RGGI Regional Greenhouse Gas Initiative
An Initiative of the Northeast & Mid-Atlantic States of the U.S.

Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms

Initial Report of the RGGI Emissions Leakage Multi-State Staff Working Group to the RGGI Agency Heads

March 14, 2007

Acknowledgements

This Report benefited from significant input from the RGGI Emissions Leakage Multi-State Staff Working Group. However, the views, conclusions, findings and opinions expressed in this report are those of the authors (Staff) and do not necessarily reflect the views of the RGGI Agency Heads or their respective states.

The principal authors of this report are **David Farnsworth**, Vermont Public Service Board, **Christina Palmero**, New York State Department of Public Service, and **Christopher Sherry**, New Jersey Department of Environmental Protection.

The following individuals provided insightful comments on drafts of this report: Clifton Below, Commissioner, New Hampshire Public Utilities Commission; Chris Haun, New Jersey Board of Public Utilities; Steve Keller and Mark Reeder, New York State Department of Public Service; Cindy Jacobs, Connecticut Department of Public Utility Control; and Rick Weston, Regulatory Assistance Project.

The authors would also like to express their appreciation to those individuals that participated in the workshop: Electric *Imports and Emission Leakage,* sponsored by and held at the Vermont Law School on June 15-16, 2006, and whose insightful presentations and comments laid the foundation for this report.

RGGI Emissions Leakage Multi-State Staff Working Group

<u>Connecticut</u>
Chris James, CT Department of Environmental Protection
Cindy Jacobs, CT Department of Public Utility Control

<u>Delaware</u>
Phil Cherry, DE Department of Natural Resources and Environmental Control
Bob Howatt, DE Public Service Commission

<u>Maine</u>
James Brooks, ME Department of Environmental Protection
Faith Huntington, ME Public Utilities Commission

<u>Maryland</u>
Gene Higa, MD Department of the Environment

<u>New Hampshire</u>
Joe Fontaine, NH Department of Environmental Services
Maureen Reno, NH Public Utilities Commission

<u>New Jersey</u>
Christopher Sherry (co-chair), NJ Department of Environmental Protection
Michael Winka, NJ Board of Public Utilities

<u>New York</u>
Franz Litz, NY Department of Environmental Conservation
Tina Palmero (co-chair), NY Public Service Commission

<u>Vermont</u>
Dick Valentinetti, VT Department of Environmental Conservation
David Farnsworth (co-chair), VT Public Service Board

Table of Contents

Executive Summary

"Emissions leakage" is the concept that there could be a shift of electricity generation from capped sources subject to RGGI to higher-emitting sources not subject to RGGI. The implementation of a carbon cap on power plants is expected to increase the cost of electricity generation in the RGGI region. In a competitive power market, this may have the effect of shifting generation in the larger region to uncontrolled, and presumably cheaper, fossil fuel-fired generation not subject to a carbon cap.[i] This shift in generation and associated emissions from capped sources to non-capped sources is described as "emissions leakage". Because RGGI is being implemented in a competitive generation market, the addition of a carbon compliance cost that applies to only a subset of electric generators in the market could lead to a shift in the dispatch of electric generators and changes in flows of energy on the transmission system in response to this carbon price signal. The concept of emissions leakage is, therefore, specific to a scenario where a larger national program does not exist and a regional program being implemented does not fully cover the respective regional wholesale electricity market(s).

Implicit in this concept is the notion of causality; specifically that a cost increase due to a carbon cap could drive geographic changes in the operation of the electric power system. This is distinct from a shift in the geographic distribution of electric generation resulting from other market variables and the dynamic nature of the electric power market.[ii]

Some stakeholders contend that emissions leakage will undermine the environmental benefits of the RGGI program and place generation assets subject to RGGI at a competitive disadvantage, particularly in the PJM system. The New England states and New York are located within control areas that will be fully covered under RGGI. New Jersey, Maryland, and Delaware are located within the PJM control areas, which also includes Pennsylvania, Virginia, West Virginia, and portions of Ohio, Indiana, and Illinois. The non-RGGI states in PJM have significant coal-fired generation capacity. While leakage could impact the RGGI program as a whole, the discussion of leakage has predominantly focused on market dynamics within PJM, as only a portion of generators in this market would be subject to a RGGI carbon constraint.

In the RGGI Memorandum of Understanding (MOU), the RGGI agency heads recognized the potential for emissions leakage to undermine the goals of a RGGI cap-and-trade program. In acknowledging this possibility, the agency heads directed Staff to study this phenomenon, provide recommendations to

[i] This potential shift in generation could be to uncontrolled generation units both inside and outside the RGGI region.

[ii] Some have advocated for a broader definition of emissions leakage. For further discussion, see footnote #5, pp. 3-4.

monitor it, and analyze policy responses that would be capable of addressing emissions leakage if necessary. With this report, Staff has taken preliminary steps to address each of these tasks.

Part I – The Leakage Debate

There is an active debate as to the magnitude of the potential threat of emissions leakage and the manner in which emissions leakage may occur. On one hand, some argue market dynamics and the practices of market participants could result in a significant amount of emissions leakage. On the other hand, others contend there are mitigating market dynamics and other factors suggesting that, under a modest carbon cap such as RGGI, emissions leakage may not be significant and that concerns for the integrity of the program may be over-stated. The report addresses these market dynamics and related factors in detail.

The report also summarizes emissions leakage projections of energy modeling conducted for the RGGI Staff Working Group and the limitations of the modeling results. The modeling indicates modest emissions leakage, although the components of this projected emission leakage (*i.e.*, shift in location of plant-builds) highlight the limitations of modeling in making refined estimates of emissions leakage.

Currently, there is insufficient information to make refined estimates as to the potential amount of emissions leakage that may occur over the course of the program. Potential emissions leakage is also sensitive to political developments. Given current political momentum toward a national program, Staff views the potential for emissions leakage primarily as a near- to mid-term concern.

Assuming a national program is not implemented in the near future, Staff concludes that key factors to consider will be the relative costs of generation inside and outside the RGGI region, and the interaction of this cost differential with physical transmission capability, the all-in market costs of inter-region power transmission, and the market impacts of transferring significant incremental amounts of power into the RGGI region. The dynamic relationship of physical transmission limits and market factors that may alternately drive or mitigate potential emissions leakage will be a focal point in evaluating the potential impact of the RGGI program on emissions leakage. Given the operational characteristics of the electric power system, Staff also acknowledges that the factors affecting emissions leakage are likely to be temporally and geographically specific. The highly dynamic nature of the factors that may drive or mitigate emissions leakage makes projecting the level of potential emissions leakage difficult.

Part II – Proposal for Monitoring Potential Emissions Leakage

Staff concludes that it is essential to be able to track and verify the environmental attributes associated with all the power being generated and used within the RGGI region, as well as the environmental attributes of power generated in adjoining regions. Such monitoring and verification is necessary to quantify the extent of potential emissions leakage and support RGGI's goals of preventing emissions leakage.

Staff proposes a specific methodology for monitoring emissions leakage. It would require the coordination and minor modification of existing generation attribute tracking systems that are currently being used in the region's electricity markets.

RGGI would regulate CO_2 emissions by all fossil fuel-fired electric generation units that are 25 MW or larger (RGGI-affected units) and are located in a state that implements regulations based on the RGGI cap-and-trade program (in aggregate, RGGI region or in-region). In order to track emissions leakage, a tracking system would account for the in-region load that is being met by generation units other than those units subject to the RGGI program, and the environmental attributes related to this generation. If emissions leakage occurs, it can be expected to result from increased dispatch of either (a) in-region, non-RGGI units (*i.e.*, those fossil fuel-fired units smaller than 25 MW), (b) out-of-region fossil fuel-fired generation serving load in the RGGI region (imports), or a combination of the two (both of which are referred to as non-RGGI generation). The tracking of potential emissions leakage, therefore, can be accomplished by aggregating generation and load data for each of the three control areas fully or partially subject to RGGI, and distinguishing between the RGGI-affected units and the rest of the generation used to serve load region-wide.

To build the capacity for tracking potential emissions leakage, Staff recommends pursuing minor modifications to the existing tracking systems that would distinguish RGGI generation units from other units serving load in the RGGI region. These modifications would create certain new certificate identifiers and would also provide for the ability to create new data reports for certain categories of identifiers. By distinguishing between RGGI units and others, and tracking the environmental attributes of net imports into control areas subject to RGGI, it will be possible to ascertain the current level of load being served by generation units not subject to RGGI, and the related environmental attributes of this non-RGGI generation.

An initial estimate of emissions leakage could be established by tracking over time changes to the level of non-RGGI generation serving RGGI-region load, and changes in the associated CO_2 emissions related to this non-RGGI generation. It should be noted that this approach would not address causality, but instead would track emissions relative to an established emissions baseline for non-RGGI generation units that serve load in the RGGI region. Any increase in emissions from this category of generation units could be considered an initial estimate of emissions leakage. Causality, if addressed, would need to be evaluated on a parallel basis through an evaluation of changes in other market and power system variables during the monitoring period.

Recommendations

To support this monitoring proposal, Staff recommends that the RGGI-participating States take the following actions:

- First, explore modifications to the existing generator attribute tracking systems in the region (PJM's GATS, New England ISO's GIS), and the emerging tracking system currently under development by New York in order to, for each individual control area:

    (i) determine how much electricity is being used in a control area or partial control area subject to RGGI (including supply by generation from within and outside of the RGGI region);
    (ii) determine the environmental attributes associated with the generation of electricity both inside a control area or partial control area subject to RGGI and in adjoining control areas;
    (iii) create generation attribute identifiers for “RGGI-affected unit”, “unaffected small fossil fuel-fired RGGI-region unit“, and “RGGI-region unit”;
    (iv) track net imports into NY-ISO, PJM, and ISO-NE from adjoining control areas and account for related environmental attributes;
    (v) Infer net “imports” into the RGGI portion of PJM and account for related environmental attributes; and
    (vi) generate data reports of “RGGI residual mix”, “unaffected small fossil fuel-fired RGGI-region unit emissions mix”, and “RGGI emissions mix”.

- Second, urge PJM and ISO-New England to make, within the next 12 months, the necessary modifications to GATS and GIS, respectively, that will enable the collection of data and regional coordination among attribute tracking systems necessary to monitor regional emissions leakage; and

- Third, urge the New York PSC to coordinate with PJM and ISO-New England in order to include the features that will enable the collection of the necessary data in the tracking system that New York is currently developing, with the goal of being able to begin collecting the RGGI-related data within the next 12 months; and

- Fourth, using the approach outlined in this report, begin monitoring prior to the start of the RGGI program to evaluate CO_2 emissions from non-RGGI generation in order to develop baseline data.

Furthermore, Staff recommends that, when developing monitoring capabilities for RGGI, attention should be paid to incorporating technical capabilities and design elements that would support the implementation of load-based policies to address potential emissions leakage. Staff acknowledges that the technical capabilities and design elements needed for RGGI monitoring could form the basis of a significant portion of the tracking systems needed to implement policies such as an emissions portfolio standard or a load-based emissions cap. Such design work should be considered now, as emissions leakage tracking capabilities are developed, in order to enable a more rapid implementation of load-based policies if they are considered warranted.

Part III – Policy Options

This portion of the report evaluates, from a qualitative standpoint, various policy options to address potential emissions leakage. These policy options were discussed by stakeholders, independent experts, and RGGI Staff Working Group members during the June 2006, Imports and Leakage Workshop at Vermont Law School. The report considers the degree to which the options meet certain criteria set out in the RGGI MOU, including the effectiveness of each policy in addressing emissions leakage, and the impact of mitigation policies on electric system reliability. Each policy option is also evaluated with respect to implementation challenges that it may present.

Staff has organized the possible policy responses into the following three categories: (1) policies that indirectly address carbon emissions by reducing electricity demand; (2) policies that address, but do not cap, carbon emissions; and (3) policies that cap carbon emissions. A characteristic shared by all of these policies is that they address the end-use of electricity and the emissions that indirectly result from end-use.

Category 1 – Policies that Reduce Electricity Demand

The first category of policies includes mechanisms that would reduce electricity demand. This category of policies is considered an indirect emissions leakage mechanism that constitutes a no-regrets approach, *i.e.*, one that would also provide significant electric system reliability and economic benefits to the RGGI region. These policies include:

- maximization of a consumer benefit/strategic energy purpose allocation, with a focus on end-use energy efficiency;
- implementation of an energy efficiency portfolio standard;
- improved appliance and equipment efficiency standards;

- improved building codes and standards; and
- reductions in barriers to combined heat and power (CHP) applications, and market incentives for CHP.

The use of appliance efficiency standards, building codes and standards, and efforts to reduce market barriers to the deployment of combined heat and power applications are not new. Many RGGI states are currently implementing various types of efficiency programs or standards, and most states recognize that government intervention is necessary to maximize market penetration of cost-effective energy efficiency technologies and practices. It is necessary to adopt such codes and standards in order to overcome market failures that restrict the use of more efficient products and practices. Some of these barriers include limited consumer knowledge, split incentives (*e.g.*, where one party, such as a landlord, purchases the product, while another, a tenant, pays the electricity bills), panic purchases (*e.g.*, where failed units are hurriedly replaced without regard for their energy efficiency), and the sometimes greater initial costs of higher-efficiency products. There are also significant barriers to the deployment of CHP. They include potential resistance by public utilities to opening their systems to outside generation, expensive transmission feasibility studies, potentially high exit fees, and high rates for supplemental and standby power.

Under an Energy Efficiency Portfolio Standard (EEPS), a state utility commission or other regulatory body would specify an energy savings target (or targets) that load-serving entities (LSEs) must meet, on an annual or cumulative basis. The requirement could be set as a percentage of load growth or base year sales, or as a fixed number of units of energy savings. The requirement could also address peak electricity demand. States have found that establishing an explicit, mandatory target, based on sound analysis of technical and economic potential, can help overcome market barriers, regulatory disincentives, or insufficient information about the benefits of energy efficiency that hinder full investment in cost-effective energy efficiency. The adoption of an EEPS would also allow for the achievement of economies of scale, because the entity-wide EEPS requirement encourages energy providers to aggregate savings across multiple end-uses and sectors to meet the overall energy savings goal in the most cost-effective manner.

Each of these policies is designed to reduce electricity demand, and therefore, can be expected to help indirectly reduce emissions leakage. To the degree that electricity demand is reduced, the demand placed on existing generation resources is reduced, and the need to develop new generation capacity is avoided. This reduction in demand for generation supply results in avoided emissions, which, in turn, reduces the demand for CO_2 allowances. This would also be expected to reduce CO_2 allowance price, which would reduce the generation cost differential between RGGI-affected generation units relative to generation units that are not subject to a carbon constraint.

However, while the impact of a reduction in electricity demand has been demonstrated to reduce wholesale and retail energy prices, the relationship is indirect. Determining the amount of energy efficiency resource that would be required to adequately mitigate potential emissions leakage, given an assumed CO_2 allowance price and projected generation cost differential between RGGI-affected and non-affected generation, would depend on future projections arrived at through modeling. Staff notes that modeling conducted for the RGGI Staff Working Group broke new ground in integrating demand-side energy efficiency resources into supply-side electricity sector modeling, and could be used as a starting point for such an analysis.

Staff also notes that energy efficiency policies would have only a limited impact on reducing the carbon intensity of the generation portfolio used to serve load. Energy efficiency policies that reduce the CO_2 allowance price to zero (and, by extension, remove the generation cost differential that could drive emissions leakage) would fail to achieve some of the goals and benefits of a generator-focused cap-and-trade program, which is to modify the dispatch and carbon intensity of the existing portfolio of generation units and incorporate emissions performance into the evaluation of future generation resources. However, energy efficiency policies, to the extent that they result in the deployment of significant energy efficiency resources, would facilitate a lowering of the emissions cap over time.

Category 2 – Carbon Adder and Emissions Rate Mechanisms

The second category of policies more directly addresses carbon emissions, but does not cap these emissions. These policies are the carbon procurement adder, carbon procurement emissions rate, and emissions portfolio standard.

Carbon Procurement Adder

A carbon procurement adder is an analytical tool that requires an LSE planning its resource acquisitions to incorporate a “shadow price” for carbon emissions into its financial analysis of different investment options. The major benefit of developing and implementing a carbon procurement adder is that it internalizes future carbon regulatory risk, and therefore provides utilities with a mechanism with which to evaluate resource supply options while addressing potential future carbon constraints. The mechanism is also relatively easy to administer, depending upon how LSEs are required to procure generation supply. Such a mechanism was recently implemented by the California Public Utilities Commission as a portfolio management requirement.

The carbon procurement adder mechanism is a planning tool designed for LSEs operating in a traditionally regulated – or as in California, re-regulated – environment, and is best suited to the evaluation of plant-specific power purchase agreements. In restructured states, such as the majority of RGGI participating states, implementation of a carbon procurement adder would likely require significant modifications to how state-designated LSE "providers of last resort" are required to procure electric generation supply. As an example, New Jersey currently requires LSEs to procure generation supply through an auction. Winning bids are typically not in the form of plant-specific bilateral contracts, but involve contractual guarantees over a limited multi-year period to deliver a specified amount of energy and capacity to an LSE. A carbon procurement adder would be a greater challenge to implement in such a context, absent significant modification to the procurement process.

As a leakage mitigation option, it would be possible to implement a carbon procurement adder that is equivalent to the RGGI CO_2 allowance price. This would remove any financial incentive for an LSE to change its procurement practices to evade the wholesale price adder due to RGGI. On its face, this would remove RGGI as a causal factor from any incremental increase in power imports and related out-of-region emissions due to LSE power purchasing practices, at least for bilateral purchases. It would be of limited utility as a planning tool to evaluate the carbon intensity of spot market power purchases, as this is a mix of system power including both low-emitting and high-emitting units, and LSEs are price takers in the spot market. LSE purchases of spot market power would not impact the carbon intensity of this power, although LSEs, when managing their power procurement, would need to account for the carbon intensity of spot-market power when making a decision to purchase from the spot market.

It should be noted that this approach would only indirectly impact the dispatch of generators in the region, since generators would face no direct compliance obligation or related cost adder. Theoretically, it would, therefore, not preclude emissions leakage due to a real-time re-dispatch of the regional power system due to a RGGI cost adder. Theoretically, such a procurement adder also might not impact system dispatch at all if the chosen “economic” resource, inclusive of carbon costs, remained the same as the resource chosen without the procurement adder. The dollar value of the adder would therefore be a key variable that could affect the efficacy of this policy as a leakage mitigation strategy.

Carbon Procurement Emissions Rate

A carbon procurement emissions rate is a limit that is placed on the emission rate of power supplied to an LSE through a long-term power purchase agreement. This policy would require all long-term power purchases to meet a specific lbs. CO_2/MWh emission rate; power could not be supplied through bilateral contracts with suppliers that exceed this emissions rate. California recently enacted a statutory requirement that new long-term power purchase agreements (five years or longer) may only be entered into with generation facilities that meet a CO_2 emissions rate equivalent to that of a natural gas combined cycle plant.

As an emissions leakage mitigation option, the emission rate requirement would apply to all new, long-term contracts with power providers. It could be based on the emission rate for a certain class of technology, as was done in California, or on another measure, such as the average emissions rate achieved by all or some subset of generation units within the RGGI region. Both options would ensure that imported power is treated on an equivalent basis as power generated within the region.

Unlike an emissions portfolio standard, as discussed below, a carbon procurement emissions rate would be tied to the bundled electricity commodity, rather than an unbundled emissions attribute. It would therefore directly impact the dispatch of power plants, and could not be avoided through "attribute shuffling".[iii] One drawback is that this policy would not address power purchases in the spot market. If long-term power purchase agreements were not mandated, this could create a disincentive for entering into long-term power purchase agreements. As a result, implementation of this policy in the RGGI region would require a significant modification to how LSEs are required to procure generation supply.

Emissions Portfolio Standard

An emissions portfolio standard (EPS) is a policy mechanism that would require an LSE to meet an average output-based emissions standard (lbs. CO_2/MWh) for the portfolio of supply resources the LSE uses to provide retail electricity. Because it uses an average output-based standard, this mechanism could be adapted to incorporate demand-side resources (*i.e.*, end-use energy efficiency and demand-side management) along with supply-side resources as compliance measures. For instance, energy efficiency resources procured by an LSE could be credited with an emission rate of zero and considered as part of an LSE's overall supply resource when determining the average emission rate for the total electricity supplied by the LSE. This mechanism is also indifferent to the source of generation. The implementation of an EPS in the RGGI states would cover all power that is used to serve retail demand in the RGGI region.

An EPS would establish a market signal to LSEs, and indirectly, power generators, that lower-emitting generation is a valuable commodity. However, it would not necessarily fully address the cost differential between RGGI affected units and those units not subject to the RGGI program. Addressing the cost differential would depend on the relationship between the $/MWh compliance cost faced by the LSE to meet the emission rate requirement relative to the RGGI $/MWh cost adder to wholesale power purchased from within the RGGI region.

[iii] Attribute shuffling, and strategies to address it, are discussed in detail in this report. A related scenario, "contract shuffling", is also discussed.

As a result, though it would mitigate the market dynamics that could lead to emissions leakage, uncertainty would remain as to the efficacy level of this mechanism. It should also be noted that an EPS would only indirectly impact the dispatch of generators in the region (by providing an incentive for low-emitting generation), since generation units would face no direct compliance obligation and related cost adder due to an EPS. It, therefore, would not directly impact the real-time functioning of the electricity market and would not preclude emissions leakage due to a re-dispatch of the regional power system due to a RGGI cost adder.

One disadvantage is that while the policy would limit carbon intensity by holding an LSE to a lbs. CO_2/MWh standard, the electricity demand within an LSE's service territory could continue to increase, which could allow for an increase in absolute emissions of carbon.[iv]

Another potential problem is the potential for "attribute shuffling". An emissions portfolio standard would likely be implemented using an environmental attribute credit trading system, which separates the generation attributes from the electricity commodity. This could be problematic in an open system that includes both regulated and unregulated regions. If an EPS is not properly designed, such a compliance mechanism could potentially allow an LSE to purchase environmental attributes from low-emitting generation outside of the RGGI region without changing its power procurement practices. In such a scenario, an LSE could comply with the emissions standard requirement without impacting the dispatch of generation, and related emissions, in the region as a whole. The specifics of this possible problem and how it might be addressed are discussed in this report.

Category Three – Capping Emissions Associated with Serving Load

The third policy category, referred to here as a load-based emissions cap, is the most direct method for addressing potential emissions leakage. A load-based emissions cap would place a cap on absolute emissions related to all electricity use within a region.

There are three key features of this policy. One, it would set a baseline for emissions associated with the provision of retail electricity by each LSE, and allocate allowances to LSEs based on the emissions related to each LSE's historical electricity purchases. The cap could be set based on a stabilization of emissions at a historic level, or apply an emissions trajectory. Two, at the end of a compliance period, LSEs would have to submit allowances equivalent to the carbon emissions associated with their power purchases. Three, LSEs would be able to reduce the carbon content of their portfolios by contracting with the providers of relatively low-emitting generation or by reducing load in their service territories through energy efficiency and demand-side management. LSEs that

[iv] The report discusses how this issue could be addressed.

reduce emissions below their baseline allocations would have allowances to sell; LSEs that failed to meet their requirements would need to purchase allowances from other LSEs that have exceeded their emissions reduction requirements.

This policy creates a requirement for an LSE to lower the carbon content of its portfolio, while also establishing an indirect market signal to generators that low-emitting generation is a valuable commodity. The policy also accommodates all market-based compliance approaches available to LSEs. LSEs can purchase low-emitting power on the wholesale market, invest in energy efficiency and other demand-side management resources, or purchase emissions allowances from other LSEs if it is economic to do so.

This approach would be effective in addressing the majority of any potential emissions leakage. Assigning a carbon cap to LSEs eliminates the ability of LSE procurement decisions in response to the RGGI program to contribute to incremental emissions increases from generation not subject to a carbon constraint. If properly designed to avoid attribute shuffling, a load-based cap would prevent an LSE from an "end run" around the generator cap-and-trade program, in an attempt to avoid the price impacts of the carbon constraints placed on in-region generation.

It should be noted, however, that, like an EPS, a load-based emissions cap would only indirectly impact the real-time dispatch of generators in the region (by providing an incentive for low-emitting generation), since generation units would face no direct compliance obligation and related cost adder due to a load-based cap. Because LSEs are price-takers in the wholesale spot market, a load-based cap would not preclude near-term emissions leakage resulting from a real-time re-dispatch of the regional power system due to a RGGI generation cost adder. However, LSEs would be subject to a compliance obligation related to the carbon-intensity of spot-market power. If the carbon intensity were high, this would provide a disincentive for LSE reliance on spot-market power and/or an incentive for more aggressive demand-side measures to avoid the need for spot market purchases. As a result, countervailing market forces would be expected to mitigate such an outcome over the long-term. Since LSEs would have a fixed carbon compliance obligation, any near-term emissions leakage due to a real-time re-dispatch of the power system due to a RGGI cost adder would be counter balanced by additional low-carbon power purchases by the LSE or LSE electricity demand reductions.

Any remaining emissions leakage could result from limitations in the precision of an emissions tracking system for a load-based cap, which would rely in part on emissions proxies for certain categories of power purchases.

While staff views a load-based cap as a viable leakage mitigation mechanism, its implementation comes with significant challenges. Under this proposal, an emissions baseline for each LSE would need to be established.

This would require the establishment of emissions estimates related to historical electricity purchases by each LSE over a multi-year period. Unlike a process for estimating regional emissions leakage, establishing LSE baselines for a load-based cap-and-trade system would require detailed analysis of an LSE's historic bilateral power purchases and spot market purchases, and an estimate of the emissions related to those purchases. This would require the use of both ISO market settlement systems and generator attribute tracking systems to evaluate the contract path of LSE electricity purchases and the emissions related to these purchases. As a result, it would present additional requirements beyond those that would be required to track regional emissions leakage through a generator attribute tracking system.

Part IV – Discussion of Electricity Reliability Issues

Finally, the report discusses the potential impact of leakage mitigation measures on electric system reliability. Staff concludes that all three categories of proposed leakage mitigation policy responses would have no significant effect upon electricity system reliability. All of the policies considered in this report place no direct compliance obligation, and related cost adder, on electric generation units. Policies evaluated would either impact electric demand or place specific carbon requirements on LSEs. These policies would be expected to impact the purchasing decision of LSEs with regard to electric generation supply, but would not directly impact the economics of individual electric generators.

Even policies that place a modest compliance obligation on generation units are not expected to impact system reliability. Ensuring system reliability can be understood as an exception to the least-cost economic dispatch model. Generator costs are included in the bid prices that generators submit to their ISO, and generation units are then dispatched on their relative economic merits: the cheapest units are dispatched first; then more expensive units follow. However, system reliability is ensured by allowing units that are required for reliability purposes to be dispatched out of economic merit order. While these units may be more expensive than units that would be dispatched on a solely economic basis, they are directed to operate to maintain system reliability. In essence, reliability "trumps" economic dispatch given the physical constraints of the transmission system.

Part V – Appendices

Much of the discussion in this report requires more in-depth treatment of related topics. For that reason, the report contains appendices that provide further detailed discussions, including:

Appendix I NE-ISO Generator Information System (GIS) and PJM Generator Attribute Tracking System (GATS) Data and Reports;

Appendix II	Development of New York Generator Attribute Tracking System;
Appendix III	Legal Issues; and
Appendix IV	Status of Building Energy Codes and Equipment Energy Efficiency Standards in the RGGI Region.

I. Introduction

Background

On December 20, 2005, seven Northeastern and Mid-Atlantic states (Signatory States)[1] entered into a Memorandum of Understanding (MOU) to implement the Regional Greenhouse Gas Initiative (RGGI) – a region-wide carbon dioxide (CO_2) cap and trade program targeting the electricity generation sector. The MOU outlines the program in detail, including a provision that recognizes that the program may lead to increased electricity imports and associated emissions leakage. To address this potential, the MOU called for the Signatory States to establish a multi-state emissions leakage working group (Working Group or Staff) consisting of representatives from the energy regulatory and environmental agencies in each Signatory State. The MOU tasks the Working Group with the following:

- Consider potential options to address potential emissions leakage, including the effectiveness of each option; and the potential impacts of each option on: (i) energy prices; (ii) allowance prices; (iii) electric system reliability; and (iv) the economies of signatory states.

- Consult with a panel of experts, stakeholders, and representatives of regional transmission organizations as the Working Group reviews various options to address potential emissions leakage, and issue its findings and conclusions by December 2007.

In addition, the MOU calls for the monitoring of electricity imports into the Signatory States on an ongoing basis commencing from the start of the program, and the reporting of results of the monitoring on an annual basis beginning in 2010.

Work Plan

By April 1, 2006, as required by the MOU, the Working Group was formed and thereafter prepared a work plan that was approved by the Signatory States' respective Energy and Environmental Agency Heads (Agency Heads) in June 2006. The work plan provides the general framework for accomplishing the tasks

[1] The seven original Signatory States include: Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont. Subsequently, both Massachusetts and Rhode Island signed the MOU in January and February of 2007, respectively. The Signatory States are also referred to in this report collectively as the "RGGI region". This report also anticipates the participation of Maryland due to an existing statutory requirement for Maryland to formally join the process by mid-2007.

noted above.[2] A schedule is also included, which provides key milestones for developing a final report for delivery to the Agency Heads by December 2007.

Stakeholder Process

The work plan also includes a process to encourage the Working Group to reach out to stakeholders and other experts to assist Staff in identifying and understanding the technical and policy challenges associated with developing options to address potential emissions leakage. As part of this outreach effort, the Working Group organized a two-day stakeholder workshop on June 15-16, 2006, to discuss various policy options under consideration. Presentations were made by policy and legal experts, as well as representatives of the three regional electric system independent system operators. Staff also reached out to independent experts during the drafting of this report.

Purpose of the Report

Although the MOU provides for a single report to Agency Heads by December 2007, the Working Group adopted a more aggressive approach, as noted in the work plan, which would result in the development of a preliminary and a final report.

The purpose of this preliminary report is to evaluate market dynamics that may lead to emissions leakage, propose monitoring options to track potential leakage, and provide a qualitative analysis of various policy options that might be used by the Signatory States to mitigate any potential leakage. This report also attempts, where possible, to evaluate potential emissions leakage mitigation mechanisms against criteria specified in the RGGI MOU.

Staff will prepare a final report after reviewing feedback from the Agency Heads, expert resources, and stakeholders. In the final report, Staff will undertake, where appropriate, a more detailed qualitative and quantitative analysis of the potential effects of the various policy options considered in the preliminary report.

Evaluation Criteria for Emissions Leakage Mitigation Mechanisms

To evaluate the different policy options available to address potential emissions leakage, Staff has identified the following criteria. In considering policy options, the states should evaluate the extent to which each option:

(1) accomplishes the goal of adequately addressing emissions related to the end-use of electricity in the most flexible, cost-effective manner;

[2] RGGI Emissions Leakage Working Group Work Plan, June 14, 2006. Available at http://www.rggi.org/docs/rggi_workplan_6_14_06.pdf

(2) maintains and/or enhances electric system reliability;

(3) ensures that electric power generated within the RGGI region is treated similarly to electric power generated outside the region;

(4) remains relevant even after a mandatory federal greenhouse gas reduction policy is in place;

(5) encourages energy efficiency and/or carbon efficiency in the generation and end-use of electricity; and

(6) is compatible with other energy and environmental policies that address the end-use of electricity.

II. The Emissions Leakage Debate

There is a debate as to whether or not the imposition of a carbon cap on power plants in the RGGI region will cause significant increases in emissions from electric generators not subject to the RGGI program. Obviously, this discussion presumes a scenario where a larger national program does not exist and the regional program being implemented does not fully cover the respective regional wholesale electricity market(s).[3]

The implementation of a carbon cap on in-region power plants is expected to increase the cost of electricity generation in the RGGI region. In a competitive power market, this may have the effect of shifting generation in the larger region to uncontrolled, and presumably cheaper, fossil fuel-fired generation not subject to a carbon cap.[4] This shift in generation and associated emissions from capped sources to non-capped sources is described as "emissions leakage". Implicit in this concept is the notion of causality; specifically that a cost increase due to a carbon cap could drive spatial changes in the operation of the electric power system. This is distinct from a shift in the spatial distribution of electric generation resulting from other market variables and the dynamic nature of the electric power market.[5]

---

[3] The implementation of a national CO_2 cap-and-trade program for the electric power sector that is equivalent to RGGI, or a scenario where RGGI sunsets once a national program is implemented, would remove any potential for emissions leakage. A scenario where a weaker federal program complements the RGGI program could still potentially result in emissions leakage, although this scenario would be expected to mitigate the potential for emissions leakage relative to a scenario in which RGGI is implemented in the absence of a federal program.

[4] This potential shift in generation could be to uncontrolled generation units both inside and outside the RGGI region.

[5] Some have advocated for a broader definition of emissions leakage, arguing that over time current market variables, absent RGGI, will lead to an increase in out-of-region generation and related emissions. According to this position, even if RGGI does not lead to emissions leakage, other market variables may undermine the emissions reduction gains achieved under the

The potential disparity in electricity generation costs between controlled and uncontrolled generation could result in increases in generation and related carbon emissions by uncapped higher-emitting plants that are able to sell power to load-serving entities (LSEs) in the regulated region, with possible decreases in generation and emissions from sources subject to the emissions cap. Since RGGI will be implemented in competitive wholesale electricity markets, there is the potential for LSEs to bypass their current generation providers, and to seek alternative sources of power supply. A disparity of generation costs between capped and uncapped generators could also lead to a spatial shift in dispatch of generators serving the wholesale spot market.

Market Dynamics

There is significant uncertainty related to the magnitude of the potential threat of emissions leakage and the manner in which emissions leakage may occur. Some argue that wholesale electricity market dynamics and the practices of market participants could result in a significant amount of emissions leakage. However, others contend that there are mitigating market dynamics and other factors that suggest that under a modest carbon cap such as RGGI, emissions leakage may not be significant, and that concerns for the integrity of the program may be over-stated.

The dynamics of a competitive electricity market could drive leakage if it provides a sufficient net financial incentive to shift generation to generation units not subject to a carbon cap. The extent of this impact is likely to depend, at least in part, on the value of CO_2 allowances (and the related $/MWh CO_2 compliance costs) in relation to other economic factors associated with the generation and delivery of electricity. These factors include locational marginal pricing (LMP), standard transmission pricing (including line-loss costs), transmission congestion charges, fuel prices, and relative heat rates of generation units. Reliability constraints will also play a role in determining the dispatch of RGGI units to the extent that RGGI units supply needed capacity and ancillary services within the RGGI region.

Currently there is insufficient information to make precise estimates as to the potential amount of emissions leakage that may occur over the course of the program. However, Staff concludes that key factors going forward will be the relative cost of generation inside and outside the RGGI region, and the relationship and interaction of this cost differential with physical transmission capability, the all-in market costs of inter-region power transmission, and the market impacts of transferring significant incremental amounts of power into the RGGI region. The dynamic and highly specific nature of forces that may cause or mitigate leakage makes future projections of emissions leakage difficult. The factors that may result in emissions leakage are likely to be both temporally and geographically specific, given the dynamic operation of the electric power system.

---

program unless all carbon emissions from electricity use in the region are addressed through a load-based policy.

The only empirical data related to emissions leakage impacts from a regional cap-and-trade program comes from the experience of the OTC NO_x Budget Program.[6] In the development of that program there was concern that there might be a shift in generation to upwind sources. A review of the OTC NO_x Budget Program indicates that any leakage that resulted was minimal. However, it is not clear whether the relatively low cost of NO_x controls, other program-related factors, or market conditions themselves were responsible for this outcome. Despite inconclusive evidence as to the effect of the cost of NO_x controls in the OTC NO_x Budget Program, it is still reasonable to expect that carbon compliance costs in the RGGI program have the potential to affect the relative economics of RGGI-affected generators in relation to uncapped generators.[7]

Locational marginal pricing (LMP[8]) can be expected to affect the market response to the imposition of a carbon cost adder to generation. Locational marginal pricing is based on the principle that the generation of power has different values at different points in the electric power network. LMP is the cost of supplying the next MWh of generation at a specific location, considering transmission constraints and the marginal cost of local generation units. [9] Market participants utilize finite transmission resources, and transfers of power in a region can impact the local generation economics in that area, due to the physics of the electric transmission network. Transmission "congestion" occurs when available, low-cost supply cannot be delivered to the demand location due to these limitations. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in this constrained area are dispatched to meet that load. The result is that the price of

---

[6] See Ozone Transport Commission, *NO_x Budget Program 1999-2002 Progress Report,* Ozone Transport Commission and U.S. Environmental Protection Agency, 2003; Aulisi, et al., *Greenhouse Gas Emissions Trading in U.S. States: Observations and Lessons Learned from the OTC NO_x Budget Program*, World Resources Institute, 2005.

[7] The average cost of NO_x control under the OTC NO_x Budget Program was estimated to be \$0.10-\$0.20 per MWh, although on a marginal basis it may have been higher (*e.g.*, NO_x allowances were priced at equivalent of \$0.40/MWh based on average values for 2000 ozone season). Aulisi et al., pp.13 - 16. By contrast, RGGI CO_2 allowance costs are projected to be significantly higher on a per MWh basis. The most recent Integrated Planning Model (IPM) modeling for the RGGI Staff Working group projects allowance prices of \$3/ton in 2015, rising from \$2/ton in 2009 at the program's outset. Based on average emissions rates in the U.S. a \$3/ton allowance price translates to compliance costs of approximately \$3/MWh for coal-fired units, \$2.20/MWh for oil-fired units, and \$1.50/MWh for gas-fired units. A natural gas combined cycle plant, with an emissions rate of 800 lbs. CO_2/MWh, would face a compliance cost of \$0.80/MWh at a \$2/ton allowance price, and \$1.20/MWh at a \$3/ton allowance price.

[8] Also referred to as "location-based marginal pricing", or LBMP, by New York ISO.

[9] One of the benefits of this price transparency is that LMPs reveal congestion costs in different portions of the transmission system. These price signals allow market participants to respond to changing conditions in various portions of the grid, reducing the need for system operators to administratively ration limited transmission resources. See, for example, *New York State Department of Public Service Staff Report on the State of Competitive Energy Markets: Progress To Date and Future Opportunities*, March 2, p. 19. For further background, see PJM, *Locational Marginal Pricing*, LMP-101 Training Materials, March 6, 2006. Available at http://www.pjm.com/services/training/downloads/lmp-101-training.pdf

energy in the constrained area is higher than in the unconstrained area due to a combination of demand, transmission limitations, and the marginal cost of local generation.

The RGGI s cap is projected to result in modest allowance prices of $2-3/ton through 2015, which translate to compliance costs of $0.80-$3.00/MWh (*e.g.*, approximately 5% or less of the average 2005 PJM wholesale price). If the cost of RGGI compliance on a per MWh basis is lower than the aggregate per MWh price signal of mitigating market factors, no net market dynamic driving emissions leakage would be expected to occur.[10] While emissions leakage is likely to be driven by site-specific factors, Staff notes that the average price signal from these mitigating factors, based on current market conditions, exceeds the projected compliance costs of RGGI on a $/MWh basis. These market factors that may impact the economics of importing incremental power in response to a carbon price signal include:

- *Existing generation price differentials* – Differential LMPs between regions represent the presence of transmission constraints that require the dispatch of higher priced generation in a certain region. In 2005, average load-weighted zonal LMPs in eastern PJM (NJ, DE, MD) averaged $4-8/MWh above the LMP at the PJM western hub, with the highest differential in the PSE&G zone in New Jersey, indicating the presence of existing transmission congestion.[11]

- *Congestion charges* – Congestion charges and the standard cost of transmitting electricity may make significant incremental imports into the RGGI region uneconomic as a response to a modest generation price differential resulting from a RGGI carbon cap. In PJM, power transmission is subject to congestion charges, which are based on the difference between LMPs at the source (generator location, or "generator bus") and LMPs at the sink (electric distribution utility location, or "LSE bus"). Thus, in addition to standard transmission charges, power purchasers importing power into the RGGI region would need to pay congestion charges based on the differential between LMPs in the uncapped region where the generator is located and LMPs in the capped RGGI region where the purchaser is located.

- *Line loss charges* – The greater the distance that electricity is transmitted, the greater the loss of the power initially put into the line. The costs of transmission line-losses impact the economics of importing power. For example, in PJM, firm point-to-point transmission (for PJM exports and "wheeling" of power through PJM) is charged for line losses at a percentage of the PJM load-weighted average LMP (3% on-peak and 2.5% off peak).

[10] This net market signal would be a function of the relationship between the generation cost differential due to RGGI and the all-in market cost of transferring incremental power into the RGGI region.
[11] PJM, *2005 State of the Market Report*, p. 299.

Based on PJM load-weighted LMPs for 2005, this translates to \$2.34/MWh on-peak and \$1.19/MWh off-peak. Non-firm point-to-point transmission is charged for line loses at \$0.67/MWh.[12]

Other factors, such as existing long-term power purchase agreements and the challenges associated with siting and developing new transmission capability, could affect the near- and mid-term emissions leakage potential.

Existing plant-specific long-term power purchase agreements can be expected to mitigate emissions leakage, especially in the near-term, since units that are subject to such agreements will continue to dispatch subject to the terms of the agreements once RGGI is implemented.[13] With existing contracts in place, LSEs are constrained from seeking alternative sources of generation supply. For example, some coal- and gas-fired units in New Jersey are subject to long-term firm power contracts.[14] Similarly, two thirds of Vermont's load is served under contracts that will stay in place until the 2012-2015 period. It is estimated that long-term contracts currently account for approximately 14% of electricity generation in the RGGI region, and could account for approximately 12% of regional generation in 2010.[15]

It has been suggested that the development of new transmission could be the most significant factor driving emissions leakage, because increased deployment of new transmission both into and within the RGGI region would result in greater transmission capability and (presumably) smaller inter-regional generation price differentials (reduced LMP differential), which would promote power flows into the region in response to a carbon cost adder in the RGGI region. Staff notes that the impact of new transmission would likely be more complex, due to the dynamic nature of the transmission system, than the generalized impacts that have been discussed in the context of RGGI. An example of these complex dynamics is the Neptune line, currently under construction from New Jersey to Long Island. Modeling by PJM projects that the Neptune line could raise average LMPs in New Jersey by 2-6%, depending on the control zone. This could be expected to affect the dispatch of units on Long

---

[12] PJM, *Overview of Market Settlements*, Transactions 201 Training Materials, February 24, 2005, pp. 48-53.

[13] In PJM, 40% of load in 2005 was served through the spot market. The remainder was served through bilateral contracts or self-scheduling of units. See PJM. *2005 State of the Market*.

[14] The PPAs referenced here are plant-specific. It should be noted that this is not the case for all long-term PPAs. With the advent of electricity restructuring, many PPAs with non-utility generators (NUGs) were renegotiated. These renegotiated contracts often granted generators the flexibility to dispatch on a merchant basis in exchange for reducing the price paid by the purchaser for delivered firm energy and capacity. The PPA seller retained the responsibility for providing energy and capacity to the purchaser from either the generation facility or other generation resources within the ISO. These types of PPAs would not be expected to mitigate emissions leakage.

[15] See Wilson et al., *The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative*, Resources for the Future Discussion Paper RFF DP 05-37, August 2005.

Island, to increase output of PJM base-load generation, and increase transmission congestion into and within New Jersey.[16] While an expected decrease in generation in Long Island could possibly represent emissions leakage, increased transmission congestion and an associated rise in LMPs in New Jersey would be expected to mitigate emissions leakage from New Jersey.

Significant new transmission, if built, is likely to come on-line in the post 2012 timeframe.[17] Many business executives expect a national carbon policy to be implemented between 2012 and 2015.[18] A national carbon cap would in large part address the emissions leakage issue.[19] As a result, Staff believes that the impact of new transmission capability is of limited concern as a short-term to mid-term issue for RGGI.

Modeling Projections

Electricity sector modeling conducted for the Staff Working Group evaluated the potential impact of emissions leakage. Modeling was performed by ICF Consulting using the Integrated Planning Model (IPM) and assumptions developed by the Staff Working Group in consultation with stakeholders. In brief, results indicated the following:

- While imports decrease across the region in the business-as-usual cases, the model generally projects an increase in imports with associated emissions leakage in the cap scenarios relative to the business-as-usual cases.

---

[16] See PJM, "PJM Market Simulation: Analysis of Possible Affect of Neptune Project on PJM Wholesale Electricity Prices," 2005.
[17] Staff notes that most of the transmission that has been recently proposed in the broader region would be constructed on a merchant basis and is therefore subject to significant uncertainty.
[18] Hoffman, A., *Getting Ahead of the Curve: Corporate Strategies that Address Climate Change*, Pew Center on Global Climate Change, October 2006.
[19] The implementation of a national CO_2 cap-and-trade program for the electric power sector that is equivalent to RGGI, or a scenario where RGGI sunsets once a national program is implemented, would obviate any potential for emissions leakage. A scenario where a weaker federal program complements the RGGI program could still potentially result in emissions leakage, although this scenario would be expected to mitigate potential emissions leakage.

- Under a “middle-of-the-road” scenario, cumulative emissions leakage was estimated at 27% of net CO_2 emissions reductions through 2015.[20]

- Higher allowance prices lead to a higher level of projected emissions leakage. Previous “middle-of-the-road” modeling runs that projected lower allowance prices than the most recent runs also projected lower cumulative emissions leakage of 18% through 2015.[21]

- Projected emissions leakage is predominantly in the form of a shift in the location of new natural gas-fired power plant builds, rather than decreased utilization of existing plants (Figure 1).

- Modeling results projected that the majority of incremental imports would enter and be used in the RGGI states that are part of the larger PJM regional transmission power pool.

- Program components that reduce the cost of the RGGI Program, such as cap stringency, offsets and other flexibility measures, and end-use energy efficiency reduce projected incremental imports.

Staff acknowledges that the IPM model presents limitations for estimating emissions leakage. Based on the discussion above, emissions leakage is likely to be impacted by a number of location-specific market variables. The IPM model uses an aggregation of the electric transmission system that does not fully capture these site-specific variables.

An analysis of the IPM modeling results also indicated that the majority of incremental imports were projected to come from new natural gas combined-cycle plants constructed outside the RGGI region, rather than a reduction in the utilization of existing plants (Figure 1). The model projected these new plants would be built within the RGGI region in the business-as-usual case, but shifted these plant builds to bordering states outside of the RGGI region after the cap was assumed.[22] The model was predicting that the very modest incremental cost to comply with RGGI would be enough to shift plant build locations, an outcome that Staff deems to be unlikely in the real world. Staff notes that power plant siting considerations are subject to a number of considerations not fully captured by the IPM model, including location-specific demand (as represented by LMPs), access to transmission, local siting and permitting considerations, and the ability to obtain a power purchase contract with an LSE or other party under suitable terms to secure project financing.

[20] This estimate is for the Staff Working Group scenario used as the primary basis for evaluating the potential impacts of RGGI (IPM runs dated October 11, 2006, available at http://www.rggi.org/documents.htm). This estimate is a percentage of net CO_2 emissions reductions achieved, which includes emissions reductions projected by IPM to be achieved through emissions offsets.

[21] IPM runs dated September 14, 2005, available at http://www.rggi.org/documents.htm.

[22] New plants are projected to be built to meet the projected increase in electricity demand in the RGGI region through 2024.

The anticipated participation of Maryland in RGGI by the middle of 2007 may also have an impact on potential emissions leakage.[23] A modeling analysis evaluating the impact of Maryland joining the RGGI program was commissioned by the Maryland Department of the Environment. Led by the University of

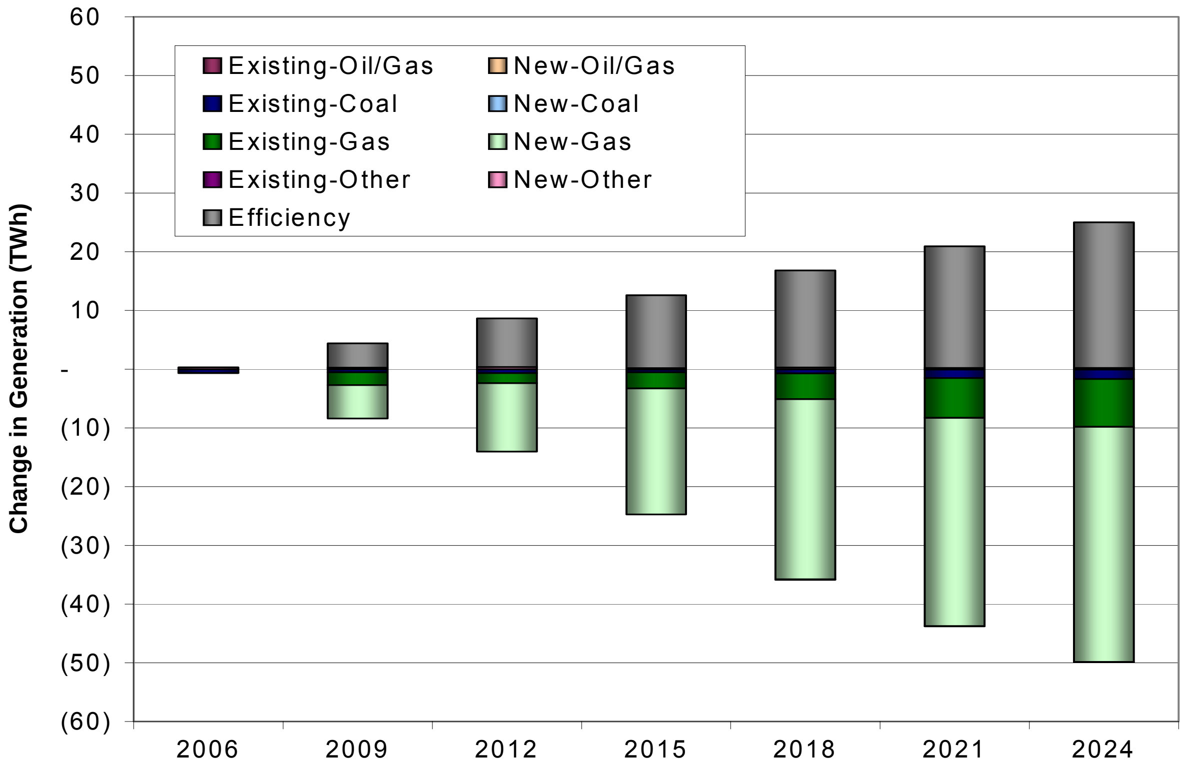

Figure 1. Change in RGGI Generation: Reference Case to RGGI Policy Case
(Source: ICF Consulting, January 2007. For IPM runs dated October 11, 2006.)

Maryland, the analysis found that the impact of the inclusion of Maryland was likely to have a very small impact on potential emissions leakage:

> Maryland joining RGGI initiates a series of changes in the electricity market and related fuel and allowance markets that are difficult to predict or model with precision. Because the changes are small, and the relationships complex, the results from the model are most useful when interpreted qualitatively. The bottom line is that according to the modeling exercise, Maryland joining RGGI is not expected to lead to an increase in

[23] Legislation passed in April 2006 requires Maryland to become a full participant in RGGI by June 30, 2007.

leakage beyond that which may already occur under the policy in the Classic [nine-state] RGGI region.[24]

Initial Conclusions

Staff conclude that it is prudent to expect emissions leakage to occur if the costs of acquiring in-region generation supply, including the $/MWh CO_2 compliance costs, exceed the all-in cost of acquiring alternate fossil fuel-fired generation supply that is not subject to a carbon constraint, including the cost of delivering power into the RGGI region. Without sufficient empirical data, however, it is unclear exactly to what extent carbon compliance costs will play a role in relation to the other market variables outlined above.

III. Proposal for Monitoring Potential Emissions Leakage

Tracking Electricity Transactions and Associated Air Emissions

Staff conclude that for the purpose of quantifying and determining the extent of potential emissions leakage, ensuring that leakage does not undermine the emissions reductions achieved by the program, and supporting RGGI's goals of monitoring emissions leakage, it is essential to be able to track and verify the environmental attributes associated with all the power being generated and used within the RGGI region, as well as the environmental attributes of power generated in adjoining regions.

To accomplish these goals, the questions that need to be answered are: (1) can RGGI quantify the amount of historic electricity use within the region, and determine the types of generation (and associated environmental attributes) that provided that energy? If yes, then (2) can RGGI monitor with sufficient accuracy, subsequent changes from historic wholesale electricity purchasing patterns, and the impact that these changes may have on emissions from uncontrolled generation serving the RGGI region, in order to determine whether emissions leakage is occurring?

This section provides an overview of existing tracking systems that could be used to evaluate emissions leakage, and outlines a specific proposal for tracking potential emissions leakage.

Background

Nearly ten years ago, in a report entitled, *Full Environmental Disclosure – Tracking and Reporting Key Information,* the National Council on Competition

---

[24] Center for Integrative Environmental Research, University of Maryland, College Park, *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, January 2007, pp. 36-38. Available at http://www.cier.umd.edu/RGGI/index.html.

and the Electric Industry posed the question, "Is it possible to know where electricity at a customer's meter came from?"[25] In response, the report elaborated:

> This simple question has a complex answer because electricity follows the laws of physics, not the computations of accountants. With an interconnected grid, the power flow over the transmission system is ambiguous. A relevant generalization is that power is put into the grid at certain points and taken out at other points. Which generator produced the power that went through a particular customer's meter is, in a physical sense, indeterminate, except in a very few cases.

However, continues the report:

> The fact that electrons cannot be traced back from a customer to a source has not impaired the ability of power producers and power suppliers to plan their systems, choose what to build and what to buy, inform consumers and others of the supplier's fuel mix or emissions or, most important, transact hundreds of billions of dollars of business.

In response to this need to account for electricity purchases and for the environmental attributes associated with these purchases, the three independent system operators in the northeast and Mid-Atlantic have developed systems to account for MWhs of electricity generated and MWhs of electricity used, as well as the environmental attributes related to these MWhs. Two of the three tracking systems in the northeast and Mid-Atlantic (those used by PJM and ISO New England) separate the environmental and other attributes of electricity generation (e.g., emissions, fuel type, generator location) from the underlying electricity commodity (e.g., MWh of electric energy). The third system, in New York, is undergoing modifications to incorporate similar capabilities.

Currently, these systems are used to track LSE compliance with specific portfolio requirements (renewable portfolio standards), and provide environmental disclosure to retail electricity customers (e.g., average pollutant emissions rates for control areas or LSEs). As discussed below, with certain modifications, RGGI should be able to use these systems to account for the amount of electricity used in the RGGI region and the environmental attributes associated with this electricity. With this information, RGGI could then monitor, with some degree of confidence, possible emissions leakage occurring after the start of the program.

[25] National Council on Competition and the Electric Industry, *Full Environmental Disclosure – Tracking and Reporting Key Information,* 1997. p. 5.

The Tracking Systems: PJM's GATS and ISO New England's GIS

The RGGI region includes three independent system operators (ISOs): New York ISO, PJM, and ISO New England. Each ISO has developed systems to account for environmental aspects of electric energy sold within their boundaries (control area): the New York Environmental Disclosure Program, the Generation Attribute Tracking System (GATS) in PJM, and the New England Generation Information System (GIS) (collectively "tracking systems").[26] The primary use of these tracking systems has been to ensure LSE compliance with specific state policies, primarily renewable portfolio standards and environmental disclosure requirements.

The GATS and GIS systems have accounts for individual generators and LSEs. These accounts keep track of MWhs generated and MWhs used to serve load. It is from these specific accounts that the region-wide generation and electricity load figures are aggregated. For any period, there is a known amount of electricity generated and a known amount of electricity used. After accounting for line loss and other factors (e.g., net exports or imports to or from other control areas, or use of pumped storage hydroelectric generation), these amounts must be equal.

As each generator produces electricity, the tracking system creates matching electronic certificates for each MWh of electricity in the generator's account. Each certificate has its own serial number, and contains descriptive "certificate fields." In the PJM GATS system, for example, certificates contain the following information:

- Plant name
- ORIS PL (Plant code for Department of Energy, Energy Information Administration reporting purposes)
- Emissions unit ID(s)
- Month and year of generation
- Certificate serial numbers
- Type of certificate
- Fuel type mix, and fuel type attributes
- Program eligibility (e.g., New Jersey Renewable Portfolio Standard)
- CEM reporting
- Peer unit name and address (if not reporting actual generator emissions)

[26] The tracking system used in New York is currently being modified, and is not being discussed here in detail. While it appears that the New York tracking system may develop into a system that will be compatible with ISO New England and PJM's current tracking systems, because the New York system is in transition, this discussion will focus upon the GATS and GIS systems. For further information about the development status of the New York system, refer to Appendix II.

- Normalized emissions rate (pounds per MWh), by pollutant
- Vintage (month and year of commercial operation)
- Repowering/derate date
- Capacity addition/subtraction
- FERC hydroelectric license (if applicable)
- Asset identification, including owner, status, capacity
- Location of generating unit
- NERC Region, county, state
- Import characteristics (if applicable)
- NERC tag (if applicable), date imported, compatible tracking system name, account holder

In PJM, some of the data used in certificates have been compiled using the PJM market settlement system (for generation data and LSE usage data) and publicly available emissions and fuel consumption data from the U.S. Environmental Protection Agency and the U.S. Energy Information Administration. Where data do not exist, PJM generators have the option to update their information based on "agreed upon best practices."[27] Where the information is still not available, default assumptions can be developed and used. In New England's GIS system, emissions data are likewise provided from various sources. The preferred order of sources is as follows: Continuous Emissions Monitoring or "CEMS" data, other emissions data reported to the state, stack testing data, and default emissions factors.[28]

In addition to accounting for energy and associated attributes generated within their control areas, both GATS and GIS account for net energy that is imported into their respective control areas. A certificate is produced for each MWh of imported energy. With the exception of imported electricity which is bought under a unit-specific bilateral contract, and which is purchased with associated attribute certificates reflecting that specific unit's emissions rate, certificates for attributes associated with imported energy are typically assigned the system-average environmental attributes for the control area from which they are purchased.[29]

In addition to accounting for each MWh of generation and net power imports, the tracking systems establish accounts for LSEs in order to track their electricity use. LSEs are required to register for an account with the tracking system. The LSEs also have sub-accounts in the tracking system for each state in which the LSE operates. These accounts contain information including the

[27] See GATS operating rules, at http://www.pjm-eis.com/documents/downloads/gats-operating-rules.pdf

[28] See GIS Rule 2.5(e)(4); see also GATS Rule 6.4.

[29] For example, New England's ISO imports electricity from adjacent control areas, including New York, New Brunswick, and Quebec. Each of those systems' average emissions rate is assigned to MWhs of imported power from those systems. Where units do not report in those systems, the worst-case emissions are assigned.

number of certificates representing MWhs purchased, and any attribute certificates purchased.[30] These accounts are used by LSEs in order to comply with specific policy requirements. For example, companies making marketing claims or those seeking to comply with a particular state portfolio standard or disclosure rules use the GATS or GIS account reports to support their claims to customers and to demonstrate compliance with regulations.

As the name suggests, these tracking systems create certificates and also keep track of the movement of certificates from generator accounts into LSE accounts. As mentioned above, when accounting for and tracking electricity generation, GATS and GIS separate the attributes from the underlying electricity commodity. In other words, MWhs of electric energy are accounted for separately from the associated environmental attributes of the underlying generation (*e.g.*, examples of generation attributes include fuel type, such as hydroelectric or gas; or emissions, such as lbs. CO_2/MWh). In some cases, for example, where a renewable portfolio standard calls for a demonstration that a company has acquired renewable energy (or renewable energy attributes), the attribute itself is acquired by an LSE. An example of how this works is provided below:

1. Generator X (small hydroelectric) gets a certificate (with a field indicating "small hydroelectric") for each MWh generated. The certificate is distinct from the MWh itself, *i.e.*, the attribute is bought/sold separately from the MWh of electricity.

2. LSE A has a plant-specific contract with Generator X and uses the MWhs supplied by Generator X to meet the LSE's load within the market settlement system. But, even though LSE A has paid for the electrons to meet its electric load, it does not have the right to the certificates representing the "small hydroelectric" attribute. These attributes thus remain available for sale to other parties.

3. LSE B has 100 MWhs of load, and needs 20% of that electricity supplied to be from renewable energy sources, in order to meet a renewable portfolio standard. LSE B meets its electric load obligation with 100 MWhs from Generator Y (a natural gas-fired plant). LSE B meets its 20% renewable energy requirement by buying 20 certificates from Generator X, which represent the attributes related to 20 MWh of generation from the hydroelectric plant. LSE B lets the

[30] See, for example, GIS Rule 4.3(a), Calculation of Certificates Obligation, which provides for the calculation by the GIS administrator, "on each Creation Date the Certificates Obligation of each Retail LSE for that Trading Period with multi-settlement data for Electrical Load in the applicable calendar quarter obtained from the System Operator…."

remaining 80 MWhs default to “residual system mix,” *i.e.*, the remaining mix of certificates not purchased by LSEs in the control area during that trading period.

In this example, certificates for environmental attributes associated with a small hydroelectric generation plant are created as Generator X produces power. When LSE B purchases 20 certificates, each certificate is transferred from Generator X’s account into LSE B’s account. The remaining 80 certificates in LSE B’s portfolio will have the attributes associated with the “residual system mix," as calculated by the tracking system.

For the above example, the average CO_2 emissions rate (lbs. CO_2/MWh) of the generation used by LSE B would be estimated based on the weighted average emissions rate of the certificates it holds. There is a zero emission rate for the 20 “small hydroelectric” certificates. The 80 “residual mix” certificates have a lbs. CO_2/MWh emissions rate that represent the weighted average emissions rate of the residual mix in LSE B’s control area.

Residual system mix is a term describing the aggregate attributes or content of certificate fields of all certificates that are not held by an LSE at the end of a trading period.[31] In practice, the residual mix represents the aggregate attributes (*e.g.*, average lbs. CO_2/MWh) of all remaining MWhs in the control area for which certificates have not been claimed by an LSE.

Certificates for a calendar year can typically be bought, sold or otherwise transferred anytime after the certificate is created until the relevant trading period closes. However, at the end of the certificate trading period, after a true-up period, unsold and unused certificates are retired. The attributes of these certificates are pooled to create what is known as "residual mix" certificates. Each LSE with unmatched load (*i.e*., with a greater number of MWhs of electricity delivered than certificates held) is allocated an equivalent number of "residual mix" certificates.

Using GIS as an example, the GIS Administrator is generally required to produce an electronic certificate for each MWh of energy generated by generation units included in the market settlement system, and units that are not separately metered but which provide data in keeping with GIS requirements.

---

[31] See, for example, GATS Operating Rules at Section 2:
Residual Mix Certificates: A Type of Certificate that is created at the end of the Trading Period with Attributes equal to the average of all unsold/unused Certificates and Certificates in the GATS Administrator’s Account (such as emergency imports), *i.e.*, Certificates that have not been transferred to any of the following Sub-accounts: CEPS, Reserve, or Retail LSE. Residual Mix Certificates will then be allocated proportionately to all LSEs who have fewer Certificates than the load they served (*i.e.*, do not have a one-to-one match with the MWh of load they served).

Residual mix and residual mix certificates, under the GIS rules, are established according to the requirements of GIS Rule 3.4, which provides:

> In order to ensure a MWh-for-MWh match of energy generated by GIS Generators and imported into the control area with certificates created and assigned, each MWh of energy reflected in the market settlement system for the applicable calendar quarter that does not have a certificate associated with it in a retail LSE's [account] at the end of the trading period shall be assigned certificates to be created by the GIS Administrator that reflect the certificate fields that are per MWh averages of the aggregate characteristics of the remaining unsettled certificates for that quarter . . . .[32]

The attributes represented by any unsettled certificate at the end of the trading period become part of the pool of attributes upon which the residual mix attribute certificates are based. The total number of residual mix certificates created for any trading period, having the characteristics described above, are equal to the sum of:

(i) the total number of Unsettled Certificates for that Trading Period;

(ii) the total number of Reserved Certificates[33] for such Trading Period;

(iii) the total number of MWhs of negative load, i.e., small-scale behind-the-meter distributed generation units not counted as generation supply by the ISO; and

(iv) the total number of Banked Certificates created in that trading period.[34]

In addition to providing LSE-specific accounting, GATS and GIS also aggregate specific information about electric generation and use in their respective control area to derive data about the attributes of the control area system mix. GATS publishes a PJM System Mix report that contains extensive information on, among other things, fuel type, number of certificates, percentage of the PJM mix, and pounds of pollutant – CO_2, NO_x and SO_2 – per MWh. GIS

[32] GIS Rule 3.4(b)

[33] GIS Rule 3.5(a) covers the creation and accounting for "reserved certificates". Reserved certificates are certificates sold "directly to third parties in good faith, arm's length transactions for reasonable value, independent of transactions involving Energy between those purchasers and their Retail LSEs." According to Rule 3.5, to "avoid the possibility of double counting Certificates, each Account Holder that sells a Reserved Certificate shall, at the time of such transfer, transfer such Reserved Certificate in the GIS to a specially designated Reserved Certificate account using the procedure described in Rule 3.1."

[34] GIS Rule 3.4

develops similar reports, and tracks CO_2, CO, Hg, NO_x, PM, PM_{10}, SO_2, and VOCs.[35]

<u>Adaptation of Generator Attribute Tracking Systems for Monitoring Emissions Leakage</u>

<u>Introduction</u>

The existing tracking systems are well suited for tracking emissions leakage. These systems are used to account for the environmental attributes of all power delivered by LSEs to their retail customers, representing both the environmental attributes of power generated within the control area where an LSE is located, and the environmental attributes of net power imports from each adjacent control area.

In addition to providing for LSE-specific accounting of environmental attributes, these tracking systems are also capable of generating aggregate reports to estimate the environmental attributes of all power delivered within a control area, as well as reports for categories of certificates that share a specific identifying field. For example, a system mix report would include the environmental attributes of all electric generating units within the control area, as well as the estimated environmental attributes of the net power imported into the control area. These aggregate reports could include data on the type of generation used to serve load in the control area (e.g., 50% coal, 20% nuclear, etc.) as well as emissions data, such as lbs. CO_2/MWh for the control area as a whole. More specific reports could also be generated to account for the environmental attributes of a certain category of generator, such as the CO_2 lbs./MWh emissions rate of all natural gas-fired generation in the control area.

Staff proposes that for each control area, tracking of emissions leakage could be accomplished as follows. Data from each of the control areas fully or partially subject to RGGI would be aggregated to track potential emissions leakage for the RGGI region as a whole.

RGGI would regulate CO_2 emissions by all fossil fuel-fired electric generation units that are 25 MW or larger (RGGI-affected units) located in a state that implements regulations based on the RGGI cap-and-trade program (in aggregate, “RGGI region” or “in-region”). In order to track emissions leakage, a tracking system would account for the in-region load that is being met by generation units other than those units subject to the RGGI cap-and-trade program, and the environmental attributes related to this generation. If emissions leakage occurs, it can be expected to result from increased dispatch of either (a) in-region, non-RGGI units (i.e., those fossil fuel-fired units smaller than 25 MW),

[35] See Appendix I-A and I-B for details of the data reported by both systems.

(b) out-of-region fossil fuel-fired generation serving load in the RGGI region (imports), or a combination of the two (both of which are referred to as "non-RGGI generation").

To build the capacity for tracking potential emissions leakage, Staff recommends pursuing minor modifications to the existing tracking systems that would distinguish RGGI generation units from others units serving load in the RGGI region. These modifications would create certain new certificate identifiers and would also provide for the ability to create new data reports for certain categories of identifiers. By distinguishing between RGGI units and others, and tracking the environmental attributes of net imports into control areas subject to RGGI, it will be possible to ascertain the current level of load being served by generation units not subject to RGGI, and the related environmental attributes of this non-RGGI generation.

An initial estimate of emissions leakage could be established by tracking changes over time to the level of non-RGGI generation serving RGGI-region load, and changes in the associated CO_2 emissions related to this non-RGGI generation. It should be noted that this approach would not address causality, but instead would track emissions relative to an established emissions baseline for non-RGGI generation units that serve load in the RGGI region. Any increase in emissions for this category of generation units would be considered an initial estimate of emissions leakage. Causality, if addressed, would need to be evaluated on a parallel basis through an evaluation of changes in other market and power system variables during the monitoring period.

<u>Proposal</u>

Staff proposes to explore with the administrators of the ISO tracking systems the creation of new certificate fields for categories of generation units in the RGGI region. Modifications would also allow for the generation of new types of data reports that could be used for emissions leakage tracking purposes.

Under this proposal, each MWh produced in a control area fully or partially subject to RGGI would have an associated certificate with a field which identifies it, as applicable, as:

- "RGGI-affected unit" (e.g., $\geq$ 25 MW fossil fuel-fired unit subject to RGGI cap-and-trade program);
- "unaffected small fossil fuel-fired RGGI-region unit" (e.g., < 25 MW fossil fuel-fired unit not subject to RGGI cap-and-trade program, but located within a jurisdiction subject to RGGI cap-and-trade program); and

- “RGGI-region unit” (e.g., a unit located within a jurisdiction subject to RGGI cap-and-trade program).

In order to determine how much non-RGGI generation is serving load in the RGGI region, the same netting-out process currently used by the existing tracking systems to derive residual system mix attributes would be used. Under this approach, certificates associated with RGGI-affected units in a control area would be subtracted, leaving certificates for those units not subject to the RGGI program, as well as certificates representing net imports into the control area. The weighted average lbs. CO_2/MWh emissions rate for all remaining certificates would represent the lbs. CO_2/MWh residual mix. This “RGGI residual mix” would represent the environmental attributes of all remaining generation used to serve load in a control area subject to RGGI (including net imports), after subtracting generation from units subject to RGGI. The total number of residual mix certificates multiplied by the emissions rate of the residual mix would represent the number of tons of CO_2 emissions attributable to non-RGGI generation serving load in the RGGI region. Based on this monitoring of electricity use and tracking of electric generation environmental attributes, an estimate of emissions leakage could be developed and tracked over time.

With both RGGI units and non-RGGI units explicitly accounted for, it would be possible to establish a baseline of MWhs and associated environmental attributes (CO_2 emissions) for the non-RGGI generation being used to serve load in the RGGI region. Because emissions leakage would represent increased CO_2 emissions associated with the dispatch of non-RGGI units, the measurement of changes relative to the emissions baseline for non-RGGI units could serve as an initial estimate of emissions leakage. This emissions leakage estimate would represent a change in CO_2 emissions relative to a baseline for both electric generating units located outside a control area or partial control area subject to RGGI as well as electric generating units that are not regulated under RGGI, but are located within a control area or partial control area subject to RGGI.

An example of how this would work for an individual control area is presented below. Data from each control area fully or partially subject to RGGI would be totalled to track emissions leakage for the RGGI region as a whole.

Attribute Tracking

The following attributes would be tracked. Some of these represent new attributes that would be tracked for RGGI emissions leakage monitoring, while others are currently tracked by the existing tracking systems.

In-Region Generation: New generation attribute identifiers would be developed for the following:

- "*RGGI-affected unit*": unit subject to RGGI carbon cap-and trade program (e.g., fossil fuel-fired units $\geq$ 25 MW)

- "*Unaffected small fossil fuel-fired RGGI-region unit*": includes fossil fuel-fired units located in the RGGI region, but not subject to RGGI cap-and-trade program (e.g., fossil fuel-fired units < 25 MW)

- "*RGGI-region unit*": includes RGGI-affected units and all other units located in the RGGI region (e.g., a unit located within a control area fully subject to RGGI or located within the RGGI portion of a control area partially subject to RGGI)

Net Imports: Net imports would be tracked as follows:

- For NY-ISO and ISO-NE, the net power flows from each adjoining control area would be tracked directly, and certificates would be created to account for the attributes associated with each MWh of net imports, as is done currently by the existing tracking systems. The environmental attributes for these certificates are aggregated from the average emissions attributes of all generation in an adjoining control area (*e.g.*, average lbs. CO_2/MWh).

- For PJM, net "imports" into the RGGI portion of PJM would be inferred based on the difference between total load in the RGGI portion of PJM and total generation in the RGGI portion of PJM. Any deficit would be assumed supplied by system power, except that for the purposes of RGGI tracking, the environmental attributes of this system power would be limited to the attributes of generation units located outside the RGGI portion of PJM. The environmental attributes applied to this generation would be based on a non-RGGI PJM residual mix. This would include the weighted average emissions rate (lbs. CO_2/MWh) of all generation from generation units located in the non-RGGI portion of PJM. The amount of inferred net "imports" (MWh) would determine the number of certificates to which the non-RGGI PJM residual mix attributes would be applied.

Data Reports

With the information described above, the tracking system could provide the following information.

Electricity demand: Total load (MWh) for a control area or partial control area subject to RGGI would be based on the following:

- Reported MWh load for all LSEs in a control area or partial control area subject to RGGI. This data would be derived from control area market settlement systems.

Total generation: Total generation (MWh) for a control area or partial control area subject to RGGI, would be based on the following:

- Sum of certificates with a “RGGI-region unit” identifier.

RGGI emissions mix: The average CO_2 emissions rate (lbs. CO_2/MWh) of all generation units subject to the RGGI cap-and-trade program located in a control area or partial control area would be tracked based on the following:

- Weighted average emissions rate (lbs. CO_2/MWh) for all certificates with a “RGGI-affected unit” identifier.

RGGI residual mix: The average CO_2 emissions rate (lbs. CO_2/MWh) of all non-RGGI generation (including net imports) used to serve load in a control area or partial control area subject to RGGI, would be based on the following:

- The weighted average emissions rate (lbs. CO_2/MWh) of all remaining certificates, after subtracting all certificates with a “RGGI-affected unit” identifier.

Unaffected small fossil fuel-fired RGGI-region unit emissions mix: The average emissions rate for small fossil fuel-fired units not subject to RGGI, but located within a jurisdiction subject to RGGI, would be based on the following:

- Weighted average emissions rate (lbs. CO_2/MWh) of all certificates with an “unaffected small fossil fuel-fired RGGI-region unit” identifier.

Emissions Leakage Estimates

Emissions leakage would be tracked based on changes in the emissions from non-RGGI generation, *i.e.*, unaffected fossil fuel-fired units within the RGGI region and net imports, relative to a historic emissions baseline. The emissions totals would be derived by multiplying the number of applicable certificates by the carbon emissions attributes (lbs. CO_2/MWh) of these certificates. Initial estimated emissions leakage would represent an increase in emissions relative to the respective emissions baseline. Different data reports could be generated to estimate total emissions leakage, as well as subtotals due to certain categories of power, such as net imports or fossil fuel-fired generation not subject to the RGGI cap-and-trade program.

Total emissions leakage estimate for each control area: Total CO_2 emissions due to non-RGGI generation serving load in a control area or partial control area subject to RGGI, would be determined based on the CO_2 emissions attributes represented by the RGGI-residual mix certificates.

Estimated emissions due to out-of-region non-RGGI generation: Emissions leakage due to net power imports into a control area, or inferred net "imports" into a partial control area subject to RGGI, would be determined based on the weighted average emissions rate for certificates representing net power imports. These net imports would be tracked directly for both NY-ISO and ISO-NE and inferred for PJM. A weighted average emissions rate could be developed for all net power imports or individually for net imports from each adjoining control area.

Estimated emissions leakage due to in-region non-RGGI generation: Emissions leakage due to small fossil fuel-fired units not subject to RGGI would be determined based on the weighted average emissions rate for certificates with an "unaffected small fossil fuel-fired RGGI-region unit" identifier.

Sample Calculations

Sample calculations for a hypothetical control area are outlined in Box 1 through Box 3. The examples in Box 1 through Box 3 are representative of a control area that is fully subject to RGGI (e.g., NY-ISO or ISO-NE). The RGGI residual mix approach provides an estimate of CO_2 emissions from non-RGGI generation for the control area as a whole. The individual attribute tracking approach provides an estimate of individual emissions leakage components, such as that due to small fossil fuel-fired units within the control area, as well as net power imports from an adjoining control area. The combined total emissions for these emissions leakage components is equal to the emissions leakage estimate for the entire control area arrived at through the RGGI residual mix approach.

Box 1. Assumptions

Monitored RGGI Control Area:

Total load for control area: 1,000 MWh

Load for LSE #1: 500 MWh; Load for LSE #2: 500 MWh

RGGI-affected generation: 500 MWh (assume RGGI generation serves load equally among LSE #1 and LSE #2)

Small fossil generation: 50 MWh (average emissions rate, based on weighted average of certificate emissions attributes – 1,700 lbs. CO_2/MWh)

Net imports from adjoining control area: 100 MWh

RECs held by LSE #1: 100 (50 from within control area; 50 from adjoining control area); RECs held by LSE #2: 0

Adjoining Control Area:

System average emission rate: 1,500 lbs. CO_2/MWh

Other assumptions: Assume LSEs in monitored RGGI control area cannot claim any plant-specific bundled electricity transactions (electricity *and* attributes) with EGUs in adjoining control areas and can only claim RECs)

Box 2. RGGI Residual Mix

Monitored RGGI Control Area Residual Mix:

Residual MWhs for RGGI control area: 1,000 – 500 {RGGI units} – 100 {total RECs held by LSEs} = 400 MWh

Residual mix emissions rate for RGGI control area:

[(1,500 lbs. CO_2 x 100) + (1,700 lbs CO_2 x 50)] / 400 MWh = 587.5 lbs CO_2/MWh residual mix emissions rate
{Net imports} {Small fossil}

LSE #1:

Residual mix MWhs for LSE #1:
500 MWh {total LSE load} – 250 {RGGI unit certificates} – 100 {RECs} = 150 MWh {assumed "non-RGGI generation" for LSE #1, after adjusting for RGGI units and RECs}

Residual mix emissions for LSE #1:

587.5 lbs. CO_2/MWh x 150 MWh = 88,125 lbs. CO_2

LSE #2:

Residual mix MWhs for LSE #2:
500 MWh {total LSE load} – 250 {RGGI unit certificates} – 0 {RECs} = 250 MWh {assumed "non-RGGI generation" for LSE #2, after adjusting for RGGI units and RECs}

Residual mix emissions for LSE #2:

587.5 lbs. CO_2/MWh x 250 MWh = 146,875 lbs. CO_2

Total CO_2 emissions due to "non-RGGI generation" for LSE #1 and LSE #2: 235,000 lbs. CO_2

Box 3. Direct Attribute Tracking

Net imports from adjoining control area (as directly monitored at adjoining control area proxy bus): 100 MWh

Assumed emissions of net imports:

1,500 lbs. CO_2/MWh x 100 = 150,000 lbs. CO_2

Small fossil emissions:

1,700 lbs CO_2/MWh x 50 = 85,000 lbs. CO_2

Total emissions:

85,000 + 150,000 = 235,000 lbs. CO_2

Total CO_2 emissions due to "non-RGGI generation" for control area: 235,000 lbs. CO_2

Calculations would be similar for the RGGI states in PJM (partial control area), except that net imports would be inferred rather than directly tracked, and separate residual mixes would be developed for both the non-RGGI portion of PJM and the portion of PJM subject to RGGI. The residual mix for the non-RGGI portion of PJM would be used to determine the emissions attributes applied to inferred net "imports" into the RGGI portion of PJM. The residual mix for the portion of PJM subject to RGGI would be used to estimate emissions due to non-RGGI generation serving load in the RGGI portion of PJM through the same process outlined in Box 1 through Box 3 above. This RGGI residual mix would include emissions attributes for both inferred net "imports" and small fossil fuel-fired generation not subject to the RGGI program, but located within the portion of PJM subject to RGGI.

Recommendations

To support this monitoring proposal, Staff recommends that the RGGI-participating States take the following actions:

- First, explore modifications to the existing generator attribute tracking systems in the region (PJM's GATS, New England ISO's GIS), and the emerging tracking system currently under development by New York, in order to:

  (i) determine how much electricity is being used in a control area or partial control area subject to RGGI (including that supplied by generation from within and outside of the RGGI region);
  (ii) determine the environmental attributes associated with the generation of electricity both inside a control area or partial control area subject to RGGI and in adjoining regions;
  (iii) create generation attribute identifiers for "RGGI-affected unit", "unaffected small fossil fuel-fired RGGI-region unit", and "RGGI-region unit";
  (iv) track net imports into NY-ISO, PJM, and ISO-NE from adjoining control areas and account for related environmental attributes;
  (v) Infer net "imports" into the RGGI portion of PJM and account for related environmental attributes; and
  (vi) generate data reports for "RGGI residual mix", "unaffected small fossil fuel-fired RGGI-region unit emissions mix", and "RGGI emissions mix".

- Second, urge PJM and ISO-New England to make, within the next 12 months, the necessary modifications to GATS and GIS, respectively, that will enable the collection of data and regional coordination among attribute tracking systems necessary to monitor regional emissions leakage;

- Third, urge the New York PSC to coordinate with PJM and ISO-New England in order to include the features that will enable the collection of the necessary data in the tracking system that New York is currently developing, with the goal of being able to begin collecting the RGGI-related data within the next 12 months; and

- Fourth, using the approach outlined in this report, begin monitoring prior to the start of the RGGI program to evaluate CO_2 emissions from non-RGGI generation in order to develop baseline data.

Furthermore, Staff recommends that when developing emissions leakage monitoring capabilities for RGGI, attention should be paid to incorporating technical capabilities and design elements that would support the implementation of load-based policies to address emissions leakage. Staff acknowledges that the technical capabilities and design elements needed for RGGI monitoring could form the basis of a significant portion of the tracking systems needed to implement policies such as an emissions portfolio standard or a load-based emissions cap. Such design work should be considered now, as monitoring capabilities are developed, in order to enable a more rapid implementation of load-based policies if they are considered warranted.

IV. Policy Options to Address Potential Emissions Leakage

Introduction

This portion of the report evaluates, from a qualitative standpoint, various policy options to address potential emissions leakage. These policy options were initially raised and discussed by stakeholders, independent experts, and RGGI Staff Working Group members during the May 2006, Imports and Leakage Workshop at Vermont Law School. The report analyzes various policy options and the degree to which they meet certain criteria set out in the RGGI MOU, including the effectiveness of each policy in addressing emissions leakage, and the impact of mitigation policies on electric system reliability.

Each policy option is described, and then followed by a discussion of its efficacy in mitigating potential emissions leakage and implementation challenges that the policy option may present. Staff has organized the discussion of possible policy responses into the following three categories: (1) policies that indirectly address carbon emissions by reducing electricity demand; (2) policies that address, but do not cap, carbon emissions; and (3) policies that cap carbon emissions. A characteristic shared by all of these policies is that they address the end-use of electricity and the emissions that indirectly result from end-use.

1. Policies that Reduce Electricity Demand

A policy package that implements aggressive measures to reduce electricity load is expected to reduce RGGI compliance costs by reducing the demand for CO_2 allowances. This, in turn, will reduce the generation cost differential between electric generators subject to a carbon cap and those that do not face a carbon constraint, which is expected to mitigate potential emissions leakage. Analysis conducted by the RGGI Staff Working Group, including quantitative energy sector modeling, indicates that aggressive reduction of electricity demand in the RGGI region will lower RGGI CO_2 compliance costs, as represented by projected allowance prices, and could fully mitigate potential emissions leakage.[36]

Energy Efficiency Leakage Mitigation Policy Package

Description and Implementation

RGGI-participating states could cooperate in implementing a package of policies that reduce electricity demand in the RGGI region, as a coordinated compliment to the supply-side focus of the RGGI cap-and-trade-program. A RGGI demand-reduction policy package could be coordinated through a standing multi-state agency head level committee, and might include the following:

- Implementation of an energy efficiency portfolio standard for load-serving entities in the RGGI participating states
- Maximization of RGGI allowance allocation dedicated to support for end-use energy efficiency
- Harmonization of building codes and standards across RGGI participating states at the most stringent current and future energy codes, for both commercial and residential buildings
- Harmonization of appliance and equipment energy efficiency standards across RGGI participating states
- Joint development and implementation by RGGI participating states of policies to reduce market barriers to combined heat and power applications

[36] IPM modeling results evaluating a high-efficiency scenario indicated that an 8.8% reduction in 2021 electricity demand in the RGGI region, relative to projected business-as-usual demand, would result in a significant reduction in CO_2 allowance costs and prevent any incremental increase in power imports and related emissions leakage. See, "Updated Reference and Sensitivities," September 8, 2005, available at http://www.rggi.org/docs/ipm_docs_results_9_8_05.ppt

Delivery of these goals could be articulated in an amendment to the RGGI MOU, and supported by coordinated multi-state development of certain model regulations, such as those required to implement an energy efficiency portfolio standard. A brief discussion of key energy efficiency policy options is provided below.

Energy Efficiency Portfolio Standard

Under an Energy Efficiency Portfolio Standard (EEPS) a state utility commission or other regulatory body specifies a numerical energy savings target (or targets) that LSEs must meet, on an annual or cumulative basis. An EEPS could be set as a percentage of load growth or base year sales, or as a fixed number of units of energy savings. An EEPS target could also cover peak electricity demand. States have found that establishing an explicit, mandatory target, based on sound analysis of technical and economic potential, can help overcome market barriers, regulatory disincentives, or insufficient information about the benefits of energy efficiency that hinder full investment in cost-effective energy efficiency. The adoption of an EEPS would also allow for the achievement of economies of scale, because the entity-wide EEPS targets allow energy providers to aggregate savings across multiple end-uses and sectors to meet the overall energy savings goal in the most cost-effective manner.

Building Energy Codes and Standards

Incorporated as part of state building codes, energy codes prescribe minimum standards for the energy efficiency of buildings that apply to both new construction and major building renovations.[37] All construction activities – including remodeling and renovation – can be significant drivers of demand for electricity, but also present unique opportunities for achieving demand reductions. Building energy codes typically specify requirements for "thermal resistance" in the building envelope, minimum air leakage, and minimum heating and cooling equipment efficiencies. These simple measures can reduce energy use by 30% or more, resulting in net savings for businesses and consumers.[38] Building energy codes serve to lock efficiency gains into the marketplace and provide an efficiency "floor" for market transformation programs.

Several states in the RGGI region have adopted the 2003 IECC code for both residential and commercial buildings, while others have adopted earlier

[37] The International Energy Conservation Code (IECC), last updated in 2005 (2006 version), sets standards for residential construction. The American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 90.1, last updated in 2004, sets standards for commercial building construction. The IECC also contains prescriptive and performance-based commercial building provisions. By referencing Standard 90.1 for commercial buildings, IECC offers designers alternate compliance paths.

[38] U.S Environmental Protection Agency, *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States,* April 2006. Available at http://www.epa.gov/cleanenergy/stateandlocal/guidetoaction.htm

versions. Appendix IV, Tables 1 and 2, provide an overview of the status of both residential and commercial building energy codes for the RGGI region.

According to an analysis by the Northeast Energy Efficiency Partnership (NEEP), the implementation of up-to-date building energy codes would reduce load in New England by 1,100 GWh by 2013.[39] Based on additional analysis by the RGGI Staff Working Group and NESCAUM, the potential reduction in electricity use due to region-wide adoption of up-to-date building energy codes is estimated at 5,900 GWh in 2020, equivalent to 1.3% of projected electricity use in the RGGI region.[40]

While RGGI states have recognized the value in adopting building energy codes, the level of code stringency varies across the region. A significant amount of reduction in electricity demand, and associated emissions, could be achieved through ongoing region-wide adoption of the most recent building energy codes, coupled with education and rigorous enforcement programs that achieve a high level of compliance.

Appliance and Equipment Energy Efficiency Standards

Appliance and equipment energy efficiency standards establish minimum energy efficiency levels for classes of commercial and residential appliances or equipment. Many states are implementing appliance and equipment energy efficiency standards, where cost effective, for products that are not already covered by federal mandates.[41] Efficiency standards ensure that as existing equipment stock is slowly turned over, new equipment meets minimum efficiency standards. Efficiency standards serve to lock efficiency gains into the marketplace and provide an efficiency “floor” for market transformation programs.

According to a study by the American Council for an Energy-Efficient Economy (ACEEE) and the Appliance Standards Awareness Project (ASAP), the adoption of appliance and equipment energy efficiency standards in the RGGI region could result in energy savings of approximately 8,600 GWh by 2020[42] equivalent to a 1.8% reduction in regional electricity use.[43]

---

[39] Northeast Energy Efficiency Partnership, Inc., *Economically Achievable Energy Efficiency Potential in New England*, November 2004 (Updated May 2005).

[40] Percentage load reduction estimate was calculated based on forecasted demand growth data used in RGGI IPM modeling analysis.

[41] The Energy Policy Act of 2005 (EPAct 2005) preempts states from setting their own standards for the products covered by federal standards. States that had set standards prior to federal enactment may enforce their state standards until federal standards become effective. For further discussion of the effects of EPAct 2005 on state standards, see Appendix IV, Table 3.

[42] Nadel et al., *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards,* ACEEE Report Number A051 and ASAP Report Number 5, 2005. Available at http://standardsasap.org/stateops.htm

[43] Percentage load reduction estimate was calculated based on forecasted demand growth data used in RGGI IPM modeling analysis.

Appendix IV, Table 3, provides an overview of the status and implementation dates for 25 appliance and equipment standards for 11 states, the majority within the RGGI region.

Combined Heat and Power (CHP) Systems

Combined Heat and Power (CHP) systems (also known as co-generation) are electric generation systems that utilize waste heat for space heating, cooling, and/or industrial processes. Electricity generation from central-station power plants wastes, on average, approximately two-thirds of its primary energy input. By utilizing waste heat, CHP systems produce both useful heat and power from one fuel source, and can achieve thermal efficiencies in excess of 80% percent.[44]

There is significant potential to increase the utilization of CHP in the RGGI region. According to a 2005 analysis conducted by Energy and Environmental Analysis, Inc., there is approximately 24,000 MW of technical potential for CHP available in the RGGI region.[45] Comprehensive research on the economically achievable potential for CHP development in the RGGI region has not been conducted. However, assuming that ten percent of the technical potential in the region is realized by 2020**,** 19,000 GWh of electricity use could be displaced from the electric grid, equivalent to 4.1% of projected electricity use in the RGGI region.[46]

Policy Strengths and Effectiveness

Increasing commitments to well-designed energy efficiency programs and standards, such as the suite of policies described above, is a no-regrets strategy that would provide continued reductions in both electricity and natural gas demand. These reductions would result in direct regional economic benefits by lowering wholesale energy costs, avoiding the need for new transmission and distribution infrastructure, improving electricity system reliability, and lowering consumer energy bills.

Each one of these policies is designed to reduce electricity demand, and therefore can be expected to help indirectly reduce emissions leakage. To the degree that electricity demand is reduced, the demand placed on existing generation resources is reduced, and the need to develop new generation capacity is avoided. This reduction in demand for generation supply results in avoided emissions, which, in turn, reduces the demand for CO_2 allowances. This would reduce the generation cost differential imposed on RGGI-affected generation units relative to generation units that are not subject to a carbon constraint.

[44] Prindle, et al., *Energy Efficiency's Next Generation: Innovation at the State Level*, American Council for an Energy-Efficient Economy, ACEEE Report Number EO31, November 2003, p. 13.
[45] Based on data provided by Energy and Environmental Analysis, Inc. to NESCAUM and additional NESCAUM analysis.
[46] Percentage load reduction estimate was calculated based on forecasted demand growth data used in RGGI IPM modeling analysis.

Challenges and Implementation Issues

While the impact of a reduction in electricity demand has been demonstrated to reduce wholesale and retail energy prices, the relationship is indirect. Determining the amount of energy efficiency resource that would be required to adequately mitigate emissions leakage, given an assumed CO_2 allowance price and generation cost differential, would depend on future projections arrived at through modeling. Staff notes that modeling conducted for the RGGI Staff Working Group broke new ground in integrating demand-side energy efficiency resources into supply-side electricity sector modeling, and could be used as a starting point for such an analysis.

Staff also notes that energy efficiency policies would have a limited impact on reducing the carbon intensity of the generation portfolio used to serve load. Energy efficiency policies that reduce the CO_2 allowance price to zero (and, by extension, remove the generation cost differential that could drive emissions leakage) would fail to achieve some of the goals and benefits of a generator-focused cap-and-trade program, which is to modify the dispatch and carbon intensity of the existing portfolio of generation units and incorporate emissions performance into the evaluation of future generation resources. As a result, a positive RGGI allowance price is needed to achieve emission reduction gains from the electric generation sector, and should be seen as complimentary to end-use energy efficiency policies. However, energy efficiency policies, to the extent that they result in the deployment of significant energy efficiency resources, would facilitate a lowering of the emissions cap over time.

Designing and implementing demand-side policies on a regional level would require a coordinated commitment from the RGGI signatory states. Harmonization of these efforts would promote the expansion of energy polices necessary to reduce electricity demand growth in the region. Presuming high-level commitment is obtained from decision-makers, the RGGI states should evaluate current programs and then develop "best practices" for designing and implementing policies and programs. Key design issues, such as setting targets, identifying funding sources and mechanisms, duration of program, appropriate market and program design analysis, stakeholder involvement, and coordination with other state and federal programs would be central to the collaborative effort. These efforts could rest with Agency Heads and their respective staff or be coordinated through the RGGI Regional Organization (RO).[47]

2. Carbon Adder and Emissions Rate Mechanisms

A more direct way to control emissions leakage than reducing demand for electricity is to impose a responsibility for carbon management upon load serving entities (LSEs), the primary market participants who make purchasing decisions

[47] Once established, the RO will be charged with providing technical support for the ongoing administration of the RGGI Program, as outlined in the RGGI MOU.

for electricity supply. Two policy mechanisms that require LSEs to include the consideration of carbon emissions into their energy resource planning and procurement strategies are, respectively, a carbon procurement adder or carbon procurement emissions rate, and an emissions portfolio standard.

Carbon Procurement Adder

Description and Implementation

The carbon procurement adder is an analytical tool used as a portfolio management strategy for utility planning purposes. This mechanism was recently implemented by the California Public Utilities Commission as a portfolio management requirement.[48]

A carbon procurement adder requires an LSE planning its electricity supply resource acquisitions to incorporate a "shadow price" for carbon emissions into its evaluation of different investment options. A carbon adder incorporates the price of carbon into the financial analysis of different generation supply options, and therefore incorporates the CO_2 emissions performance of an investment option into the calculus of whether it is deemed to be the least-cost option.[49] Taking the cost of carbon into account can potentially change the type of generation resource considered the least-cost option, depending on the relative economics of the supply options evaluated and the carbon price applied.

For implementation as a RGGI emissions leakage mitigation mechanism, the carbon adder applied could be equivalent to the RGGI CO_2 allowance price.

Policy Strengths and Effectiveness

As an emissions leakage mitigation option, a carbon procurement adder would remove any financial incentive for an LSE to change its procurement practices to evade the wholesale carbon price adder due to RGGI, at least for plant-specific bilateral power purchases. On its face, this would remove RGGI as a causal factor from any incremental increase in emissions from non-RGGI generation due to LSE power purchasing practices, at least for plant-specific bilateral purchases.

However, a carbon procurement adder would be of limited utility in addressing the carbon intensity of spot market power purchases, as this is a mix

[48] *See* California Public Utilities Commission Decision 04-12-048, December 16, 2004. This decision recognized the need for a "GHG adder" when evaluating fossil and renewable generation bids, a method designed to "serve to internalize the significant and under-recognized cost of GHG emissions, help protect customers from the financial risk of future climate regulation, and continue California's leadership in addressing this important problem." *Id*. at 3-4.

[49] The carbon adder only applies to the financial evaluation of different supply options. It is not included in the price paid for supply.

of system power including both low-emitting and high-emitting units. A carbon procurement adder applied to spot market power would increase the evaluated price of this power, by including an assumed carbon price adder based on the average CO_2 emissions rate related to this power. [50] The carbon adder could therefore impact the decision to purchase spot market power as opposed to other supply options. However, the application of the carbon adder would not address the relative carbon intensity of the different generation sources that constitute the spot market power offered. Simply put, the LSE could simply choose whether or not to purchase spot market power, based on the evaluation of that power with a carbon adder. However, LSE purchasing decisions based on this carbon analysis might not change the mix of generation offered into the spot market.

The mix of generation units dispatched in the spot market is based on bids submitted by generators and realized locational marginal prices. LSE demand has an impact on LMPs, and therefore an impact on the mix of units dispatched in the spot market, but LSEs are a price taker in this market. As a result, a carbon procurement adder would be applied to the mix of power in the spot market, without respect to individual generation sources, and therefore might not change the system mix.[51]

A carbon procurement adder would also not adequately address power purchase contracts where the source of the generation is not specified, but is instead left to the discretion of the supplier. These types of contracts guarantee the purchaser a set amount of firm energy and capacity, but leave it to the supplier to determine the mix of sources that will meet this demand. Suppliers may self-schedule generation they own, contract for power through another bilateral transaction, or purchase spot market power. It is unclear how a valid carbon adder could be applied to such transactions, since the CO_2 emission rate related to this power would be unknown at the time of the financial transaction. Determining the CO_2 emissions related to such transactions after the fact would also require significant forensic analysis of both market settlement systems and generation attribute tracking systems.

Theoretically, such a procurement adder might not impact system dispatch at all if the chosen “economic” resource, inclusive of carbon costs, remained the same as the resource chosen without the procurement adder. The dollar value of the carbon adder would therefore be a key variable that could affect the efficacy of this policy as a leakage mitigation strategy.

It should also be noted that in many instances this approach would only indirectly impact the dispatch of generators in the region. While LSEs might alter their purchasing decisions based on a carbon adder, generators would face no

[50] Note, by incorporating some of the environmental externalities (carbon costs) of wholesale spot market power, this would improve the relative economics of demand-side management options.
[51] Real-time evaluation of the emissions rate of spot market power is not currently possible. As a result, historic emissions averages would need to be applied.

direct compliance obligation or related cost adder. With the exception of a possible change in plant-specific bilateral power purchases by LSEs, a carbon procurement adder would not directly address the operation of generation units in the wholesale electricity market. Theoretically, it would, therefore, not preclude emissions leakage due to a re-dispatch of the regional power system due to a RGGI carbon cost adder.

Challenges and Implementation Issues

The carbon procurement adder is a planning tool designed for LSEs operating in a traditionally regulated – or as in California, re-regulated – environment, and is best suited to the evaluation of plant-specific power purchase agreements. In restructured states, such as the majority of RGGI participating states, implementation of a carbon procurement adder would likely require significant modifications to how LSE "providers of last resort" are required to procure electric generation supply. As an example, New Jersey currently requires LSEs to procure generation supply through an auction. Winning bids are typically not in the form of plant-specific bilateral contracts, but involve contractual guarantees over a limited multi-year period to deliver a specified amount of energy and capacity to an LSE. A carbon procurement adder would present a greater challenge to implement in such a context, absent significant modification to the procurement process.

Carbon Procurement Emissions Rate

Description and Implementation

A carbon procurement emissions rate is a limit that is placed on the emissions rate of power supplied to an LSE through a long-term power purchase agreement. This policy would require all long-term power purchases to meet a specific lbs. CO_2/MWh emission rate; power could not be supplied through bilateral contracts with power plants that exceed this emissions rate. California recently enacted a statutory requirement that new long-term power purchase agreements (five years or longer) may only be entered into if the power supplied through such a contract meets a CO_2 emissions rate equivalent to that of a natural gas combined cycle plant.[52]

Policy Strengths and Effectiveness

As an emissions leakage mitigation option, the emissions rate requirement would apply to all new long-term contracts both inside and outside the RGGI region. It could be applied based on the emissions rate for a certain class of technology, as was done in California, or based on the average emissions rate achieved by generation units within the RGGI region or a subset of the RGGI region. Both options would ensure that imported power was treated on an equivalent basis as power generated within the region.

By definition, this mechanism would not address the carbon intensity of power purchased through the spot market. As mentioned in the discussion of the carbon procurement adder, this mechanism would also not be practical in addressing power purchase agreements where the source of the power supplied is indeterminate at the time of the financial transaction.

Unlike an emissions portfolio standard, as discussed below, a carbon procurement emissions rate would address the bundled electricity commodity, rather than an unbundled emissions attribute. It would, therefore, directly impact the dispatch of power plants in the region, and could not be avoided through "attribute shuffling".[53]

Challenges and Implementation Issues

In restructured states, such as the majority of RGGI participating states, implementation of a carbon procurement adder would likely require significant modifications to how LSE "providers of last resort" are required to procure electric generation supply.

---

[52] See California Public Utilities Commission Decision 07-01-039, Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework Rulemaking 06-04-009 and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, January 25, 2007. Under this order, California adopted an "interim greenhouse gas (GHG) emissions performance standard for new long-term financial commitments to baseload generation undertaken by all load-serving entities (LSEs)," consistent with Senate Bill (SB) 1368 (Stats. 2006, ch. 598), intended to serve as "a near-term bridge" until an enforceable GHG emissions limit applicable to LSEs is established and in operation. SB 1368 establishes a minimum performance requirement for any long-term financial commitment for baseload generation that will be supplying power to California ratepayers. The new law establishes that the GHG emissions rates for these facilities must be no higher than the GHG emissions rate of a combined-cycle gas turbine (CCGT) power plant. Id. at 2.

[53] Attribute shuffling is examined in detail during the discussion of the emissions portfolio standard policy option. Note, this policy mechanism could possibly be subject to a related scenario, "contract shuffling", which is discussed at pp.40-41.

If long-term power purchase agreements were not mandated, the implementation of this policy could create a disincentive for entering into long-term power purchase agreements. As a result, implementation of this policy in the RGGI region would require a significant modification to how LSEs are required to procure generation supply.

<u>Emissions Portfolio Standard</u>

<u>Description and Implementation</u>

An emissions portfolio standard (EPS) is a policy mechanism that would require an LSE to meet an output-based emissions standard (lbs. CO_2/MWh) for the portfolio of electricity supply resources the LSE uses to provide retail electricity. This mechanism is indifferent to the source of electricity generation. Because it uses an average output-based standard, this mechanism could also be adapted to incorporate end-use energy efficiency along with supply-side resources as compliance measures. For instance, energy efficiency resources procured by a LSE could be credited with an emission rate of zero and considered as part of an LSE's overall supply resource when determining the average emissions rate for the total electricity supplied by the LSE.[54]

The implementation of an EPS in the RGGI states would cover all power that is used to serve retail demand in the RGGI region. The emissions rate could be set based on the historic emissions rate of generation used to serve load in the RGGI region, application of an emissions rate trend over time, or a technology-based standard. As an emissions leakage mitigation mechanism, an EPS would be most effective if it was implemented to compliment the RGGI generator-focused cap-and-trade program. Specifically, the established CO_2 emission rate could be equal to or indexed to the average emissions rate that is projected to be achieved by affected RGGI units or a regional subset of affected RGGI units.

An EPS would likely be implemented using an environmental attribute-based credit system that separates the generation attributes from the electricity commodity.

<u>Policy Strengths and Effectiveness</u>

An EPS would establish a market signal to LSEs and power generators that lower-emitting generation is a valuable commodity. An EPS would create a market value for the CO_2 emissions attributes of relatively low-emitting

[54] Theoretically, the ability to use emissions offsets could also be included, although Staff has not evaluated the policy case for including an offsets provision in such a policy. Emissions reductions achieved through offsets could be converted to an equivalent number of zero-emissions MWh certificates by dividing the number of offset tons by the emissions rate requirement under the EPS.

generation, and therefore could impact the market bids of generators and the dispatch of generation units. In certain instances, LSEs might also alter electricity purchasing decisions in response to the portfolio emissions rate requirement. However, with the exception of a possible change in plant-specific bilateral power purchases by LSEs, an EPS would not directly address the operation of generation units in the wholesale electricity market. It, therefore, would not preclude emissions leakage due to a re-dispatch of the regional power system due to a RGGI generation cost adder.

The market signal due the EPS would not necessarily fully address the cost differential between RGGI affected units and fossil fuel-fired units that are not subject to a carbon constraint.[55] Addressing the cost differential would depend on the relationship between the $/MWh compliance cost faced by the LSE to meet the emissions rate requirement relative to the $/MWh RGGI generation cost adder. As a result, while it would mitigate the market dynamics that could lead to emissions leakage, uncertainty would remain as to the efficacy level of this mechanism.

While an EPS would limit carbon intensity by holding an LSE to an average lbs. CO_2/MWh standard, the electricity demand within an LSE's service territory could continue to increase, which could allow for an increase in absolute emissions of carbon. This could potentially be addressed by modifying the CO_2 emissions rate over time, in order to limit total CO_2 emissions. For example, if electricity demand and absolute emissions continued to grow, the required CO_2 emissions rate could be reduced to ensure that projected demand (MWh) multiplied by emission rate (lbs. CO_2/MWh) equaled a specified number of tons of CO_2. However, such a mechanism would increase the complexity of implementing an emissions portfolio standard and could create market uncertainty for LSEs.

Challenges and Implementation Issues

A major implementation challenge would be how to address the potential for "attribute shuffling". As mentioned previously, an EPS would likely be implemented using an environmental attribute-based credit system that separates the generation attributes from the electricity commodity. This could be problematic in an "open" system that includes both regulated and unregulated regions. Such a compliance mechanism could potentially allow an LSE to purchase environmental attributes from low-emitting generation without changing its power procurement practices. In such as a scenario, an LSE could comply with the emissions standard requirement without impacting the dispatch of generation, and related emissions, in the region as a whole.

[55] Given the ability of LSEs to procure generation supply from a larger regional market than that covered under RGGI, and the ability to utilize demand-side resources, LSEs could potentially comply with the emissions rate requirement at a lower $/MWh cost than the $/MWh RGGI generation cost adder.

This dynamic points out the key difference between attribute credit systems used for determining compliance with renewable portfolio standards and the use of an attribute-based credit system used for determining compliance with an EPS. Renewable portfolio standards, with a few notable exceptions, typically require a very significant increase in installed renewable energy capacity and generation in order to meet the requirement. As a result, the system starts with a significant market shortfall of renewable energy attributes (renewable energy credits). This shortfall creates a significant attribute price that supports the construction of new renewable energy capacity.

This is likely not the case for an attribute credit-based EPS system implemented to address emissions leakage in the RGGI region, described as an "open" system. An "open" system addressing emissions leakage would be implemented in a broader market, in which the regulated region made up only a subset of that market. Such a system would likely have a surplus of low-emissions attribute credits, because generation in the broader market would exceed that needed to meet electricity load in the regulated region. As a result, LSEs in the regulated region could purchase "excess" low-emissions attributes without significantly impacting the dispatch (and emissions) of the larger power system. Under such a scenario, in an effort to evade the carbon price adder of RGGI-affected generation, LSEs would purchase presumed cheap low-emissions attributes while altering their power purchases to presumed higher emitting sources not subject to a carbon constraint. Due to the surplus of low-emissions attribute credits, the LSE $/MWh compliance cost would be lower than the $/MWh RGGI carbon compliance generation cost adder. This could allow for potential emissions leakage based on the continued LSE perception of a generation cost differential, even though the LSE is demonstrating compliance with the emissions portfolio standard.

This is distinct from a "closed" system where the full geographic region encompassing a control area is regulated under the system. In such a scenario, an emissions rate that was set at the historic level for that control area would not allow a re-dispatch of the system that resulted in a higher emissions rate, since there would be no "surplus" low-emissions attributes available to the regulated system.

Preventing attribute shuffling would require the modification of an attribute-based system, and would apply a hybrid approach that evaluated LSE "contract path" electricity transactions using ISO market settlement systems in combination with a generator attribute tracking system.[56] Specific emissions attributes would be applied to LSE transactions where a specific generation plant, and its related

[56] Note, such a system could still potentially be subject to a related dynamic, called "contract shuffling". Contract shuffling is discussed in the evaluation of a load-based carbon cap below at pp. 40-41.

emissions, could be identified.[57] With the exception of those MWhs for which a plant-specific emissions attribute is allowed, all other MWhs of LSE demand would be assigned a residual mix emissions attribute. This LSE-specific residual mix attribute would be the weighted average CO_2 emissions rate (lbs. CO_2/MWh) of all other generation serving load in the control area, after subtracting for the generation from those generation units for which LSEs in the regulated region are allowed to claim plant-specific emissions attributes.

Staff also notes that determining the appropriate emissions rate to apply could be a contentious process. Determining LSE-specific emissions rate baselines would follow a similar hybrid contract path and attribute tracking approach as that described previously for addressing the attribute shuffling issue. Determining individual historic LSE emissions rate baselines would be complex, as it would likely require forensic analysis of historic LSE contract path transactions and the use of generator attribute tracking systems to determine the emissions related to those purchases. As a result, the application of a regional emissions rate requirement would be simpler, but could meet with resistance from LSEs that could demonstrate current relatively low carbon portfolios.

3. Policies that Address and Cap Emissions

Load-Based Emissions Cap

Description and Implementation

A load-based emissions cap would place a cap on absolute CO_2 emissions related to all electricity use within a region.[58] The California Public Utilities Commission has implemented a rulemaking to develop a load-based cap.[59] This policy creates a requirement for an LSE to stabilize or lower the carbon content of its electricity supply portfolio, while also establishing an indirect

[57] This would apply to plant-specific bilateral power purchase agreements or the purchase of renewable energy attribute credits, which are not subject to attribute shuffling.

[58] Several load-based cap-and-trade policies have been proposed to Staff. One, in May 2004, was proposed as an alternative to the supply-side cap-and-trade program articulated in the RGGI model rule. This has been referred to as an "allocation-to-load" proposal. *See*, R. Cowart*, Another Option for Power Sector Carbon Cap-and-Trade System – Allocation-to-Load,* Regulatory Assistance Project, May 1, 2004. In the spring of 2006, a second, more narrowly-tailored, load-based proposal sought to augment the model rule and focused only upon imported power and associated emissions. Based upon discussions with expert panelists, Staff concluded that, for legal reasons, the proposal was problematic. *See* R. Cowart, *Addressing Leakage in a Cap-and-Trade System: Treating Imports as Sources, A Proposal and Notes for Discussion*, Regulatory Assistance Project, April 2006.

[59] On February 16, 2006, the California Public Utilities Commission issued D.06-02-032 in R.04-04-003. In that decision, the Commission stated its intent to develop a load-based greenhouse gas emissions cap as the cornerstone of its Procurement Incentive Framework, noting that: "[e]stablishing a GHG cap is consistent with the Governor's objectives for climate change policy, as well as our own GHG Policy Statement." D.06-02-032, mimeo., p. 16.

market signal to generators that low-emitting generation is a valuable commodity. A load-based cap could be set a number of ways, including:

- based on a stabilization of historic emissions related to electricity use within the LSE service territory
- based on the application of an emissions trajectory, beginning at a historic level of emissions related to electricity use within the LSE service territory
- based on an emissions rate (cap is equal to an emissions rate multiplied by a projected number of MWhs delivered by the LSE; assumed MWhs delivered could be capped)

Allowances would be allocated to individual LSEs, most likely based in some fashion on the emissions related to each LSE's historic electricity purchases. At the end of each compliance period, LSEs would have to submit allowances equivalent to the carbon emissions associated with the generation supply the LSE used to serve load in its service territory. LSEs would be able to reduce the carbon content of their portfolios by contracting with the providers of relatively low-emitting generation and reducing load in their service territories through energy efficiency and demand-side management. LSEs that reduced emissions below their allowance allocation would have allowances to sell; LSEs that failed to maintain emissions at their allowance allocation would need to purchase allowances from other LSEs that have excess allowances to sell.

The load-based cap mechanism provides for all market-based approaches available to LSEs to comply with the policy. LSEs could purchase low-emitting power on the wholesale market, invest in energy efficiency and other demand-side management resources, or purchase emissions allowances from other LSEs if it is more economic to do so. The ability to use emissions offsets could also be included in such a program, although Staff has not evaluated the policy case for including an offset provision.

Compliance with a load-based cap would be tracked in a similar fashion as an EPS, using a hybrid of ISO market settlement systems and generator attribute tracking systems. Specific emissions attributes would be applied to LSE transactions where a specific generation plant, and its related emissions, could be identified (plant-specific bilateral electricity purchases and renewable energy attribute credits).[60] With the exception of those MWhs for which a plant-specific emissions attribute is allowed, all other MWhs of LSE demand would be assigned a residual mix emissions attribute. This LSE-specific residual mix attribute would be the CO_2 emissions rate for all other generation units in the control area, after subtracting for the generation from those generation units for which LSEs in the regulated region are allowed to claim plant-specific emissions attributes.

[60] The use of RECs would be allowed, since attribute shuffling is not a serious concern with regard to renewable energy. See discussion of attribute shuffling at pp. 37-38.

Policy Strengths and Effectiveness

If properly designed, a load-based cap should be effective in addressing the majority of any potential emissions leakage, although it may present potential limitations. A load-based cap could be subject to a dynamic similar to attribute shuffling, called "contract shuffling":

> A rule that assigns carbon attributes solely on the basis of power units assigned to a sale in a bilateral contract risks under counting the actual carbon contribution associated with the purchase in question. This is because it would be advantageous to sellers to contractually assign clean power to export sales into the RGGI region, while increasing carbon-intensive power assigned to non-RGGI sales, without necessarily improving the generator's emission profile at all.[61]

Without all electricity sales being subject to a load-based cap, it is possible for buyers and sellers to "shuffle" contracts in this manner. Under such a scenario an LSE could potentially comply with a load-based cap without impacting the emissions profile of the regional power system. Staff notes that this approach would involve more complex transactions among parties than attribute shuffling, since it involves the trading of electricity. As a result, this approach would involve scheduling of generation and transmission, and could be constrained by transmission capability and transmission costs.

Any remaining emissions leakage would likely be due to limitations in the precision of an emissions tracking system for a load-based cap, which would rely in part on average emissions proxies for certain categories of power purchases.

It should also be noted that like an EPS, a load-based cap would only indirectly impact the real-time dispatch of generators in the region, since generators would face no direct compliance obligation and related cost adder due to the EPS. As a result a load-based cap would not preclude emissions leakage resulting from a real-time re-dispatch of the regional power system due to a RGGI generation cost adder. However, LSEs would be subject to a compliance obligation related to the carbon-intensity of spot market power. If the carbon intensity were high, this would provide a disincentive for LSE reliance on spot market power and/or an incentive for more aggressive demand-side measures to avoid the need for spot market purchases. As a result, countervailing market forces would be expected to mitigate such an outcome over the long-term. Since LSEs would have a fixed carbon compliance obligation, any near-term emissions leakage due to a real-time re-dispatch of the power

[61] Cowart, *Addressing Leakage in a Cap-and-Trade System*, p. 6.

system due to a RGGI cost adder would be counterbalanced by additional low-carbon power purchases by the LSE or LSE electricity demand reductions.[62]

Challenges and Implementation Issues

While staff views a load-based cap as a viable leakage mitigation mechanism, its implementation comes with significant challenges. Under this proposal, an emissions allocation for each LSE would need to be established. This would require the establishment of emissions estimates related to historical electricity purchases by each LSE over a multi-year period.[63] Unlike a process for estimating regional emissions leakage, establishing LSE baselines for a load-based cap-and-trade system would require detailed analysis of historic LSE bilateral power purchases and spot market purchases, and an estimate of the emissions related to those purchases. This would require the use of both generator attribute tracking systems and ISO market settlement systems to evaluate the contract path of LSE electricity purchases. As a result, it would present significant additional requirements beyond those that would be required to track regional emissions leakage through a generator attribute tracking system.

Staff also notes that some proponents of the implementation of a load-based cap in the RGGI region have argued that such a policy should be implemented so as to allow for allowance trading between a load-based cap-and-trade system and a generator-based cap-and-trade system. This would allow generators and LSEs to trade their respective allowances with each other, making allowances in the load-based and generator-based systems fully fungible.

Staff recommends that if a load-based cap is considered, it should be implemented in parallel to the RGGI generator-focused cap-and-trade system, and trading should not be considered between such systems, at least initially. Staff notes that the estimation of emissions attributable to electricity use is subject to significantly more uncertainty than the monitoring and reporting of emissions in a generator-based cap-and-trade system.

V. Impact of Emissions Leakage Mitigation Policies on Electric System Reliability

In the RGGI MOU, signatories states agreed that in considering options for addressing potential emissions leakage, Staff should consider the potential

[62] It should be noted that in PJM not all LSEs would be subject to a load-based cap. A load-based cap applied to a subset of the LSEs in a control area would therefore not preclude a long-term re-dispatch of the power system in response to a RGGI generation cost adder.

[63] This would likely be required even if an emissions rate-based cap was used. Some LSEs would claim that their supply portfolios are less carbon intensive than other LSEs, and would likely advocate for an estimation of the relative carbon intensiveness of each LSEs historic portfolio as a means of allocating the regional cap to individual LSEs.

impacts that policies may have on electric system reliability.[64] For the reasons explained below, the adoption of any of the policy options being considered in this report should have no significant effect on electric system reliability.

Staff concludes that all three categories of proposed leakage mitigation policy responses would have no effect upon electricity system reliability. All of the policies considered in this report place no direct compliance obligation, and related cost adder, on electric generation units. Policies evaluated would either impact electric demand or place specific carbon requirements on LSEs. These policies would be expected to impact the purchasing decision of LSEs with regard to electric generation supply, but would not directly impact the economics of individual electric generators.

Even policies that place a modest compliance obligation on generation units are not expected to impact system reliability. In a market where generators are required to purchase emissions allowances, the associated costs are included in bid prices and those plants would, therefore, be dispatched on the basis of their direct costs plus their allowance costs. Therefore, the market clearing price can be expected to be increased by the cost of allowances associated with operating the marginal plant in each hour, and this cost can be expected to be passed on to the LSEs.

In extreme cases, ensuring system reliability can be understood as an exception to the least-cost economic dispatch model. Generator costs are included in the bid prices that generators submit to their ISO, and generation units are then dispatched on their relative economic merits: the cheapest units are dispatched first; then more expensive ones follow. However, system reliability is ensured by allowing units that are required for reliability purposes to be dispatched out of economic merit order. While these units may be more expensive than ones that would be dispatched on a solely economic basis, they are directed to operate to maintain system reliability. In essence, reliability "trumps" economic dispatch given the physical constraints of the transmission system.

In addition, none of the policies affects the manner in which ISOs currently ensure system reliability. In contrast, policies that create additional incentives for end-use energy efficiency and demand side management will provide system reliability benefits. All of the policies considered in this report would or could provide incentives for end-use energy efficiency and demand-side management.

Energy policies that promote cost-effective energy efficiency, demand-side management, and more efficient and cleaner electric generation have been in effect for nearly two decades and have had no harmful impacts on the ability of

---

[64] MOU at section 6(A)(1)(a). Section 6(B) also contains a commitment to monitor the program to ensure on an ongoing basis "that the Program will not result in electricity supply interruptions."

the ISO to maintain system reliability.[65] Similarly, the energy efficiency-related policies discussed in this report should not adversely affect generation dispatch or system reliability.

A carbon procurement adder, carbon procurement emissions rate, emissions portfolio standard, and a load-based cap would all encourage LSEs to purchase electricity that is relatively cleaner than the system mix. All of these policies would require an LSE to plan for future purchases in a manner that recognizes the carbon emissions associated with the purchase of electricity generated from fossil fuel-fired sources and, if designed properly, could provide incentives for the purchase of demand-side resources. In all cases, the wholesale market for cleaner generation and demand-side resources would be stimulated.

None of these policies would result in any limitation on ISO management of generation dispatch for reliability purposes. In addition, none of these policies would place any direct compliance obligation or generation cost adder on any generation unit. System reliability is an ISO management function that allows for an override of the market dispatch rules in order to ensure that generation required for reliability purposes runs regardless of that generation's relative economic merit. None of the various leakage policies considered here would have the effect of limiting an ISO's ability to dispatch generation – regardless of the type – for purposes of ensuring system reliability. Nor would any of these policies be expected to constrain the real-time dispatch of any generation unit.

[65] Some of these policies are funded through electricity rates, or explicitly through a system benefit charge (SBC).

References

Aulisi, et al., *Greenhouse Gas Emissions Trading in the U.S. States: Observations and Lessons from the OTC NO_x Budget Program*, World Resources Institute 2005.

Center for Integrative Environmental Research, University of Maryland, College Park, *Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative*, January 2007.

Cowart, Richard, "Addressing Leakage in a Cap and Trade System: Treating Imports as Sources – proposal and notes for discussion," Regulatory Assistance Project, April 2006.

Cowart, Richard, "Another Option for Power Sector Carbon Cap and Trade System – Allocation to Load," Regulatory Assistance Project, May 1, 2004.

Davis, Stacey, *Design of a Cap on Emissions from California Power Demand*, Center for Clean Air Policy, October 14, 2005.

Generation Attribute Tracking System (GATS) Operating Rules, Revision 4, May 10, 2006.

Hoffman, A., *Getting Ahead of the Curve: Corporate Strategies that Address Climate Change*, Pew Center on Global Climate Change, October 2006.

ICF Consulting, "RGGI Electricity Sector Modeling Results: Updated Reference, RGGI Package and Sensitivities," September 21, 2005.

ICF Consulting, Updated Reference and Sensitivities, September 8, 2005,

Nadel, et al., *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards*, ACEEE Report Number A051 and ASAP Report Number 5, 2005.

National Council on Competition and the Electric Industry, *Full Environmental Disclosure – Tracking and Reporting Key Information*, 1997.

New England Power Pool Generation Information System Operating Rules, updated January 2007.

New York State Department of Public Service, *Staff Report on the State of Competitive Energy Markets: Progress to Date and Future Opportunities*, March, 2006.

References (Cont'd)

Northeast Energy Efficiency Partnership, Inc., *Economically Achievable Energy Efficiency Potential in New England*, November 2004 (Updated May 2005).

Ozone Transport Commission, *NO_x Budget Program 1999-2002: Progress Report*, 2003.

PJM, 2005 *State of the Market Report*, 2006.

PJM, *Locational Marginal Pricing*, LMP-101 Training Materials, March 6, 2006.

PJM, Overview of Market Settlements, Transactions 201 Training Materials, February 24, 2005.

PJM, "PJM Market Simulation: Analysis of Possible Affect of Neptune Project on PJM Wholesale Electricity Prices," 2005.

Prindle, et al., *Energy Efficiency's Next Generation: Innovation at the State Level*, American Council for an Energy-Efficient Economy, ACEEE Report Number EO31, November 2003.

RGGI, *Regional Greenhouse Gas Initiative Memorandum of Understanding*, December 20, 2005.

RGGI, "Emissions Leakage Working Group Work Plan," June 14, 2006.

U.S. Environmental Protection Agency, *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States*, April 2006.

Wilson et al., *The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative*, Resources for the Future Discussion Paper RFF DP 05-37, August 2005.

Appendix I—A

New England ISO Generator Information System Data and Reports

GIS Rule 5.3 Reports for Regulatory Agencies and System Operator

(a) Each of the regulatory agencies listed on Appendix 5.3 (the "Regulators") and the System Operator shall have access, via a secure, password restricted internet portal, to quarterly and annual reports generated by the GIS Administrator. Quarterly reports shall be provided by the 5th day after the close of a Trading Period and shall relate solely to such Trading Period; and annual reports shall be produced by July 1 of the year following the year to which the report applies. Annual reports shall include amounts for the generation occurring and Certificates Obligations arising during the applicable calendar year and shall include Certificates transactions that occurred during the portions of the Trading Periods that occurred following the end of such calendar year.

(b) Each report provided to the Regulators and the System Operator shall include the following information:

(i) List of GIS Generators identified by name, date commercial operations were commenced and date of any repowering and/or capacity addition, categorized by fuel source;

(ii) List of Retail LSEs with GIS accounts, identified by name and categorized by state(s) for which they hold sub-accounts;

(iii) Total MWh of Energy generated in the Control Area during the reporting period;

(iv) Total MWh of Energy imported into the Control Area during the reporting period;

(v) Total number of Certificates created during the reporting period;

(vi) Allocation of Certificates among retail load in each state during the reporting period, categorized by fuel source;

(vii) Total number of Renewable Certificates created during the reporting period;

(viii) Total number of Banked Certificates at the end of the reporting period;

(ix) Total number of Banked Certificates from prior Trading Periods that were used to satisfy a Certificates Obligation, used for an export transaction or used in a Reserved Certificate transaction in the Trading Period that most recently ended;

Appendix I—A (Cont'd)

(x) Total Unsettled Certificates retired at end of Trading Period, by fuel source and with average emissions;

(xi) Average, in pounds, of each of the emissions listed in Appendix 2.4 that is attributable to load in each state as a result of the Certificate allocation during the reporting period;

(xii) For each GIS Generator, the pounds of each of the emissions listed in Appendix 2.4 for such reporting period;

(xiii) List of GIS Generators and Importing Account Holders reporting emissions by specific fuel type for multi-fuel generating units pursuant to Rule 2.5(d);

(xiv) Total MWh of Energy exported from the Control Area during the reporting period;

(xv) Total number of Reserved Certificate transactions for the reporting period, together with the Account Holder transferring each such Reserved Certificate and the transferee of each Certificate or Forward Certificate subject to such a Reserved Certificate transaction;

(xvi) a list of all Certificates designated as Reserved Certificates at the end of the reporting period together with access via the internet portal to such Certificates; and

(xvii) a description of the Residual Mix Certificates during the reporting period, with and without giving effect to the Reserved Certificate transactions during that reporting period.

(c) Notwithstanding the availability of such reports to the Regulators, each entity subject to any Attribute Law is responsible for demonstrating compliance with that Attribute Law, and neither the GIS Administrator nor NEPOOL nor the System Operator nor the NEPOOL GIS Project Manager has any responsibility for ensuring an entity's demonstration of Attribute Law compliance.

APPENDIX I—B

PJM Generator Attribute System Data and Reports

Appendix F to GATS Operating Rules contains a list of the following reports for regulators:

- GATS Generators (general information report on all GATS generators)
- Import Generators (general information report on all registered Import generators)
- Retail LSEs with GATS Sub-accounts in PJM States (report of all registered LSE's and where they have registered sub-accounts)
- Settled Certificates by LSE and State (report on settled certificates, listed by LSE and by state)
- Emission Defaults for each Fuel Type (report on default emissions levels for all fuel types)
- Total Certificates Allocated to Load by State (report on certificate allocation to load, by state and fuel percentage)
- Certificates Allocated to Load by State (report on certificate allocation to load, by state, and by Generating Unit)
- Quarterly Energy Summary (general information report on energy data in GATS – generation, imports, exports, etc)
- Annual Energy Summary (general information report on energy data in GATS – generation, imports, exports, etc.)
- Quarterly Total Emissions by GATS Generator (report on emissions by generator)
- Annual Total Emissions by GATS Generator (report on emissions by generator)
- Units Reporting Emissions via an Approved Emissions Protocol (report on all generating units that follow the approved emissions protocol)
- Reserved Certificate Transactions (general report on all reserved certificate transactions for a given trading period)
- Certificate Statistics (report on all certificate attributes, fuel types, locations, etc.)
- Residual Mix including Reserved Certificates (report on quantity of residual mix certificates, including reserved certificate statistics)
- PJM Residual Mix (detailed report on all PJM residual mix certificates)
- PJM System Mix (detailed report on the number of certificates created for PJM resources, by fuel type)
- Quarterly State Emissions by Sub-account and Averaged per Certificate (state-by-state count of certificates and averaged emissions)
- Annual State Emissions by Sub-account and Averaged per Certificate (state-by-state count of certificates and averaged)
- Clean Energy Portfolio Standard (CEPS) Certificates (summary report on all CEPS certificates)
- Reserved Certificates (Summary report on all Reserved Certificates)

APPENDIX II

Development of New York Generator Attribute Tracking System

New York's Case 03-E-0188

In accounting for and tracking electricity transactions, the PJM and the New England tracking systems separate the commodity (electrons) from the associated environmental attributes of the underlying generation. This is significantly different than the current New York Environmental Disclosure Program, which does not separate electricity from its underlying generation attributes. However, New York is considering the development of a system similar to those being used in New England and PJM.[1]

In its June Order, the New York Public Service Commission (PSC) recognized that, if a "certificate-based tracking system is developed, then the title to the environmental attributes could be in the form of renewable energy certificates (RECs), which would be easily transferred to [New York State Energy Research and Development Authority] NYSERDA as proof of its acquisition of renewable attributes."[2] The PSC indicated that "Department of Public Service Staff advises that a review of the New England disclosure system suggests that New York's Environmental Disclosure Program can be successfully modified to accommodate the new policies."[3] The New York PSC also noted that "NYSERDA and Staff will issue a request for proposals for development of a tracking system."[4]

[1] *See* Case 03-E-0188 Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, Order of June 28, 2006 ("June Order") at 3.
[2] *Id.* at 6.
[3] *Id.*
[4] *Id.* at note 8.

Appendix III

Legal Issues

Introduction

Legal scholars at the Imports and Leakage Workshop at Vermont Law School in June 2006, argued that the design of various proposals to address emissions leakage could potentially raise issues of federal law. The discussion below reviews many of the points made in their presentations. It focuses primarily on two key issues: (1) preemption by federal law; and (2) the dormant commerce clause.

This is not a comprehensive analysis of all potential legal issues involving implementation of measures to address potential emissions leakage. That is beyond the scope of this report. Instead, the policies considered here are general proposals, and the observations made are also general in nature and are designed to stimulate discussion.

Preemption Fundamentals

The "Supremacy Clause" of Article VI of the U.S. Constitution[1] provides Congress with the power to pre-empt state law. In Louisiana Public Service Commission v. F.C.C., the U.S. Supreme Court wrote:

> Pre-emption occurs when Congress, in enacting a federal statute, expresses a clear intent to pre-empt state law, when there is outright or actual conflict between federal and state law, where compliance with both federal and state law is in effect physically impossible, where there is implicit in federal law a barrier to state regulation, where Congress has legislated comprehensively, thus occupying an entire field of regulation and leaving no room for the States to supplement federal law, or where the state law stands as an obstacle to the accomplishment and execution of the full objectives of Congress. Pre-emption may result not only from action taken by Congress itself; a federal agency acting within the scope of its congressionally delegated authority may pre-empt state regulation.[2]

Likewise, in Crosby v. National Foreign Trade Council,[3] the Supreme Court wrote that a "fundamental principle of the Constitution is that Congress has the power

---

1 "This Constitution, and the Laws of the United States which shall be made in Pursuance thereof; and all Treaties made, or which shall be made, under the authority of the United States, shall be the supreme Law of the Land; and the Judges in every State shall be bound thereby, any Thing in the Constitution or Laws of any State to the Contrary notwithstanding." U.S.C.A. Const. Art. VI, cl. 2.

2 Louisiana Public Service Commission v. F.C.C., 476 U.S. 355, 368-69 (1986).

3 Crosby v National Foreign Trade Council, 530 U.S. 363, 363 (2000).

to preempt state law."[4] Preemption is typically understood as being of three types. "Express preemption" occurs where a statute explicitly states that it is federal law that controls and that state law is superceded.[5] "Conflict preemption" occurs in a case where "compliance with both state and federal law is impossible, or when the state law stands as an obstacle to the accomplishment and execution of the full purposes and objective of Congress."[6] "Field preemption" occurs "where compliance with both federal and state law is in effect physically impossible." It should be recognized that courts have recognized that "the categories of preemption are not rigidly distinct" and that, for example, "field pre-emption may be understood as a species of conflict pre-emption."[7]

Preemption Implications

Arguably, a state-based program that regulates the carbon emissions of electric generators or the generation portfolios of LSEs might be subject to a claim of preemption under the Clean Air Act or the Federal Power Act. To date, however, the U.S. Environmental Protection Agency (EPA) has not regulated carbon from electric generators. The CAA also provides states with significant flexibility to regulate emissions to a greater extent in certain areas than the Act itself requires.[8]

---

4 Id.

5 *See, e.g.*, Rush Prudential HMO, Inc. v. Moran, 536 U.S. 355, 364 (2002), "[t]o 'safeguar[d] the establishment, operation, and administration' of employee benefit plans, ERISA sets 'minimum standards assuring the equitable character of such plans and their financial soundness,' 29 U.S.C. § 1001(a), and contains an express preemption provision that ERISA 'shall supersede any and all State laws insofar as they may now or hereafter relate to any employee benefit plan' ...."

6 U.S. v. Locke, 529 U.S. 89, 109 (2000), citing to City of New York v. FCC, 486 U.S. 57, (1988) ("'[A] federal agency acting within the scope of its congressionally delegated authority may pre-empt state regulation' and hence render unenforceable state or local laws that are otherwise not inconsistent with federal law").

7 Crosby v. Nat'l Foreign Trade Council, 530 U.S. 363, 373 (2000); *see also* Caleb Nelson, Preemption, 86 Va. L.Rev. 225, 262 (2000).

8 See CAA § 116.

> Except as otherwise provided in sections 119 (c), (e), and (f)(as in effect before the date of the enactment of the Clean Air Act Amendments of 1977), 209, 211(c)(4), and 233 (preempting certain State regulation of moving sources) nothing in this Act shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution; except that if an emission standard or limitation is in effect under an applicable implementation plan or under section 111 or 112, such State or political subdivision may not adopt or enforce any emission standard or limitation which is less stringent than the standard or limitation under such plan or section.

42 U.S.C. 7416.

Appendix III (Cont'd)

None of the proposals reviewed here call for any changes to wholesale power contracts or transmission tariffs, which are subject to FERC authority under the Federal Power Act.[9] The proposals focus upon retail LSEs whose activities are generally considered state jurisdictional.

There has been federal legislation that preempts some state appliance and equipment energy efficiency standards. With the passage of the Energy Policy Act of 2005,[10] the federal government has preempted over a dozen categories of state appliance and equipment energy efficiency standards. Under the general rules of federal preemption in that bill, states which had set standards prior to federal enactment may enforce their state standards up until the various effective dates of the federal standards. States that have not yet established standards, or whose standards have yet to be implemented, are preempted immediately.

The Department of Energy (DOE), however, can grant waivers of preemption for particular State laws or regulations.[11] For example, on October 6, 2006, DOE issued a Notice of Proposed Rulemaking (NOPR) in which DOE proposes to amend energy conservation standards for residential furnaces and boilers. DOE indicated the following in the NOPR:

> States with a regulation that provides for an energy conservation standard for any type of covered product for which there is a Federal energy conservation standard may petition the Secretary for a DOE rule that allows the State regulation to become effective with respect to such covered product.[12]

Staff should review the status of the implementation of appliance and equipment energy efficiency standards in their respective states. Furthermore,

---

9 According to the Federal Power Act, the Federal Energy Regulatory Commission (FERC) approves contracts and tariffs that set the price of electricity. The FERC regulates most transmission, wholesale transactions in electricity, and sets wholesale rates. States, on the other hand, regulate intrastate retail electricity rates: "the regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States . . . ." Arkansas Elec. Co-op. Corp. v. Arkansas Public Service Com'n, 461 U.S. 375 (1983). However, a "State must give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority." Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953, 966 (1986).

10 Pub. L. 104-58 ("EPACT 2005"). EPACT 2005 amended the Energy Policy and Conservation Act (EPCA). Part B of title III of EPCA (42 U.S.C. 6291-6309) provides for the Energy Conservation Program for consumer Products other than Automobiles, and establishes minimum standards of energy efficiency for many major appliances.

11 In accordance with the procedures and other provisions of section 327(d) of the EPCA located at 42 U.S.C. 6297(d).

12 *See* Federal Register /Vol. 71, No. 194 / Friday, October 6, 2006 / Proposed Rules 59205.

Staff should determine the degree to which their particular standards have been or may be preempted.

Commerce Clause Fundamentals[13]

Historically, the protection of a state's environment, public health, and safety has been considered a legitimate exercise of state power.[14] Provided a state "does not needlessly obstruct interstate trade or attempt to place itself in a position of economic isolation, it retains broad regulatory authority to protect the health and safety of its citizens, and integrity of its natural resources."[15]

States cannot purposely discriminate against interstate commerce,[16] and when a state statute does so, "it will be struck down unless the discrimination is demonstrably justified by a valid factor unrelated to economic protectionism."[17] In this context the term "discrimination" means the differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter.[18]

State regulations that do not discriminate against interstate commerce, but which nonetheless place a burden on interstate commerce, are subject to a legal balancing test. Specifically:

> Where a state regulates evenhandedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits.[19]

Where a court determines that a statute or regulation burdens interstate commerce, the court must determine whether the burden imposed is incidental or

[13] The U.S. Constitution provides that the "Congress shall have power … to regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes...." U.S.C.A. Const. Art. I, § 8, cl. 3.

[14] Huron Portland Cement Co. V. Detroit, 362 U.S. 440, 443 (1960).

[15] Maine v. Taylor, 477 U.S. 131, 151 (1986).

[16] Welton v. Missouri, 91 U.S. (1 Otto) 275 (1876).

[17] Wyoming v. Oklahoma, 502 U.S. 437, 454-55 (1992). Where "simple economic protectionism is effected by state legislation, a virtually per se rule of invalidity has been erected . . . ." National Solid Wastes Management Ass'n v. Alabama Dep't of Envtl. Management, 910 F.2d 713, 718-21 (11th Cir. 1990); City of Philadelphia v. New Jersey, 437 U.S. 617 (1978). There can be "no patent discrimination against interstate trade." Id. State regulations may not benefit in-state economic interests by burdening out-of-state competitors in a discriminatory fashion. Wyoming, 502 U.S. 454-55 (1992).

[18] See presentation of F. Zalcman, citing to City of Philadelphia v. New Jersey, 437 U.S. 617 (1978).

[19] Pike v Bruce Church, 397 U.S. 137 (1970).

facial. Then the court must determine whether there are mitigating factors that might justify imposing that burden. The analysis of incidental and facial burdens involves different tests to determine whether the statute or regulations causing the burdens are constitutionally valid.

Incidental Discrimination

In Pike v. Bruce Church, Inc.,[20] the Supreme Court articulated the test for what are known as "incidental" impacts on interstate commerce. It wrote:

> [w]here the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits."[21]

This test calls for a finding of "legitimate local purpose" and then balances that purpose with the burden on interstate trade. Also, the test requires a determination as to whether the purpose could be realized through some less burdensome means.[22]

An analysis for incidental discrimination is found in Minnesota v. Clover Leaf Creamery Co.,[23] a case in which the Supreme Court upheld an environmental statute, and found that the burden on interstate commerce was outweighed by the environmental benefit to the state. In Clover Leaf the State of Minnesota had banned the retail sale of milk in plastic nonreturnable, nonrefillable containers, and out-of-state milk suppliers challenged the statute. In its review of the Minnesota regulation, the Court found that the burden on interstate commerce would be relatively minor. The Court concluded that Minnesota suppliers were not necessarily benefitting at the expense of out-of-state suppliers.[24] In balancing the two, the Court also determined that, although there was an incidental burden, it was not "clearly excessive" in light of the substantial state interest in promoting conservation of energy and other natural resources…."[25] The Court also determined that there was no alternative that would be less discriminatory.[26]

---

[20] Id.
[21] Id. at 142.
[22] The expression, "incidental burdens" was defined in Automated Salvage Transp., Inc. v. Wheelabrator Envtl. Sys. Inc., as "the burdens on interstate commerce that exceed the burdens on intrastate commerce." Automated Salvage Transp., Inc. v. Wheelabrator Envtl. Sys., Inc., 155 F.3d 59, 75 (2d Cir. 1998).
[23] Minnesota v. Clover Leaf Creamery Co., 449 U.S. 456 (1981).
[24] Id at 472.
[25] Id at 473.
[26] Id.

Facial Discrimination

Maine v. Taylor[27] articulates the Supreme Court's analysis for what is referred to as "facial," *i.e*., explicit discrimination. Under this test, a "statute must serve a legitimate local purpose, and the purpose must be one that cannot be served as well by available nondiscriminatory means."[28] In cases of facial discrimination, the Supreme Court has applied its test with what it calls "strict scrutiny." In Hughes v. Oklahoma, the Court wrote: "facial discrimination invokes the strictest scrutiny of any purported legitimate local purpose and of the absence of nondiscriminatory alternatives."[29]

Despite applying strict scrutiny to facially discriminatory statutes, under certain circumstances the Supreme Court has upheld such a statute.[30] The rare example of this is found in Maine v. Taylor,[31] a case in which the Court upheld a ban by the State of Maine on out-of-state baitfish due to a determination that harmful parasites were found in imported baitfish. The purpose of the ban was to protect in-state baitfish from disease that appeared to be related to the importation of the out-of-state fish. The Court wrote that a state has "broad authority to protect the health and safety of its citizens and the integrity of its natural resources . . . ."[32] The court also recognizes that states have a "legitimate interest in guarding against imperfectly understood environmental risks."[33]

Commerce Clause Implications

In reviewing the implications of the three categories of proposed emissions leakage mitigation policies for purposes of a commerce clause challenge, presenters concluded that – with appropriate care for a design that is evenhanded and avoids geographic discrimination – each of the proposed policy approaches should be able to withstand a commerce clause challenge.

Policies that Reduce Electricity Demand

The term "complementary energy policies" refers to a varied group of mechanisms currently being implemented state-by-state across the RGGI region.

[27] Maine v. Taylor, 477 U.S. 131 (1986).
[28] Id . at 140.
[29] Hughes v. Oklahoma, 441 U.S. 332, 337 (1979).
[30] In spite of its ruling in Maine v. Taylor, it is far more common for the Supreme Court to strike down facially discriminatory laws. See e.g., Camps Newfound/Owatonna, Inc. v. Town of Harrison, 520 U.S. 564, 574-76 (1997).
[31] Maine v Taylor, 477 U.S. 131 (1986).
[32] Id. at 151.
[33] Id.

Some of these policies are funded out of electricity rates, implicitly or explicitly through a system benefit charge (SBC).[34]

The increased use of complementary energy policies to reduce emissions leakage is unlikely to draw a commerce clause challenge. As noted, these policies are currently being used in many states. To the extent they have not been challenged to date, it is not clear why their increased funding would now subject them to a challenge. The Supreme Court has also stated that subsidies to in-state industry do not contravene the commerce clause.[35] Thus, a state's implementation of complementary energy policies, even if subsidized, does not contravene the commerce clause. However, such policies should be administered in a neutral fashion, *i.e.*, in a manner that does not exclude a possible player for geographic reasons. If a program were to discriminate, even if the program were funded in a neutral manner, the program could be challenged.[36]

Carbon Emission Performance Standard

To reduce emissions leakage, RGGI states could adopt an emissions portfolio standard for all power sold in-state or, for planning purposes, a carbon adder for all power procurement. Where they do not target in- or out-of-state power sales differentially, these policies would be facially neutral, and should not contravene the commerce clause. These are also policies that would be justifiable in that they do not seek to regulate beyond the RGGI region, but instead – like an RPS or other portfolio standard – seek to ensure that in-region purchases of electricity conform to a certain standard.

---

[34] A line-item included in retail electric bills that represents public benefits implicit in electricity rates prior to electric industry restructuring, which have been explicitly made part of retail electric rates.

[35] See West Lynn Creamery, Inc. v. Healy, 512 U.S. 186, 193 (1994) "A pure subsidy funded out of general revenue ordinarily imposes no burden on interstate commerce, but merely assists local business." Id.

[36] For example in West Lynn, the Supreme Court considered the constitutionality of a Massachusetts statute that imposed two commonly used financing mechanisms: a nondiscriminatory tax and a subsidy. The challenge succeeded because the Court determined that the mechanisms were used in tandem in such a way that discriminated against out-of-state milk suppliers. The State of Massachusetts imposed a non-discriminatory tax on Massachusetts and other milk dealers operating in state. The tax did not distinguish between in-state and out-of-state milk dealers. However, the statute provided for a subsidy to only Massachusetts milk dealers. The Court concluded that this subsidy negated the first mechanism, the neutral tax, and on that basis ruled that the program was unconstitutional. For further discussion *see* Engel, *The Dormant Commerce Clause Threat to Market-Based Environmental Regulation: the Case of Electricity Deregulation*, 26 Ecology L.Q. 243 (1999).

Appendix III (Cont'd)

Load-Based Emissions Cap

A policy that requires a LSE to submit allowances for the carbon content of all of its electricity supply regardless of the geographic source of the supply would be likely to withstand a commerce clause challenge. As explained in the discussion below, a successful policy should be facially neutral.

Facial Discrimination

A policy that focuses solely on electricity imports, and thus differentiates among affected entities on the basis of location, would be considered facially discriminatory. Such a program would likely be treated as per se invalid, and a court's analysis would focus upon whether the states actually have an interest in climate change, and whether there exist less discriminatory means to reach the same results. For a state to establish its interest in climate change would not be difficult. However, a challenger could readily show that there are less-discriminatory means of achieving the same results.

Facial Neutrality

A policy that is found to be facially neutral has a greater likelihood of surviving a challenge. An emissions leakage mitigation policy that imposes the same performance requirements on power generated both in-state and out-of-state would meet this requirement.

If the policy were facially neutral, it would still be required to meet the Pike test. In this case, the question would be whether the state's interest in reducing carbon associated with electricity usage justifies the discriminatory effect resulting from the implementation of the policy. Justifying this would require a demonstration by the state that these measures are necessary to protect the state's environment. The Supreme Court has indicated that nondiscriminatory burdens upon interstate commerce imposed to protect the state's own environment will be given some measure of deference.[37]

Arguably, the implementation of a facially neutral LSE policy would result in a program similar to the program reviewed and upheld in Clover Leaf. Under

[37] See, e.g., Minnesota v. Clover Leaf Creamery Co., 449 U.S. 456, 473 (1981) (upholding state ban upon the sale of milk in plastic containers based upon state's purpose of reducing solid waste despite fact that ban would result in diverting business from out-of-state plastic container manufacturers to in-state pulp-based cardboard manufacturers).

this policy, RGGI states could require the purchase of electricity to be accompanied with certificates or allowances that reflect the attributes of all power purchased. Like the Minnesota container policy, there would be significant environmental reasons for the LSE policy. Also the policy does not distinguish between in- and out-of-state generation. Here there would also be a relatively minor burden on interstate commerce because no requirements would be placed on out-of-region electric generators. In-region LSEs would need to retire certificates or allowances that match the carbon content of their electricity purchases. While some of the certificates or allowances would come at a cost, the policy would not necessarily benefit in-region LSEs or generators at the expense of out-of-state generators. It would also be difficult to demonstrate that the burden imposed on commerce is "clearly excessive in relation to the putative local benefits," as required under Pike. It is difficult to think of a less discriminatory alternative since LSEs are precisely the primary market participants that would be causing any potential emissions leakage to occur. It is the demand of LSE customers for electricity that is causing additional electricity to be generated, and carbon dioxide to be emitted.

Appendix IV

Status of Residential and Commercial State Building Energy Codes and Equipment Energy Efficiency Standards for the RGGI Region

Table 1. Residential Building Energy Codes

	Residential Code	***Enforcement Status***	***Approximate Stringency***	***Residential Code Notes***
Connecticut	2003 IECC	Mandatory Without Amendments	As stringent as the 2003 IECC	
Delaware	2000 IECC	Mandatory Without Amendments		
Massachusetts	State Specific Code	Mandatory With Amendments	More stringent than the 95 MEC	1995 MEC with amendments
Maryland	2003 IECC	Mandatory Without Amendments	As stringent as the 2003 IECC	
Maine	2003 IECC	Mandatory With Amendments	As stringent as the 2003 IECC	
New Hampshire	2000 IECC	Mandatory With Amendments	As stringent as the 2000 IECC	2000 IECC
New Jersey	95 MEC	Mandatory With Amendments	As stringent as the 95 MEC	1995 CABO MEC with New Jersey modifications. As of September 5, 2006, a proposal has been submitted to adopt a modified version of the 2006 IECC. The State is looking for a January 2007 adoption.
New York	2001 IECC	Mandatory With Amendments	As stringent as the 2001 IECC	2001 IECC with amendments.
Vermont	State Specific Code	Mandatory With Amendments	As stringent as the 2000 IECC	Based upon the 2000 IECC and Vermont's amendments.

Table 2. Commercial Building Energy Codes

	Commercial Code	***Enforcement Status***	***Approximate Stringency***	***Commercial Code Notes***
Connecticut	2003 IECC	Mandatory Without Amendments	As stringent as the 2003 IECC	2003 IECC with reference to ASHRAE 90.1-2001.
Delaware	ASHRAE 99	Mandatory Without Amendments	As stringent as the ASHRAE 99	ASHRAE 90.1-1999 provided that the respective county and municipality government shall exclude agricultural structures from the provisions.
Massachusetts	State Specific Code	Mandatory With Amendments	More stringent than the 2001 IECC	Elements from both the ASHRAE/IESNA 90.1-1999 and the International Energy Conservative Code (IECC), with state specific amendments.
Maryland	2003 IECC	Mandatory Without Amendments	As stringent as the 2003 IECC	
Maine	ASHRAE 01	Mandatory With Amendments	As stringent as the ASHRAE 01	ASHRAE/IESNA 90.1-2001
New Hampshire	2000 IECC	Mandatory Without Amendments	As stringent as the 2000 IECC	2000 IECC with reference to ASHRAE 90.1-1999
New Jersey	ASHRAE 99	Mandatory Without Amendments	As stringent as the ASHRAE 99	ASHRAE/IESNA 90.1-1999 with no modifications. As of September 5, 2006, a proposal has been submitted to adopt a modified version of the 2004 ASHRAE 90.1. The State is looking for a January 2007 adoption.
New York	2001 IECC	Mandatory With Amendments	As stringent as the 2001 IECC	2001 IECC with amendments.
Vermont	State Specific Code	Mandatory With Amendments	More stringent than the ASHRAE 99	Based on 2000 IECC with amendments to include 90.1-1999.

Table 3. Appliance and Equipment Energy Efficiency Standards Status and Implementation Dates (as of November 2006)

X = standard enacted; implementation date as indicated
** See notes for information necessary to interpret this table.*

	AZ	CA[i]	CT	MA	MD	NJ	NY[ii]	OR	RI	VT	WA	
STATUS	*enacted 2005*	*by regulation in 2002, 2004 &2006*	*enacted 2004*	*enacted 11/05*	*enacted 2004*	*enacted 2005*	*enacted 2005*	*enacted 2005*	*enacted 2005; and 2006*	*enacted 05/2006*	*enacted 2005*	2005 Fed. energy law[iii]
Automatic commercial ice makers	X 2008	X 2008					X 2010	X 2008	X 2010		X 2008	Jan. 2010
Ceiling fans and ceiling fan light kits		X[iv] 2006			X 3/2007		X 2007					Jan 2007
Commercial clothes washers	X 2008	X 2005/ 2007	X 7/2007		X 3/2007	X 2007/ 2010		X 2009	X 2007		X 2007	Jan. 2007
Commercial hot food holding cabinets		X 2006							X 2008			
Commercial pre-rinse spray valves	X 2008	X[17] 2006					X 2007	X 2007	X 2007		X 2007	Jan. 2006
Commercial refrigerators and freezers	X 2010	X 2003/ 2006	X 7/2008		X 9/2005	X 2010	X 2010	X 2007	X 2010		X 2007	Jan. 2010
Consumer audio and video products[v]		X 2006/ 2007					X TBD					Not covered
Digital television adapters		X 2007					X TBD					Not covered
High intensity discharge lamp ballasts (mercury vapor)									X 2007			Jan. 2008
Illuminated exit signs	X 2008	X 3/2003	X 7/2006		X 3/2005	X 3/2007	X 2007	X 2007	X 2007		X 2007	Jan. 2006
Large packaged AC >20 tons	X 2010	X 2006/ 2010	X 7/2009		X 8/2005	X 2010	X 2010		X 2010			Jan. 2010
Low-voltage dry-type transformers[vi]	X 2008	X 3/2003	X 7/2006	X 1998	X 3/2005	X 3/2007	X 2003	X 2003	X 2007		X 2007	Jan. 2007
Medium-voltage dry-type transformers				X 2008						X 2008		Not covered
Metal halide lamp fixtures[vii]	X 2008	X 2006/ 2008		X 2009			X 2008	X 2008	X 2008	X 2009	X 2008	Not covered
Pool pumps		2006/ 2008										Not covered
Residential furnaces & boilers[18]				X TBD					X TBD	X TBD		Not covered
Residential furnace fans[1]				X TBD					X TBD	X TBD		Not covered[viii]
Single-voltage external power supplies	X 2008	X 1/2007 7/2007		X 2008			X TBD	X 2007	X 2008	X 2008	X 2008	DOE rule-making[ix]

	AZ	CA[i]	CT	MA	MD	NJ	NY[ii]	OR	RI	VT	WA	
		7/2008 19										
State regulated incandescent reflector lamps (BRs, ERs and R20s)		2008		X 2008			X TBD	X 2007	X 2008	X 2008	X 2007	Not covered
Torchieres	X 2008	X 2003	X 7/2006		X 3/2005	X 3/2007	X 2007	X 2007	X 2007		X 2007	Jan. 2006
Traffic signals (pedestrian)		X 2006					X 2007					Jan. 2006
Traffic signals (vehicular)	X 2008	X 2003	X 7/2006		X 3/2005	X 3/2007	X 2007	X 2007	X 2007		X 2007	Jan. 2006
Unit heaters	X 2008	X 2006	X 7/2006		X 9/2005	X 3/2007	X 2007	X 2007	X 2007		X 2007	Aug. 2008
Walk-in refrigerators and freezers		X 2006							X 2008			
Water dispensers (bottle-type)		X 2006							X 2008			

Source: Appliance Standards Awareness Project, 2006.

Notes:

The last column shows the effective date product standards included in the 2005 federal energy law (EPAct 2005). Under the general rules of federal preemption in EPAct 2005, states which had set standards prior to federal enactment may enforce their state standards up until the federal standards become effective. But, states that have not yet set standards are preempted immediately. State standards with no highlighting (no shading) are now preempted because federal standards will become effective prior to the state implementation date. Those highlighted in yellow (light shading) will be implemented for some period of time before federal standards take effect. The recent federal energy bill has no impact on those with blue highlighting (dark shading).

Unless otherwise shown, standards become effective on January 1. Where two dates are shown, the standard has two levels or components that become effective on different dates.

[i] In addition to the products listed in this table, CA has also adopted standards for general service incandescent lamps evaporative coolers, hot tubs (portable electric spas), under cabinet fluorescent lamps, vending machines and some additional products.

[ii] For most products, the New York legislation requires the implementing agency (Department of State in consultation with New York State Energy Research and Development Authority, NYSERDA) to develop standards by June 30, 2006 and to implement such standards no sooner than six months after issuing final rules. The proceeding to develop these standards (for products not preempted by EPAct 2005) is currently underway.

[iii] In addition to the products in this table, the 2005 federal energy bill also includes standards for dehumidifiers (effective Oct. 2007) and compact fluorescent lamps (effective Jan. 2006) and calls for DOE to develop standards for vending machines and battery chargers. The federal standard for vending machines must be issued by August 2009 to be effective by August 2012; equivalent dates for battery chargers are 2008 and 2011.

[iv] California's initial requirements are limited to labeling and reporting.

[v] These include televisions, compact audio products, DVD players and recorders, and digital television adapters (also listed separately in this table).

[vi] Low voltage dry type transformer standards in MA, NY and OR were set prior to most recent legislation.

[vii] NY and RI metal halide lamp fixture standards are limited to fixtures which are designed and marketed to operate in a vertical position. CA standards apply to vertical, base up fixtures as of 1/2006 and expand to all other fixtures regardless of position effective 1/2008.

[viii] The 2005 federal energy bill clarifies DOE authority to establish electricity use standards for furnaces.

[ix] DOE must issue standard by Aug. 2008; effective by Aug. 2011. State standards are not preempted until a DOE standard goes into effect.