissions and their electric-system expertise. Entergy appreciates both the Participating States' initiative in the arena of CO_2 regulations, and the time and effort, particularly of the Working Group, devoted to creating the Draft Rule. Entergy also appreciates the opportunity to submit these comments on the Draft Rule.

Comments

Entergy generally supports the objectives of the Draft Rule. In particular, Entergy concurs with the Participating States' recognition of the importance of advancing air quality goals with appropriate sensitivity to public health, environmental, energy and related economic considerations. *See, e.g.,* RGGI Memorandum of Understanding ("MOU") ("the [Participating] States each individually have a policy to conserve, improve, and protect their natural resources and environment in order to enhance the health, safety, and welfare of their residents consistent with continued overall economic growth and to maintain a safe and reliable electric power supply system."). New, license extended and uprated nuclear facilities ("Nuclear Plants") may uniquely contribute to meeting these goals of a reliable and affordable electric-system while improving air quality.[1]

Nuclear plants provide a recognized and important base-load source of power that cannot be replaced with other non-emitting generating sources, such as wind or solar projects, the operation

1 *See e.g.,* Electric Power Research Institute, "2006 Portfolio: 41.010 New Nuclear Plant Deployment," *available at* http://www.epriweb.com/public/2006_P041-010.pdf ("[T]he importance of fuel diversity to better absorb shocks such as fuel supply restrictions, the need to reduce dependence on foreign oil, the need to better address pollution and global warming concerns are all reasons to provide nuclear generation in the future."); *see also* Nuclear Energy Institute, "Nuclear Facts," *available at* http://www.nei.org/index.asp?catnum=1&catid=1 ("Nuclear power plants provide low-cost, predictable power at stable prices and are essential in maintaining the reliability of the U.S. electric power system.").

of which cannot be assured in all conditions[2] Nuclear facilities also provide a recognized and important market-stabilizing function through the use of long-term power-purchase agreements and their market-bidding behavior. Indeed, energy-market experts, such as ISO New England, the New York ISO and PJM Interconnection, have indicated that maintaining a sufficiently diverse source of electrical generation, including nuclear power, is necessary to ensure a reliable and affordable supply of electricity, particularly under RGGI.[3] Because of the unique and important role that Nuclear Plants play in achieving a reliable and affordable electric system that minimizes negative air quality impacts, Entergy can offer comments on the Draft Rule from a relatively unique perspective – as the second largest owner/operator of nuclear facilities in the country, and as a company that supports mandatory CO_2 regulations that would apply to its own fossil-fuel facilities.

The Draft Rule is a substantial step forward, and Entergy once again commends the Participating States and Working Group for their groundbreaking efforts. However, as currently drafted, the Draft Rule inadvertently risks creating a program in which developers are disincentivized from undertaking CO_2 emission reduction projects, resulting in a limited and overpriced market for CO_2 offset allowances. Such a result would contradict RGGI's objective of maximizing CO_2 emission reductions with minimal electric-system impacts. Entergy's comments, if accepted, resolve these risks to market function and, therefore, RGGI's goals. This is all the more important here, since RGGI, if successful, undoubtedly will be a model for future national CO_2 regulations, and, if unsuccessful, may delay implementation of important air-quality initiatives. In short, there is simply no avoiding that the future success of air-quality measures depends, in no small measure, on how effectively RGGI functions.

I Support for and Suggestions Regarding Specific Tenets of the Draft Rule

Entergy has historically advocated for the following principles and supports their inclusion in the Draft Rule as essential components in creating a program that effectively balances important environmental and public health goals with essential energy policy objectives.

- Mandatory market-based (i.e., competitive) regulation of CO_2 emissions, on either a national or regional scale. Allowing any person, whether or not regulated by RGGI, to hold, create and transfer CO_2 allowances and offset allowances fosters a free-market. Similarly, allowing Participating States to conduct auctions of CO_2

2 *See e.g.*, National Rural Electric Cooperative Association, "White Paper on Wind Power," (April 2003), *available at* http://www.nreca.org/Documents/PublicPolicy/Windwhitepaper.pdf ("Power from wind and photovoltaic systems is intermittent and cannot be scheduled or dispatched reliably to meet system requirements.")

3 *See e.g.*, Mark Babula, ISO New England, "RGGI Design, Markets and Reliability – Issues Relating to Systems Operations," (Nov. 30, 2004), *available at* http://www.rggi.org/docs/babula_pres_11_30_04.ppt ("Consider fuel diversity an essential feature of electric system planning," and "reliability is paramount."); ISO New England, "Regional System Plan 2005," (Oct. 20, 2005), *available at* http://www.iso-ne.com/trans/rsp/2005/05rsp.pdf ("About two-thirds of New England generation relies on gas or oil as its primary fuel. A more diverse portfolio is highly desirable since gas and oil are the most expensive fuels, are highly volatile in price, and are increasingly dependent on imported supply.").

allowances with all generators, whether or not regulated by RGGI, will help create a demand, and subsequent financial value for, CO_2 allowances (i.e., CO_2 emission reductions) that will encourage the development of projects eligible for CO_2 offset allowances, thereby furthering RGGI's overarching objective of reducing CO_2 emissions.

- Fuel-neutral, air quality regulations. Entergy supports the flexibility awarded to Participating States with respect to allocating their CO_2 allowances and the inclusion of non-carbon emitting energy technologies as an activity to be encouraged and fostered via the sale or distribution of allowances from consumer benefit/strategic energy purpose accounts. The Draft Rule should be amended to require that any method selected for distributing CO_2 allowances to new facilities, including Nuclear Plants, treat such sources in a fuel-neutral manner.

- Involving Electric-System Experts. Involvement of regulatory agencies with expertise in energy issues should be a premium. RGGI's success depends on a resounding public perception that energy services are not compromised or made substantially less affordable. Energy regulators will have insight into the delicate balance that must be achieved, and how it is best achieved.

- RGGI's Value as a Precedent. As illustrated by its comments submitted to the United States Senate Committee on Energy and Natural Resources in connection with its April 4, 2006 Climate Conference, Entergy generally supports the use of cap-and-trade programs that recognize the contribution of all electric generators, regardless of their fuel source, as a means of achieving environmental objectives. For the sake of uniformity and predictability – factors which help businesses forecast the price of their goods and alleviate undesirable fluctuations in electricity pricing – a national standard for CO_2 emissions is preferable. RGGI is the most visible step forward to a national standard, and its relative success will in large part determine the future of CO_2 regulation. For this reason, decisions regarding the Draft Rule must be carefully considered relative to their potential national impacts.

Each of the above is addressed in greater detail below:

A. Mandatory Market-Based Regulation of CO_2 Emissions

For market-based approaches to environmental regulations to succeed, the market must be allowed to operate without artificial constraints that negatively impact the demand, supply or price of a commodity. Open access to markets corresponds to true demand, in this case, the demand for CO_2 emission reductions, which is the purpose of RGGI. Entergy therefore supports the provisions in the Draft Rule that permit any person to either hold and transfer CO_2 allowances or to create and transfer CO_2 offset allowances. Including entities beyond those units directly governed by the Draft Rule, i.e., "Non-Affected Facilities," as parties qualified to create and sell CO_2 allowances and CO_2 offset allowances is an essential component in fostering a sufficient and sustainable allowance trading market that will achieve the environmental goals of the RGGI standards, while simultaneously protecting the reliability and affordability of the

RGGI Region's electricity supply. Broad access to the market ensures that CO_2 allowances and offset allowances have adequate value to encourage novel or innovative projects, including renewables or new nuclear facilities, that further the nation's twin air-quality and electric-supply goals. Entergy is aware that there is an incorrect assumption that new nuclear construction does not need economic encouragement; however, thirty years of no nuclear construction – the last new nuclear facility construction was approved in 1979 – suggests that appropriate economic encouragement is warranted. Similarly, Entergy believes that any auction of CO_2 allowances should be open to all electric generators, regardless of their fuel source or regulated status under RGGI. If the natural demand for CO_2 allowances (i.e., CO_2 emission reductions) is fettered by restrictions on issues such as auction participants, the price of CO_2 allowances could be artificially dampened, thereby creating a disincentive for the development of additional projects eligible for CO_2 offset allowances – such a result would impede the driving objective of RGGI to reduce CO_2 emissions.

B. Fuel-Neutral Air Quality Regulations

Entergy also supports the flexibility awarded in the Draft Rule to Participating States in determining how their CO_2 allowances shall be distributed – in particular, the lack of restriction on the methods that Participating States can use to distribute their assigned CO_2 allowances (other than the requirement to set-aside twenty-five percent (25%) of the allocation for consumer benefit or strategic energy purposes). This design allows Participating States to allocate CO_2 allowances to all generating facilities, regardless of CO_2 emissions, either immediately or with respect to new generation capacity. Distributing CO_2 allowances on the basis of a facility's contribution to the electric system (i.e., Megawatt-hour output), rather than CO_2 emissions, is a useful means of encouraging the use and development of electricity sources with reduced air-quality impacts, rather than simply dividing the vast majority of the pie among existing emission sources. Under this approach, a wind farm or new nuclear facility would receive CO_2 allowances in the same manner and to the same degree as a new coal-fired plant, thereby recognizing the level of CO_2 emissions avoided. This system will provide incentives for lower or non-emitting sources to enter or remain in the market, the need for which is again evidenced by the fact that there have been no new nuclear facilities built in the United Sates since the late 1970s. This system also ensures fuel diversity, one of the tenets of a reliable and affordable electric system. Similarly, Entergy also supports the Draft Rule's promotion of non-carbon emitting energy technologies as an activity that should be encouraged and fostered via the sale or distribution of allowances from the consumer benefit/strategic energy purpose account.

In short, Entergy recommends that the Draft Rule include a provision requiring Participating States to distribute CO_2 allowances to *all* new sources of generating capacity regardless of their CO_2 emissions, including Non-Affected Facilities, such as new nuclear facilities or those undergoing uprates or license extensions, based on the megawatt-hour output of such sources. (Entergy is not suggesting that the Draft Rule should require Participating States to utilize a particular method to award or distribute allowances to new generating capacity, rather simply that any chosen mechanism should be applied in a fuel-neutral manner. It is important, however, to ensure that RGGI does not create a burden on market entry for new facilities.) By proceeding with an eye to promoting a future that simultaneously incorporates air-quality and fuel diversity considerations, RGGI will best achieve its goals.

C *Involving Electric System Experts*

Entergy commends the Participating States' recognition of the potential for interaction between the proposed RGGI environmental regulations and energy issues. In light of what appears to be the emerging recognition that air-quality regulations are inextricably linked to electric-system function and market pricing, it is important that the regulators with the requisite expertise – that is, those whose mission is to ensure that electricity consumers within the state are provided with reliable and cost-effective electricity – adequately participate in the design and implementation of environmental regulations. The RGGI process has acknowledged and addressed this important dynamic by establishing a Working Group with representatives from both environmental and energy-oriented public bodies. Entergy suggests that the Draft Rule incorporate language encouraging Participating States to maintain a similar level of cooperation between environmental and energy agencies as they develop and implement legislation and/or regulations to implement RGGI. The viability of such an approach at the state level is illustrated by the RGGI-implementing legislation recently passed in Vermont, which calls for the State Public Service Board to work with the State Agency of Natural Resources to establish the necessary cap and trade program for CO_2 emissions. *See* "An Act Relating to Vermont's Participation in the Regional Greenhouse Gas Initiative," *available at* http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT123.HTM. Moreover, it is the Public Service Board's responsibility to establish a process to allocate Vermont's budget of CO_2 allowances and the proceeds from the sale of such credits.

II Recommendations regarding Offset Provisions of the Draft Rule

Entergy appreciates the Working Group's specific solicitation of comments on the Draft Rule's offset provisions. This section of the Draft Rule is a novel aspect of the RGGI program that, in laying the groundwork for future iterations of offset schemes, goes beyond its technical value. As discussed above, a diverse source of CO_2 offset allowances will help promote the dual goals of RGGI – effectively and continuously reducing CO_2 emissions (including through encouragement of non-emitting sources) and minimizing the impacts of CO_2 emissions standards on the electric system. Generally speaking, Entergy believes that the type of system best able to meet these objectives is one in which any project that meets specified standards is eligible to generate CO_2 offset allowances. Recognizing, however, that the Participating States have opted, for the time being, to approve only limited projects as eligible for CO_2 offset allowances, Entergy offers the following suggestions for strengthening the mechanism outlined in the Draft Rule.

Briefly:

- Include a protocol or standards allowing expansion of the projects eligible to receive CO_2 offset allowances.

- Continue to make CO_2 offset allowances available to (i) any person sponsoring an eligible project and (ii) all projects that either *reduce or avoid* atmospheric loading of CO_2 or CO_2 equivalent. To ensure that this approach is properly implemented, revise all references to the award of CO_2 offset allowances for "demonstrated reductions in CO_2" to "demonstrated reductions in or avoidance of CO_2."

- Allow CO_2 emission credits issued pursuant to programs within the United States, but outside the RGGI Region, to receive a RGGI CO_2 offset allowance if retired. Similarly, projects that retire CO_2 credits or allowances received under other mandatory or voluntary greenhouse gas programs should be eligible to receive RGGI CO_2 offset allowances.

- Avoid "regulatory plus" additionality requirements and remove those, e.g., limits on receiving funding or credits from systems benefit funds or renewable portfolio standards, that may deter development of new technologies or projects with multi-pollutant benefits.

- Avoid "financial additionality" factors requiring applicants to demonstrate that the sale of CO_2 offset allowances certified in accordance with RGGI is anything other than a relevant financial consideration prompting the implementation of a project. Removing financial additionality provisions reduces uncertainty as to which projects satisfy the Draft Rule eligibility requirements, thereby reducing the risk that investors will decline to participate in the development of new technologies in the field of CO_2 reductions. It also reflects the market reality that it is unlikely for a single factor to drive project development.

- Avoid "environmental additionality" factors that preclude projects that comply with all applicable environmental laws and regulations. Projects that have obtained all required environmental permits should be eligible for CO_2 offset allowances. Without such a guarantee, an environmental additionality requirement would risk creating a system in which offset project approvals are arbitrary and capricious.

The above comments are further detailed below:

A Protocols for Expanding the Projects Eligible for CO_2 Offset Allowances

The Draft Rule should be amended to specify a process by which the Participating States can either (i) amend the offsets provisions by replacing the limited categories of projects eligible for CO_2 offset allowances with general standards governing eligibility, or (ii) increase the list of pre-approved projects eligible for CO_2 offset allowances. Such a provision will facilitate the recognition and encouragement of the air quality benefits from existing and new non- CO_2 generating sources and the ability of RGGI to evolve in a manner that recognizes and accounts for the contribution to air quality from the development of new technologies and entrepreneurial projects that can contribute to the reduction of CO_2 emissions.

B Availability of CO_2 Offset Allowances to Projects that Reduce or Avoid CO_2 Emissions

Entergy supports the Draft Rule's provision of CO_2 offset allowances to projects that both reduce and avoid CO_2 emissions as an important step towards creating a fuel-neutral program that recognizes and encourages the important and equal contribution of renewable and non- CO_2 emitting technologies to air quality. Entergy suggests that, for clarity's sake, new language added to the Draft Rule regarding the future expansion of the types of projects eligible for CO_2 offsets, as discussed above, also specify that eligibility will be extended to CO_2 emission offsets projects that either "reduce or avoid" atmospheric loading of CO_2 or CO_2 equivalent. Although the intent of the e Draft Rule to award offsets for avoided CO_2 emissions is clear, Entergy recommends revising any reference to the award of CO_2 offset allowances for "demonstrated reductions in CO_2", such as in Section XX-10.7 of the Draft Rule, to the award of CO_2 offset allowances for "demonstrated reductions in or avoidance of CO_2."

C Availability of CO_2 Offset Allowances to Projects that Retire CO_2 Credits from other Programs within the United States

Entergy believes that offset allowances should be awarded to the retirement of any CO_2 emission credit generated outside of the RGGI Region. In other words, CO_2 credits awarded pursuant to mandatory or voluntary programs anywhere in the United States, other than the RGGI Region, should receive RGGI CO_2 offset allowances, if retired. Furthermore, projects should not be excluded from receiving CO_2 offset allowances merely because they are awarded credits or allowances under another mandatory or voluntary greenhouse gas program or market. Instead, such projects should be eligible to receive RGGI CO_2 offset allowances if they document the retirement of such non-RGGI CO_2 credits or allowances without receiving any benefits under RGGI for such retirements, i.e., RGGI CO_2 offset allowances for the retirement of emission credits. The Draft Rule should not supplant the right of a project developer or investor to choose the program under which a project will receive CO_2 offset allowances or credits. Moreover, this approach could help maintain affordable pricing for CO_2 offset allowances within the RGGI Region. For instance, if the cost of a RGGI CO_2 offset allowance is high, proponents of CO_2 emission reducing projects may choose to retire lower-value CO_2 credits from other programs and instead participate in RGGI, thereby increasing the supply of, and helping to lower the price of, RGGI CO_2 offset allowances.

D "Regulatory Plus" Additionality

Entergy appreciates that the "regulatory plus" additionality requirements included in Section XX-10.3(d)(2) of the Draft Rule do not preclude projects from receiving CO_2 offset allowances because of their participation in, or receipt of funds from, programs not explicitly listed in the Draft Rule, such as those within the ambit of the Energy Policy Act of 2005. However, the sources of funding and incentives that the Draft Rule provides make a project ineligible to receive RGGI CO_2 offset allowances are sufficiently broad that their inclusion could result in very few projects electing to participate in the RGGI offset allowance scheme, thus jeopardizing a robust CO_2 offset market and RGGI's ability to achieve its environmental objectives without causing unacceptable electric-system impacts. For instance, the Draft Rule requires project sponsors to choose between the value of RGGI CO_2 offset allowances and the credits that could be used for compliance with renewable portfolio standards; however, it is not clear that any financial analysis has been undertaken to determine when, if at all, the value of new RGGI CO_2 offset allowances will outweigh the value of established renewable portfolio standard credits.

Moreover, the current "regulatory plus" provisions could deter the development and deployment of CO_2-emission reducing technologies that are on the cusp of economic viability or that provide multi-pollutant benefits. As written, the Draft Rule encourages developers to create projects, to the extent possible, that either only reduce or avoid CO_2 emissions or that reduce or avoid all emissions other than CO_2. Entergy therefore recommends that the "regulatory plus" additionality provisions in the Draft Rule be removed in their entirety. The impact of such deterrents on the development of CO_2 offset projects must be considered in the full context of the Draft Rule, which already includes provisions that discourage investment in projects eligible for CO_2 offset allowances. For instance, the fact that (i) CO_2 allowances do not constitute a property right, (presumably the same is true for CO_2 offset allowances although the Draft Rule is not clear on this point), and (ii) that certified projects can lose their CO_2 offset allowances based on future regulatory changes, may deter developers from undertaking or investors from financing projects eligible for CO_2 offset allowances because of the risk that any allowances eventually awarded could be taken back by a Participating State with no compensation.

E "Financial" and "Environmental" Additionality

No further financial additionality requirements should be added to the Draft Rule because such provisions will not only deter investment in CO_2-emission reducing technologies, but will also be difficult to implement, requiring regulators to "get inside" the minds of project proponents – an approach that is fraught with the risk of subjective and unpredictable implementation. More financial additionality requirements are not necessary to maintain an appropriate balance between RGGI's environmental objectives and the realm of energy policy, which is the appropriate forum for debating the role that financial considerations should play in shaping the composition of the RGGI Region's electricity supply. Moreover, adding financial factors to an additionality test could preclude the development of projects most likely to obtain financing, thus creating an obstacle to projects that could help reduce the level of CO_2 emissions – an outcome that would be contrary to the purpose of RGGI's CO_2 emission standards. Investors must be willing to facilitate and finance the development of CO_2 offset projects if RGGI is to succeed, and a level and predictable playing field is necessary to attract the requisite participation from the financial sector. Similarly, any inclusion of environmental factors in additionality requirements should not be capable of being used to prevent the allocation of CO_2 offset allowances to projects that have obtained all required environmental permits.

Conclusion

Entergy shares and supports RGGI's goal of addressing CO_2 emissions in a manner that supports a reliable and affordable energy supply for the RGGI Region's citizens. Entergy therefore appreciates the opportunity to submit these comments and welcomes the opportunity to work further with the Working Group and Participating States to help create a Model Rule and to implement legislation and regulations that will achieve a meaningful, innovative and successful regulatory program and allowance trading program to support RGGI's progressive CO_2 emission standards. Any questions regarding our comments may be directed to Elise Zoli at 617-570-1612.

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