Survey of Clean Power and Energy Efficiency Programs

Prepared for
Ozone Transport Commission

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Executive Summary

The focus in recent years on electric industry restructuring has triggered an intensive review of mechanisms for addressing the environmental impacts of electricity generation and consumption. Whereas ten years ago lively debates were focused on integrated resources planning, environmental externalities, and the first iterations of emission trading, the focus of attention has now shifted to programs funded through "systems benefits charges" renewable and emissions portfolio standards and/or the second iterations of emissions trading, and output-based emissions regulation. While there are legitimate concerns over the environmental impacts associated with electric industry restructuring, the exercise of pulling apart the industry and putting it back together has spurred some innovative approaches to minimizing and mitigating the environmental impact of the electric industry. It is important to note that many of these untested new policies and initiatives are born out of restructuring efforts, but that they do not require electric restructuring.

This survey is the first phase of a two-phase project. This survey identifies and summarizes clean power and energy efficiency programs that are currently planned or on going. The survey focuses on initiatives within the Ozone Transport Commission (OTC) States, but also identifies certain promising options from other states. The purpose of the survey is to provide information in a consistent format on each of the programs, and to identify which programs, or which program aspects, are worthy of additional study as OTC continues its clean energy initiative. The programs included in the report, with brief identification of areas recommended for further analysis, are summarized in Table ES-1, below.

Table ES-1: Summary of Programs and Recommendations

Program Vehicle	Geographic Scope	Program Goal	Recommended Area for Further Analysis
1. Demand Reduction & Energy Efficiency			
1.1 System Benefit Charges Supporting Efficiency	CT, DE, DC, ME, MA NH, NJ, NY, PA, RI, VT.	Fund energy efficiency programs that will reduce electric demand and energy and reduce electricity costs.	Potential emission reductions associated with different energy efficiency programs. Identification of most promising efficiency programs from an air quality perspective. Case study of specific programs or program delivery mechanisms.
1.2 Collaboratively-Designed Efficiency Programs	CT, MA, ME, NH, RI, NJ	To improve upon utility-run DSM with public and technical input to design	
1.3 Independent Efficiency Agency	VT, ME, MA	To improve upon utility-run DSM through an independent agency	

Program Vehicle	Geographic Scope	Program Goal	Recommended Area for Further Analysis
1.4 Rate Incentives for Energy Efficiency	CA	Encourage residential efficiency	
1.5 Load Response - Reserves	New England	Use load response to meet reserve requirements	Air quality implication of the use of distributed generation as a load response measure.
1.6 Load Response – Economic Programs	NE, NY, PJM	To promote load response from retail customers to ensure competitive markets. Customer site diesel generation prohibited from NY economic load response.	
2. Low Emissions Generation – Renewables			
2.1 System Benefits Charges Supporting Renewables	Many, including CT, MA, NJ, NY, PA, RI.	Reduce the up-front costs of new renewable projects, supporting long-term technology cost reductions.	Linkages between SBC and RPS and air-quality goals.
2.2 Renewable Portfolio Standards	Many, including CT, ME, MA, NJ, and PA.	Create demand for renewable resources to decrease air emissions and diversify generation resources	Case study of GIS development and potential for OTR application.
2.3 State and Local Purchasing Requirements	States include MD, NY, and MA. Many cities also have programs	Mandate minimum proportion of state's energy supply by renewables. Foster energy efficiency in state buildings	Case study of GIS development and potential for OTR application.
3. Air Quality Policies – Power System Emission Reduction			
3.1 Emission Performance Standards	CT, MA, NJ	Cap emissions and reduce emission rates associated with retail sales.	Appropriate level of an OTR-wide EPS to achieve air quality goals. Case study of GIS development and potential for OTR application.

Program Vehicle	Geographic Scope	Program Goal	Recommended Area for Further Analysis
3.2 Multi-pollutant Output Based Emissions Standards Targeting High Emission Sources	MA	Reduce emission rates of power plants, and address local air quality.	Case study of multi-pollutant-based approaches for reducing emissions from certain high emission sources.
3.3 Multi-pollutant Output Based Cap and Trade Program Targeting High Emission Sources	NH proposed	Reduce emission rates of power plants through trading.	
3.4 NOx Budget Allocation	MA, NJ, NH, federal	Reduce emissions from power plants, promote generation efficiency, renewables, efficiency.	Evaluate cost implications to specific resources or resource types of output-based allocation.
3.5 Distributed Generation Programs	Texas, New Hampshire, California, national	Control emissions from use of distributed generation in emergency and economic applications	Summary, review and comparison of existing state DG standards and RAP model rule.
3.6 Information Disclosure	CT, ME, MD, MA, NJ, NY, and RI	Provide information on fuel mix and emissions to customers in a consistent and comparable format	Case study of GIS development and potential for OTR application.

Our conclusions from the survey include the following:

- The success of certain programs is contingent upon implementation of the program on a regional basis.
- Regional coordination among environmental regulators in the Ozone Transport Region will enhance the effectiveness of programs where the success of the program in achieving emissions reductions shows a strong correlation to a regional approach.
- Environmental regulators should continue their efforts to integrate environmental and energy policy at both the State and regional levels by working with energy agencies and power system operators on overlapping policies and programs.

- Energy Efficiency represents a “no regrets” approach to emission reductions because it presents a significant opportunity to reduce air emissions at negative costs to society. Energy efficiency programs offer a variety of societal benefits beyond the reduction in air emissions and the reduction of electricity costs. The systems benefit charges established to date do not tap the full economic potential for energy efficiency in the region. It is important to note that the delivery mechanism for energy efficiency (e.g. utility, collaborative, independent agency) can affect the success of energy efficiency programs.

- Load response, where retail electricity consumers modify their electricity usage in response to wholesale market conditions, is critical to achieving efficient wholesale electricity markets and could provide benefits for operation of the interconnected bulk electrical power system. Coordination among environmental and energy regulators, and power system operators can prevent the development of economic load response as a significant new source of air emissions in the Ozone Transport Region.

- Environmental and energy regulators should participate in clearly defining the purpose of a renewables systems benefit charge and should target funding accordingly. Annual review of data can be useful in evaluating the emissions impacts of the implementation of a renewables systems benefit charge.

- A regional generation information system can be an important mechanism for enabling cost-effective compliance with and verification of a renewable portfolio standard. Treatment of biomass facilities can have a significant impact on potential emission reductions associated with a renewable portfolio standard.

- State and local renewable purchasing requirements are most effective in reducing air emissions from the electricity industry when they emphasize the procurement of new renewable resources and are incremental to other policies such as a renewable portfolio standard.

- The effectiveness of an emissions performance standard in reducing regional emissions depends on the scope of the policy, and is most effective on a regional rather than a single state basis. A regional generation information system can be an important mechanism for enabling cost-effective compliance with and verification of an emissions performance standard. States going forward with an EPS should pay careful attention to planned capacity additions when setting emissions performance standard levels

- Programs that focus on achieving emissions reductions from existing, high emission electricity generation sources are very effective in reducing electric system emissions.

- Multi-pollutant approaches to emissions regulations provide efficiencies and economies in implementation, compliance, and compliance verification.

- Output-based emissions approaches (both in rate-based and cap and trade regulations) provide financial incentives that will reward individual sources for improving generation efficiency and result in collateral emission reductions.

- Cap and trade programs can be more cost-effective in achieving a given level of emission reductions than rate-based programs. Rate-based programs can be effective in achieving local air quality improvements.

- Without specific initiatives, such as set-aside programs, to include efficiency programs and renewables in NO_x budget programs, emission reductions from these programs will result in reducing the overall cost of compliance with cap and trade regulations rather than in additional emission reductions from the electric industry.

- Environmental regulators must take specific steps to prevent the growth of emissions from sources that are not yet included in state emission reduction programs, such as distributed generation.

- Information disclosure is an important consumer protection policy and will enhance the success of policies such as renewable portfolio standards and state purchasing requirements. A regional generation information system can be an important mechanism for enabling cost-effective compliance with and verification of a renewable portfolio standard.

In this report we have suggested certain areas for further study, summarized in Table ES-1 above. This report does not recommend specific policies for future implementation. It is very difficult, using available information, to perform a comparative quantitative analysis of the wide variety of policies contained in this survey in order to select among them certain ones for implementation. The programs have a variety of goals, and schedules, they apply to a variety of entities, they are implemented over different geographic areas, and there are numerous other factors that require careful consideration. The suggestions for further study are based on a qualitative evaluation of the following criteria:

- Novelty and innovation
- Emission reduction potential
- Feasibility
- Regulatory coordination
- Regional consistency
- Wide applicability of results
- Consistency with industry trends.

The second phase of this project will provide an opportunity to further review a subset of policies, providing additional information to the Ozone Transport Commission and individual states as they contemplate the development and implementation of a variety of clean energy and emission reduction policies.

The policies that we have reviewed in this survey could all be integral components of regional efforts to achieve environmental and energy policy goals. The Ozone Transport Commission's efforts to review and analyze the programs, and to seek potential areas of improvement and coordinated action, are consistent with regional environmental and energy policy efforts. This sort of integrated approach that includes review of a variety of policies, and considers potential areas for coordination between environmental and energy regulators, is very consistent with the goals established in the recent Climate Change Action Plan of the New England Governors/Eastern Canadian Premiers.[1] Further analysis of certain programs or program aspects in the next phase of this project can contribute to an integrated and coordinated approach such as that recommended in the Climate Change Action Plan for reduction of emissions from the electricity sector and for increased energy efficiency.

[1] Climate Change Action Plan 2001, New England Governors/Eastern Canadian Premiers, prepared by the Committee on the Environment and the Northeast International Committee on Energy of the Conference of New England Governors and Eastern Canadian Premiers, August 2001 http://www.web.net/~ccnb/publications/CCAPe.pdf

List of Acronyms

CA PUC	California PUC
CCCT	Combined Cycle Combustion Turbine
CI	Connecticut Innovations
CT	Combustion Turbine
DEP	Department of Environmental Protection
DG	Distributed Generation
DREM	Distributed Resources Emissions Model
EPA	Environmental Protection Agency
EPS	Emission Performance Standard
FERC	Federal Energy Regulatory Commission
GIS	Generation Information System
GPS	Generation Performance Standard
IRP	Integrated Resource Planning or Plan
ISO	Independent System Operator
NEEP	Northeast Energy Efficiency Partnership
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NESCAUM	New England States for Coordinated Air Use Management
NH DES	New Hampshire Department of Environmental Services
NRDC	The Natural Resources Defense Council
NYSERDA	New York State Energy Research and Development Authority
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PRLWG	Price Responsive Load Working Group
PSC	Public Service Commission
PUC	Public Utilities Commission
RAP	Regulatory Assistance Project
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SBC	System Benefit Charge
SIP	State Implementation Plan

List of Tables and Figures

I. Introduction and Overview

The focus in recent years on electric industry restructuring has triggered an intensive review of mechanisms for addressing the environmental impacts of electricity generation and consumption. Whereas ten years ago lively debates were focused on integrated resources planning, environmental externalities, and the first iterations of emission trading, the focus of attention has now shifted to funding programs through "systems benefits charges," renewable and emissions portfolio standards, the second iteration of emissions trading, and multi-pollutant and output-based strategies. While there are legitimate concerns over the environmental impacts associated with electric industry restructuring, the exercise of pulling apart the industry and putting it back together has spurred some innovative approaches to minimizing and mitigating the environmental impact of the electric industry. It is important to note that many of these untested new policies and initiatives are born out of restructuring efforts, but that they do not require electric restructuring, while substantial reductions from emissions trading have been documented.

The objective of this project is to build on the Ozone Transport Commission's (OTC's) previous clean power and energy efficiency work by developing two resource documents for States to use on clean power and energy efficiency initiatives. This first document provides a survey of Sate clean power and energy efficiency initiatives that have been implemented or are planned for implementation. The second document will provide state program options through more detailed analysis of a few programs.

This report is the first phase of this two-phase project. This survey identifies and summarizes a variety of clean power and energy efficiency programs that are currently planned or on going. The survey focuses on initiatives within the OTC States. We have also identified a few programs from other states to illustrate some innovative approaches.[2] The purpose of this survey is to identify and describe a wide range of mechanisms that have been developed and implemented in recent years to address the environmental impacts of electricity generation and consumption.

For each program we present information in a consistent format to facilitate review and basic understanding of the programs. However, it is important to note that comparison of the programs is complex since the programs reflect a wide variety of goals, formats, implementation methods, and entities involved in implementation. For this survey we have noted a variety of costs and benefits of each program, and we have noted the availability of a variety of evaluations.

This survey is intended to lay the groundwork for the second phase of the project, which will provide further analysis of a subset of programs. The survey suggests numerous programs and program aspects that may be worthy of more detailed analysis in the second phase of the project. The second phase of the project will address a subset of these recommended areas of study.

[2] The selection of programs from outside the OTC States is not intended to be comprehensive; rather we selected a few programs because they illustrated an approach that could be implemented in the OTC States.

In preparing this survey we relied on a variety of information sources including state agencies, available resources in the literature and the Internet, and our own experience participating in the development of a number of these programs over the years. We also conducted selected interviews to supplement the other information sources.

Section II, which constitutes the bulk of this report, is devoted to the survey itself. We present a summary of each program in a consistent format to facilitate comparison of the programs at a broad level. We have grouped the programs in three broad categories: demand reduction and energy efficiency; low emission generation – renewables; and air quality policies - power system emission reductions. Program descriptions are intended to highlight program elements and to identify certain notable aspects of each program including feasibility, potential costs and benefits, available estimates of emission reduction potential, and key issues related to the program. Following each program summary, we provide a list of information sources for the reader who seeks additional information.

Section III of the report describes our method for developing a comparative estimate of potential emission reductions. We have presented our method and assumptions in a clear format, first describing our general method, then discussing the assumptions and method for individual programs. It is important to note that the assumptions that we use drive the estimates of emission reductions; thus we have sought to be very clear about our assumptions. These emission reduction estimates are intended to present relative magnitudes of potential annual emission reductions from the stand-alone implementation of different programs. For illustrative purposes we have normalized the estimates based on application of each policy as a stand-alone policy throughout the states in the OTC during an individual year. This report does not analyze the potential emissions reductions that might occur if more than one of the policies were to be applied simultaneously. Such an analysis would require a more detailed analysis that must be reserved for a separate project.

Section IV of the report provides some observations and conclusions from this initial survey.

In **Section V** of the report we provide suggestions for further analysis of the programs. First, we identify certain criteria to consider in selecting programs and program features for further analysis. In reviewing programs to identify promising areas for further study we have emphasized qualitative criteria, since there are not currently readily available quantitative criteria that permit comparison across different programs. We developed illustrative estimates of potential emission reduction from the stand-alone implementation of many programs; however, the development of other quantitative criteria must be reserved for a different study. Then we suggest a number of different programs or program aspects, based on the application of the criteria, that are worthy of additional and more detailed review. The purpose of these suggestions is to lead into the second phase of the project, by identifying options for in-depth case studies. The focus of this section is on suggesting areas for further review and consideration rather than on identifying programs for implementation, an exercise that will follow the second phase of this project.

II. Survey of Programs

1. Demand Reduction and Energy Efficiency

In this section we discuss policies that are designed to affect the amount and timing of retail electricity consumption. We consider two categories of programs: energy efficiency and load response. The term "energy efficiency" refers to technologies, measures, and practices that reduce the amount of energy required to provide a certain level of energy service (e.g., heating, cooling, lighting, motor drive, etc.). In this report, we focus on energy efficiency opportunities among electricity end-uses. There are many policy options available to promote energy efficiency, including efficiency standards, efficiency programs, pricing incentives, tax incentives, and more. The term "energy efficiency programs" refers to a set of initiatives that provide customers with information, technical services, energy audits, and financial incentives to help them adopt energy efficiency measures. These programs are often run by a central agency, such as an electric utility or a government agency, and are intended to overcome the many market barriers that tend to prevent customers from adopting cost-effective energy efficiency measures on their own. Efficiency programs offer one of the most effective policy options for achieving energy efficiency savings.

The term "load response" refers to actions of one or several retail customers to reduce their electrical consumption at specific times in response to wholesale market conditions at specific times. Load response actions introduce demand elasticity into wholesale electricity markets. Increased load responsiveness is widely recognized as an essential component of efficient and competitive wholesale electricity markets. In this report, we focus on certain programs intended to increase load responsiveness in wholesale electricity markets.[3]

1.1 System Benefit Charges Supporting Efficiency

Program Description

Program Vehicle – System benefit charges (SBCs) are charges included in every customer's bill to raise funds to support programs that offer benefits to all customers and society in general, such as energy efficiency, research and development, renewables and low-income customer assistance. Very often, the charges were put in place as part of electricity industry restructuring, but some states that have not restructured yet also have SBCs. The charges (in $/MWh) are designed to be non-bypassable, to ensure that those

[3] In this report the term "load response programs" includes programs that enable real-time load response as well as those that enable demand bidding.

customers who choose competitive power supplies will continue to pay them along with other customers.

Geographic Scope – States that have developed or are developing SBCs to support energy efficiency are CT, DC, DE, MA, ME, NH, NJ, NY, PA, RI, VT. This includes every state in the Ozone Transport Region (OTR) except for Maryland and Virginia.

Enabling Authority – State Legislatures.

Program Duration – Table 1 below presents a summary of the program duration for each OTC state with an SBC. Some programs have a limited duration, such as five years, whereas others are on going, with renewal required from the state legislature every few years in order for the programs to continue.

Table 1: System Benefits Charges to Support Energy Efficiency – Duration of Programs

State	Date of implementation	Termination of Program	Next reassessment
Connecticut	January 1, 2000	No end-date	NA
Delaware	October 1, 1999	No end-date	NA
DC	May 3, 2000	NA	NA
Maine	Law enacted November 1999	No end-date	Review "regularly"
Maryland	1999 Act	June 30, 2005	Funding non-lapsing
Massachusetts	Funding started March 1, 1998	December 31, 2002	Legislature determines status after 2002
New Hampshire	May 1, 2001	33 months after start of competition	NA
New Jersey	March 1, 2001	2008	2007 (thereafter on a 4-year basis)
New York	July 1, 1998	June 30, 2006	Last renewed in 1/2001
Pennsylvania	1999	2010	Funding determined for 1999-2002
Rhode Island	1998	2006	2006
Vermont	February 2000	December 31, 2004	2003-04

Program Goal – The goal of an SBC is to provide a stable flow of funds to support efficiency and other public benefit programs. Prior to the introduction of electricity restructuring, many utilities were required to finance energy efficiency programs by including the costs in customer rates. The advent of restructuring, and in many cases just the *expectation* of restructuring, caused many utilities to be concerned that they would not be able to recover the costs of energy efficiency, as customers shopped on the basis of electricity prices and switched to competitive generation companies. The SBC was designed to allay these fears, because it applies to all distribution customers, regardless of where they purchase their generation services.

The primary goal of the energy efficiency programs is to lower the total cost of electricity services, by improving the efficiency with which electricity is consumed. Secondary goals include: reduced air emissions, improved reliability, low-income benefits, and economic development.

Program Implementation

Implementing Agencies – The implementing agency is usually the state Public Utility Commission (PUC) or Public Service Commission (PSC) supervising the organization providing services.

Organization Providing Service – Most of the efficiency programs are managed by the electric utilities. Sometimes the programs are designed and managed in a collaborative fashion (see Section 1.2) and sometimes they are managed by an independent agency (see Section 1.3).

Administrative Complexity – Low to high. The administration of an SBC itself is not complex. Once the level of the charge has been established, each distribution company includes that charge on customers' bills and keeps track of the revenues generated. In many cases, this process is simply a continuation of past practices for generating revenues for efficiency programs.

However, delivering energy efficiency programs successfully requires a high degree of administrative complexity. Well-designed efficiency programs should address all customer types and a variety of end-uses. This requires a comprehensive approach to design, marketing, delivering, monitoring and evaluating many different programs. The marketing efforts, financial incentives and program designs should vary by customer type, because different customers face different market barriers to energy efficiency. In most cases, the utilities need to hire and manage a host of energy service companies to work with customers and implement the efficiency measures.

Feasibility – Highly feasible. Many of the SBCs in place today are a result of negotiations that occurred during the development of restructuring legislation. Many utilities in the Northeast have a history of implementing energy efficiency programs. The relevant state Public utility commission must provide meaningful regulatory support and oversight to ensure that the electric utility is provided with sufficient guidance and incentive. One of the most difficult issues to negotiate is how large the SBC should be. Another difficult issue to negotiate is what type of organization should manage the efficiency funds: the utilities or an independent agency (see Section 1.3).

Input to Program Development – The extent of public input depends on the legislative process that is used to develop the electricity restructuring law in each state, and the regulatory process for approving efficiency programs. When states reauthorize SBCs, there is frequently some process to allow for public input. Those states with collaborative processes (see Section 1.2) and those using independent efficiency agencies (see Section 1.3) tend to provide greater public input to the process than those states with more limited, utility-run programs.

Program Assessment

Costs and Benefits – The primary cost of the SBC, and associated efficiency programs, is the additional charge on each customer's bill. In some cases, participating customers are also required to pay a portion of the incremental efficiency costs. The primary benefit of energy efficiency programs is the reduced cost of electricity services, as a result of less electricity generation, and deferred or avoided construction of new power plants or transmission and distribution facilities. The costs tend to be incurred in the short-term, while the benefits are enjoyed over both the short-term and long-term future. Hence, it is important to conduct cost-benefit analyses over a long enough planning horizon to capture all the long-term benefits.

The legislation establishing SBCs, and the PUCs that oversee them, require that the energy efficiency programs be cost-effective – i.e., that the present value of the lifecycle benefits exceed the present value of the lifecycle costs. Therefore, efficiency programs, by design, will always result in a net *reduction* in electricity costs. Each program, by each utility, in each state will have its own benefit-cost ratio. The benefit-cost ratios tend to range from around 1.0 to as high as 2.0 or 3.0. In some cases, efficiency programs for low-income customers have benefit-cost ratios less than one, but these are deemed to be cost-effective because of the many additional benefits to customers and society that they provide.

Some states have policies that require environmental benefits to be considered in determining the cost-effectiveness of efficiency programs. Such policies should increase the amount of energy efficiency that is considered cost-effective. However, with the advent of the SBC, such policies do not necessarily increase the amount of energy efficiency savings that are achieved in practice. The primary determinant of the achieved energy efficiency savings will be the total amount of efficiency funds that have been identified for the SBC. In all cases that we are aware of, this funding level is insufficient to capture the full amount of cost-effective efficiency savings – even without considering environmental benefits. Consequently, increasing the cost-effective standard with environmental considerations will not increase the amount of efficiency savings that are achieved, unless additional funding is made available.

Nonetheless, if the environmental benefits of energy efficiency are properly accounted for in the cost-benefit analysis, then the program administrators might place greater emphasis on those efficiency measures and programs that result in greater air emission reductions. For example, greater emphasis might be placed on efficiency measures that achieve savings frequently throughout the day and the year, and less emphasis on those efficiency programs that only achieve savings during peak periods (see Section III.2.)

Efficiency programs also provide many societal benefits, in addition to the primary benefits of reduced electricity costs. These benefits include:

- Increased reliability of the electricity system, as a result of lower electricity demand growth;
- Reduced costs of wholesale power, with benefits to all customers, as a result of reducing electricity demand during high-cost, peak periods;

- Less reliance upon imported oil;
- Reduced environmental impacts of from electricity generation, as well as reduced impacts from transmission and distribution facilities, fossil and nuclear fuel production, and liquid and solid waste processing.
- Improved working conditions and higher productivity in commercial and industrial settings;
- Reduced water, oil and gas consumption, as well as lower maintenance costs, in the homes and or businesses of the program participants;
- Reduced costs to utilities associated with arrearages, bad debt, terminations, reconnections and rate discounts;
- A variety of benefits to low-income customers, including improved health, improved housing conditions, improved property values, maintenance of utility services and reduced moving and homelessness.

The extent to which these benefits are achieved depends upon the participating customers, the end-uses addressed, and the amount of program funding available.

Emission Reduction Potential by Pollutant – There are many factors that affect the emission reduction potential from energy efficiency programs. The most important factor is the amount of funding dedicated to energy efficiency programs. Table 2 below presents a summary of the SBC amounts of each of the OTC states. As indicated in the table, the amount of funds dedicated to energy efficiency varies widely across the states, ranging from $0.1/MWh in Pennsylvania to $3.0/MWh in Connecticut.

Table 2: System Benefit Charges in the OTC States

State	Million $	$/MWh	% of Retail Revenues	Administration
Connecticut	87	3.0	3	Utility/Collaboration
Delaware	1.5	0.18	0.3	State
Washington DC	TBD	TBD	TBD	City
Maine	17.2	1.5	1.5	State
Massachusetts*	130	3.0	3	Utility/Collaboration
New Hampshire**	18	1.8	1.6	Utility
New Jersey	89.5	1.35	1.35	Statewide Utilities/ NJBPU-NJDEP
New York	83	0.83	0.7	State/NYSERDA
Pennsylvania	11	0.1	0.1	Utility
Rhode Island	14	2.1	2.1	Utility/Collaboration
Vermont	13.1	2.5	2.6	Independent Agency

***** *In Massachusetts the amount of the SBC ramps down from 1998 through 2002.*

***In New Hampshire the 2001 SBC is 0.8 $/MWh ($8.7 million), and ramps up to 1.8 $/MWh ($18 million) in 2002 and 2003.*

Another important factor affecting the emission reduction potential from efficiency programs is the success of the program in overcoming the many market barriers to energy efficiency. For example, programs that only provide information and education about efficiency are rarely sufficient to overcome the transaction costs and financing requirements that tend to hinder efficiency investments. At the other end of the spectrum, programs that provide customers with education, technical advice, financial incentives, assistance with installation and long-term support are much more likely to achieve significant electricity savings.

In addition, the emission reduction potential from efficiency programs may depend upon regulatory oversight and the public input to the efficiency programs. Collaboratively designed efficiency programs, which include input from the various energy stakeholders in the state or region, tend to provide greater opportunities for maximizing the efficiency savings from a given efficiency fund (see Section 1.2).

Furthermore, the emission reduction potential from efficiency programs may depend upon the entity that manages the program, and the incentive that such entity has to maximize energy savings. Utilities face significant financial disincentives to achieving energy efficiency savings, whereas independent agencies do not face such disincentives and can make the achievement of efficiency savings be one of their key objectives (see Section 1.3).

Program Evaluation – Many states require that utilities prepare an annual report documenting their efficiency program expenditures and savings. The extent of the program monitoring and evaluation varies widely across the OTC region, thus it is difficult to draw general conclusions regarding energy efficiency program evaluation on a region-wide basis.

Massachusetts's utilities have some of the most comprehensive and detailed evaluation practices, based on a long history of program delivery and regulatory oversight, and the Massachusetts Division of Energy Resources compiles the utilities' reports into a single annual report of efficiency savings. The most recent annual report covers efficiency program experience for the calendar year 1999 (see Section 1.2).

In Connecticut the Energy Conservation Management Board acts as an advisor to the Department of Public Utility Control and the state's electric utilities in formulating the efficiency programs funded by the SBC. This Board provides an annual report to the state legislature describing the progress of the efficiency programs, including costs, energy savings, bill reductions, and emissions reductions (see Section 1.2).

The New York State Energy Research and Development Authority (NYSERDA) manages a large portion of the SBC funds in New York. NYSERDA prepares a quarterly report to the New York Department of Public Service detailing the progress of the efficiency programs, including costs, energy savings, bill reductions, and environmental and economic benefits (see Section 1.3).

In New Jersey, the NJBPU, with NJDEP, requires quarterly reporting on the annual and cumulative impacts of efficiency activities from the seven New Jersey electric and natural gas utilities that jointly manage the statewide program. These reports include estimates of energy savings, as well as estimates of avoided air emissions and environmental benefits.

The Northeast Energy Efficiency Partnership (NEEP) is a non-profit organization dedicated to promoting regional coordination of energy efficiency initiatives. NEEP would be a natural organization for collecting and organizing evaluations from energy efficiency programs in the region, and expressed an interest in such a role, but as yet has not obtained sufficient funding and resources to accomplish this task.

Key Issues

In general, the primary goal of efficiency programs is to lower the cost of providing electricity services. Reducing air emissions from electricity generation is typically a secondary goal, if it is acknowledged as a goal at all. If reducing air emissions were given higher priority, then there would be a much greater efficiency savings available than are now being pursued.

The amount of funds set aside for efficiency programs tends to be well below the amount necessary to achieve the full potential for cost-effective efficiency savings. Hence, there is a large amount of untapped efficiency savings that could be achieved at a net negative cost. Consequently, there is a large untapped opportunity for efficiency to reduce air emissions for net negative costs. In addition, if society is willing to pay *positive* costs for energy efficiency to reduce air emissions, then there would be an even larger untapped opportunity for efficiency to achieve this goal.

Utility-run efficiency programs can be significantly hampered by the fact that electric utilities' profits increase with higher sales and decrease with lower sales. Consequently, efficiency programs work directly against the primary goals of electric utilities by reducing electricity sales and profits. This is true whether the utility is vertically integrated or is a distribution-only utility.

Nearly two decades of experience with utility-run efficiency programs has demonstrated that significant regulatory oversight, guidance, and pressure may be necessary to overcome utilities' natural resistance to reducing electricity sales and profits. A variety of regulatory policies have evolved to support utility-run efficiency programs, including public participation, periodic planning processes, various cost recovery approaches, recovery of lost base revenues, and shareholder incentives. These policies were often developed and implemented in the context of Integrated Resource Planning (IRP) requirements.

With the advent of electricity industry restructuring, many commissions abandoned the IRP approach and moved to reduce regulatory oversight of utility activities in general. This trend increased the need for certainty of cost recovery, which was one of the motivating factors behind the system benefits charges. This trend also increased the need for alternative forms of public and regulatory input to efficiency programs through collaborative processes (see Section 1.2), and for independent agencies to implement the new energy efficiency programs (see Section 1.3).

While SBCs have primarily been established in the context of electricity industry restructuring, they are very useful mechanisms for supporting efficiency even in those states that have not restructured. They provide a stable source of efficiency funding, eliminate many of the risks to the electric utilities, and provide long-term commitment to efficiency initiatives.

The size of the SBC, and thus the amount of funds raised for efficiency, will be the most important factor in determining the emission reduction potential from energy efficiency programs. Another critical factor in the emission reduction potential is the ability of the organization providing the efficiency service to manage and implement the programs effectively and efficiently. In Sections 1.2 and 1.3 we discuss some of the different options for managing the efficiency programs.

Similarly, the duration of the SBC will have important implications for the amount of emissions that can be reduced over time. Those states that ramp down the level of the SBC, or that terminate the SBC after a fixed period, create uncertainties among the program administrators, providers and recipients, and may hinder long-term implementation and market transformation. A greater amount of efficiency savings, and therefore emission reductions, will be obtained if the SBCs are put in place indefinitely. In such a case, the SBC can be phased out once it can be determined that the efficiency market has been sufficiently transformed to the point where all the cost-effective efficiency measures will be adopted by market actors without public policy support.

For the purposes of reducing air emissions, the SBC could be in place even after the market had been so transformed, because efficiency that is not cost-effective can still represent a low-cost option for reducing emissions.[4] An efficiency program whose costs slightly exceeds its benefits will typically be considered not cost-effective, but might still have a net cost much less than other options for reducing air emissions.

One limitation to many of the SBCs established to date is that they frequently do not apply to the municipal electric utilities and the electric cooperatives. This usually occurs because the Public Service Commission frequently does not have regulatory jurisdiction over these types of agencies. Consequently, some electricity customers are not contributing to the fund and are not benefiting from efficiency measures.

Sources of Information

American Council for an Energy Efficient Economy (ACEEE), *A Revised 50-State Status Report on Electric Restructuring and Public Benefits*, Kushler and Witte, March 2001.

Connecticut Energy Conservation Management Board, *Year 2000-2001 Programs and Operations*, prepared for the State Legislature's Energy & Technology Committee, Environment Committee, January 31, 2001.

Efficiency Vermont, *Annual Report 2000*, http://www.efficiencyvermont.com/

[4] This occurs when the definition of cost-effective does not include the environmental benefits of the energy efficiency savings, which is often the case.

Environmental Protection Agency, *Creating an Energy Efficiency and Renewable Set-Aside in the NO_X Budget Trading Program: Designing the Administrative and Quantitative Elements*, Climate Protection Division, April 2000.

Maryland Public Service Commission, *Report on Energy Efficiency and Conservation Programs*, February 2001, http://www.psc.state.md.us/psc/

Massachusetts Division of Energy Resources, *Energy Efficiency Activities 1999*, an Annual Report to the Great and General Court on the Status of Energy Efficiency Activities in Massachusetts, Spring 2001.

Maine State Planning Office, *Maine Electric Energy Conservation Program*, November 2001.

NARUC Electric Restructuring Data Base, http://www.naruc.whatsup.net/customers/naruc/naruc.nsf

New Hampshire Public Utilities Commission, *Order Approving Settlement Agreement and Joint Request for Modification of Previous Commission Determination*, Docket 01-057, Order No. 23,850, November 29, 2001.

New Jersey Web Sites: http://www.state.nj.us/bpu. http:/state.nj.us/dep/dsr/gcc. http://www.cleanenergy.com/. http://www.njsmartstartbuildings.com/.

New York State Energy Research and Development Authority (NYSERDA), *New York Energy $mart K Program Evaluation and Status Report*, Quarterly Report to the New York State Department of Public Service, June 2001.

Northeast Energy Efficiency Partnership (NEEP), personal communications with Elizabeth Titus, November 2001.

1.2 Collaboratively-Designed Efficiency Programs

Program Description

Program Vehicle –Energy efficiency programs are designed through a collaborative process, whereby various efficiency stakeholders work directly with the electric utility to design and implement efficiency programs. In some cases, there is also coordination among utilities and collaborative efforts, in order to develop consistent efficiency programs within a state.

Since the electric utility is the central agent implementing the efficiency programs, the collaboratively designed efficiency programs are a subset of the utility-run programs described in the previous section. All of the collaboratively designed efficiency programs in the OTC region are funded by revenues raised from a system benefits charge (see Section 1.1).

Geographic Scope – CT, ME, MA, NH, NJ, RI.

Enabling Authority –Efficiency collaboratives are usually established through settlements among the interested parties and stakeholders. The settlements are reviewed and approved by the relevant state Public Utility Commission.

Program Duration – Varies by state (see Section 1.1).

Program Goal –Collaboratively designed efficiency is intended to improve upon utility-run efficiency by allowing efficiency advocates and other stakeholders to provide technical support and policy guidance during program development.

The primary goal of the energy efficiency programs is to lower the total cost of electricity services, by improving the efficiency with which electricity is consumed. Secondary goals include: reduced air emissions, fuel diversity, improved reliability, low-income benefits, and economic development.

Program Implementation

Implementing Agencies – In general, Public Utility Commissions review and oversee energy efficiency programs developed by electric utilities. In addition, issues that cannot be agreed upon by all members of the collaborative process can be brought to the PUC for resolution.

Organization Providing Service – Electric distribution companies. Independent, for-profit energy service vendors are frequently hired by the distribution companies to market and deliver efficiency services to customers.

Administrative Complexity – High. Delivering energy efficiency programs in general requires a high degree of administrative complexity (see Section 1.1). The additional effort to collaborate among stakeholders requires good-faith negotiation efforts among parties that sometimes have conflicting interests.

Feasibility – High. There must be sufficient political will among the collaborators and the state Public utility commission to achieve and approve a settlement. This approach is often considered preferable to the alternative: each party litigating their issues before the PUC after the utility has designed and proposed efficiency programs.

Input to Program Development – The collaboratives tend to include consumer advocates, efficiency advocates, low-income advocates, and environmental advocates. These stakeholders provide significantly more public input to the process than is typically provided in utility-run energy efficiency programs. The difference is that these stakeholders are allowed to help formulate the efficiency programs throughout the design process, as opposed to simply critiquing the efficiency programs in an adjudicatory proceeding after they are already designed.

Program Assessment

Costs and Benefits – The statutory and regulatory provisions that authorize utility-run efficiency require that the programs be cost-effective. Therefore, collaborative efficiency programs, by design, will always result in a net *reduction* in electricity costs. Each program, by each utility, in each state will have its own benefit-cost ratio. The benefit-cost ratios tend to range from around 1.0 to as high as 2.0 or 3.0. (See Section 1.1 for more details.)

In the absence of collaborative processes, efficiency advocates and other stakeholders have little ability to influence utility-run efficiency programs. Their main opportunity is through litigated cases before the PUC – which can be contentious, expensive and time-consuming, and may only allow for minor, after-the-fact improvements to the efficiency programs. Collaborative processes offer the advantages of significantly greater input to program design by the various stakeholders, from the beginning to the end of the design process. They also allow utilities and stakeholders to gain a better understanding of each other's interests and perspectives, leading to greater potential for compromise and agreement.

In Massachusetts in 1999 the utility energy efficiency programs across the state spent $125 million and saved $254 million in avoided electricity costs. This means the efficiency programs had a net benefit of $129 million, and a benefit-cost ratio of 2.0. These programs resulted in annual efficiency savings of 273 GWh, and lifetime efficiency savings of 3,822 GWh. These programs are estimated to have an average cost of $33/MWh.[5]

In Connecticut in 2000 the utility energy efficiency programs across the state spent $84 million and saved $104 million in avoided electricity costs. This means the efficiency programs had a net benefit of $20 million, and a benefit-cost ratio of 1.2. These programs resulted in annual efficiency savings of 252 GWh, and lifetime efficiency savings of 3,703 GWh. These programs are estimated to have an average cost of $23/MWh.

Emission Reduction Potential by Pollutant – See Section 1.1 for an overview discussion of this issue. In Section III we provide independent estimates of the emission reduction potential from efficiency programs. These estimates are prepared in such a way that they can be compared with similar estimates for other policies discussed in this report.

According to the annual report prepared by the Massachusetts Division of Energy Resources, the efficiency programs implemented by Massachusetts electric utilities in 1999 resulted in 770 tons of annual SO_2 reductions, 453 tons of annual NO_X reductions and 145,000 tons of annual CO_2 reductions.

According to the annual report prepared by the Connecticut Energy Conservation Management Board, the efficiency programs implemented by Connecticut electric utilities in 2000 resulted in 843 tons of annual SO_2 reductions, 286 tons of annual NO_X reductions and 206,712 tons of annual CO_2 reductions.

[5] The cost of saved energy figures presented in this report are based on lifetime energy efficiency savings, not annual. Also, it is important not to compare or confuse the cost of saved energy (in $/MWh) with the SBC amount (also in $/MWh). The denominator in the cost of saved energy refers to the amount of efficiency savings. The denominator in the SBC refers to the total retail electricity sales. The former is an indication of how much efficiency can be achieved from a given investment. The latter is simply an measure of how much revenues can be generated to support energy efficiency activities.

Program Evaluation – Many states require that utilities prepare an annual report documenting their efficiency program expenditures and savings. The extent of the program monitoring and evaluation varies widely across the OTC region, thus it is difficult to draw many conclusions regarding energy efficiency program evaluation on a region-wide basis. See Section 1.1.

Key Issues

In order to encourage good-faith negotiations, it is important that stakeholders have the opportunity to bring any issues that are unresolved or cannot be agreed upon to the Public Utility Commission for resolution in a timely fashion.

Stakeholders are able to have much more substantial and meaningful input to the development of efficiency programs if the utility provides funding for technical consultants. The technical consultants can assist in the development of all aspects of program design and implementation, and can help share information and experiences from other utilities and states implementing efficiency programs. Stakeholders should be able to reach an agreement on who the technical consultants should be. Funding for the consultants should come from the overall efficiency funds.

The efficiency collaborative must include a broad enough range of stakeholders to cover a variety of perspectives. The most important stakeholders to include are: consumer advocates, environmental advocates, low-income representatives, representatives of the efficiency industry, and government representatives such as state energy offices. Each stakeholder must have the ability to actively participate and advocate for their constituents' interests.

Sources of Information

American Council for an Energy Efficient Economy (ACEEE), *A Revised 50-State Status Report on Electric Restructuring and Public Benefits*, Kushler and Witte, March 2001.

Connecticut Energy Conservation Management Board, *Year 2000-2001 Programs and Operations*, prepared for the State Legislature's Energy & Technology Committee, Environment Committee, January 31, 2001.

Maryland Public Service Commission, *Report on Energy Efficiency and Conservation Programs*, February 2001, http://www.psc.state.md.us/psc/

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NARUC Electric Restructuring Data Base, http://www.naruc.whatsup.net/customers/naruc/naruc.nsf

New Hampshire Public Utilities Commission, *Order Approving Settlement Agreement and Joint Request for Modification of Previous Commission Determination*, Docket 01-057, Order No. 23,850, November 29, 2001.

1.3 Independent Efficiency Agency

Program Description

Program Vehicle –The energy efficiency funds collected through the SBC are turned over to a non-utility – i.e., independent – agency to design and implement the efficiency programs.

Geographic Scope – Vermont (Efficiency Vermont); Massachusetts (Cape Light Compact); Maine (Program Administrator, proposed); and New York (the New York State Energy Research and Development Authority).

Enabling Authority – State legislatures and Public Utility Commissions.

Program Duration –

Vermont: Efficiency Vermont began providing efficiency services on March 1, 2000.

Massachusetts: The Cape Light Compact began providing efficiency services on July 1, 2001.

Maine: The State Planning Office is considering whether to use an independent agency to implement efficiency programs.

New York: The New York State Energy Research and Development Authority was given authority in 1998 to implement efficiency programs using funds raised from the SBC.

Program Goal – Independent efficiency agencies are intended to improve upon utility-run efficiency programs because they do not have a financial incentive to maintain or increase electricity sales. Instead, independent efficiency agencies have the reduction of electricity demand and energy, and the reduction of electricity costs, as their core organizational mission.

The primary goal of the energy efficiency programs is to lower the total cost of electricity services, by improving the efficiency with which electricity is consumed. Secondary goals include: reduced air emissions, fuel diversity, improved reliability, low-income benefits, and economic development.

Program Implementation

Implementing Agencies – In general, Public Utility Commissions have some authority over energy efficiency programs implemented by independent agencies. However, their level of regulatory oversight over independent agencies generally tends to be significantly less than that over electric utilities.

Organization Providing Service –

Massachusetts: The Cape Light Compact is a municipal aggregator that is providing energy efficiency services to all customers on Cape Cod and Martha's Vineyard instead of the local electric utility.

Maine: The State Planning Office is considering a proposal for an Efficiency Program Administrator to manage and coordinate all of the utilities' energy efficiency programs.

New York: The New York State Energy Research and Development Authority (NYSERDA) has been designated with the authority to administer most (roughly 75%) of the public benefits funds raised through the SBC. The remainder of the funds has been allocated to the six investor-owned utilities in the state to support on-going public benefits activities.

Vermont: Efficiency Vermont is an independent, non-profit entity that provides energy efficiency services to all of the electric service territories in Vermont.

Administrative Complexity – Medium to High. Delivering energy efficiency programs in general requires a high degree of administrative complexity (see Section 1.1). Using an independent agency can be more complex than using a utility, in that it is necessary to set up a new organizational structure. On the other hand, the new independent organization has a clearer mission and goals, and does not have the inherent conflict that a utility has.

Feasibility – High. There must be sufficient political will in the enabling authority to (a) achieve efficiency savings, and (b) replace existing utility-run efficiency programs with an independent agency. Some utilities may be reluctant to give up their efficiency programs to an independent agency because then they would lose control over the SBC funds and the type and extent of efficiency savings that would be achieved.

Input to Program Development –

Massachusetts: The Cape Light Compact solicits input to its plans from citizens, through town meetings, town representatives, and other local channels. The Compact has also held various public meetings to solicit input from Massachusetts energy efficiency stakeholders.

Maine: The State Planning Office is soliciting input from the stakeholders in the Maine Conservation Plan.

Vermont: Efficiency Vermont is operated under contract to the Vermont Public Service Board.

Program Assessment

Costs and Benefits – The statutory and regulatory provisions that authorize utility-run efficiency require that the programs be cost-effective. Therefore, efficiency programs offered by independent agencies, by design, will always result in a net *reduction* in electricity costs. (See Section 1.1 for more details.)

One of the advantages of independent agencies delivering efficiency programs is that there is no need to provide shareholder incentives to encourage successful programs. This frees up funds that can instead be used to achieve efficiency savings.

Another advantage is that an independent agency can adopt a societal perspective, and can pursue efficiency initiatives that are in society's best interests, even if they are not in the electric utility's best interests. For example, the Cape Light Compact is implementing a program to switch customers from inefficient electric space heat to highly-efficiency gas or oil heat. Electric utilities are ardently opposed to such programs because they significantly reduce their market share.

In New York the NYSERDA spent $114 million on efficiency programs through March 31, 2001. These programs resulted in annual efficiency savings of 730,000 MWh, at an average cost of $30/MWh.[6]

In 2000 Efficiency Vermont spent $5.4 million on efficiency programs and saved $17.7 million in avoided costs.[7] This means that the efficiency programs had a net benefit of $12.3 million, and a benefit-cost ratio of 3.3. These programs resulted in annual efficiency savings of 23,335 MWh, at an average cost of $16/MWh.

Emission Reduction Potential by Pollutant – See Section 1.1 for an overview discussion of this issue. In Section III we provide independent estimates of the emission reduction potential from efficiency programs. These estimates are prepared in such a way that they can be compared with similar estimates for other policies discussed in this report.

In New York the efficiency programs implemented by NYSERDA resulted in 548 tons of SO_2 reductions per year, 1102 tons of NO_X reductions per year, and 321,935 tons of CO_2 reductions per year.

The efficiency programs implemented by Efficiency Vermont in 2000 resulted in 71 tons of SO_2 reductions per year, 27 tons of NO_X reductions per year, and 17,443 tons of CO_2 reductions per year.

Program Evaluation – Many states require that utilities prepare an annual report documenting their efficiency program expenditures and savings. The extent of the program monitoring and evaluation varies widely across the OTC region, thus it is difficult to draw many conclusions regarding energy efficiency program evaluation on a region-wide basis.

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[6] The cost of saved energy figures presented in this report are based on lifetime energy efficiency savings, not annual. Also, it is important not to compare or confuse the cost of saved energy (in $/MWh) with the SBC amount (also in $/MWh). The denominator in the cost of saved energy refers to the amount of efficiency savings. The denominator in the SBC refers to the total retail electricity sales. The former is an indication of how much efficiency can be achieved from a given investment. The latter is simply an measure of how much revenues can be generated to support energy efficiency activities.

[7] Efficiency Vermont began its operations on March 1, 2000.

Key Issues

It is hoped that independent energy efficiency agencies will be much more effective than electric companies in designing and implementing successful and aggressive efficiency programs. Independent agencies do not face the significant financial and institutional barriers to efficiency that utilities face. Furthermore, independent agencies can make the achievement of efficiency savings their primary organizational mission, and can build the necessary expertise and management structure to pursue this goal as effectively as possible. This more focused organizational mission will allow an independent efficiency agency to achieve the highest level of efficiency savings with the amount of funding that is available.

In order for an independent efficiency agency to achieve its goals effectively, it should have the management structure and the technical resources to undertake what can be a complex administrative task. Assigning the responsibility for this important task to an existing government agency that does not have the appropriate expertise or management structure could jeopardize its success. Efficiency Vermont has set a good example by hiring a contractor – Vermont Energy Investment Corporation – with a proven track record of designing and implementing successful efficiency programs.

While municipal aggregation offers the advantage of public input and control of efficiency funds, it has the disadvantage of potentially creating a fractured patchwork of efficiency programs within a state or region. It also requires that the participating municipalities have the interest and the capacity to undertake what can be a complex administrative task.

Sources of Information

Efficiency Vermont, *Annual Report 2000*, http://www.efficiencyvermont.com/

Cape Light Compact, *Cape Light Compact Energy Efficiency Plan*, submitted to the Massachusetts Department of Telecommunications and Energy, November 11, 2000, http://www.capelightcompactenergysave.com/

Maine State Planning Office, *Maine Electric Energy Conservation Program*, November 2001.

New York State Energy Research and Development Authority (NYSERDA), *New York Energy $mart K Program Evaluation and Status Report*, Quarterly Report to the New York State Department of Public Service, June 2001.

1.4 Rate Incentives for Energy Efficiency

Program Description

Program Vehicle – Rate design for residential electric customers is steeply inverted, creating an incentive for energy conservation. The CA PUC's new residential rate design "fundamentally change[s] how residential customers will pay for the electricity they use."[8] All residential usage below 130% of baseline is exempted from further rate surcharges as mandated by statute AB 1x. For residential customers who use more than 130% of baseline, each additional kilowatt-hour used will be charged at an increasingly higher rate.[9] The PUC adopts five residential rate tiers that correlate to the amount of electricity used per month and allocate the rate surcharge to be paid by the three highest usage tiers as follows:

Tier 1: up to 100% of baseline	No increase by statute
Tier 2: 100-130% of baseline	No increase by statute
Tier 3: 130-200% of baseline	12% increase or less, depending on usage
Tier 4: 200-300% of baseline	29% increase or less, depending on usage
Tier 5: over 300% of baseline	47% increase or less, depending on usage

Geographic Scope – Southern California Edison and Pacific Gas and Electric service territories.

Enabling Authority – General ratemaking authority, and California Statute AB 1x.

Program Duration – Rates effective June 1, 2001

Program Goal – Promote conservation in order to reduce energy demand and energy usage. In addition, the PUC was seeking equitable allocation of a necessary rate increase.[10]

Program Implementation

Implementing Agencies – California Public Utilities Commission (CA PUC)

Organization Providing Service – Southern California Edison and Pacific Gas and Electric

Administrative Complexity – Low.

Feasibility – Highly dependent on political circumstances. For example, this rate design was adopted during a period where most stakeholders in California were seeking every possible approach to reducing consumers' exposure to high and volatile prices in wholesale electricity markets. An inverted rate design would be much more difficult to establish in a time or area where there was no perceived crisis in electricity markets. Rate design is likely to be most effective when coupled with strong consumer education efforts.

Input to Program Development – The new rate design was developed through a rate case, enabling public participation.

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[8] PUC Decision 01-05-064, May 15, 2001, at 3-4.

[9] Baselines are adjusted by climate zone.

[10] PUC Decision at 8-9.

Program Assessment

Costs and Benefits – (budget levels, sources and types of funding, environmental and public health benefits). The inverted rate design results in a higher proportion of a rate increase being borne by high volume consumers. There is little or no administrative cost to this program since it simply charges customers based on their consumption patterns and does not require any additional work on the part of the public utilities commission, the distribution utility, or any competitive supplier. An obvious benefit is that it creates a strong incentive for consumers to take steps to increase the efficiency of their electricity consumption.

Emission Reduction Potential by Pollutant – (annual and program lifetime). This policy was adopted as a mechanism to address market conditions and reliability concerns rather than to pursue an environmental policy goal. However, as with other programs to promote energy efficiency, each kilowatthour saved will result in the avoidance of emissions from the electric power system. The residential rate design creates an incentive to reduce total electrical consumption, rather than peak electrical consumption, since their is no time of use component of the rate structure. Consequently, the program is likely to displace system marginal emissions rather than system peak emissions. Of course, a different rate design, focused on peak demand reduction, or incorporating a time of use rate for customers with time of use meters could displace system peak emissions.

Program Evaluation – (available results and assessments) The Natural Resources Defense Council (NRDC) issued a report in August 2001 discussing energy efficiency initiatives in California in response to potential supply shortages and market efficiency problems. The report states that the CA PUC estimates between 8 and 12 percent reduction in weather adjusted peaks for the months of May, June and July from the previous year. The NRDC report attributes this peak load reduction in large part to the combined effect of a variety of energy efficiency policies in the state.

Key Issues

One of the most significant issue pertaining to this policy is the political will necessary to execute a change from decades of rate design. For the past several decades residential customers have paid either a flat rate for all kilowatthours they use, or in some cases a rate that declines at higher levels of usage. The inverted rate design adopted in California aligns rate design with the public policy of reducing overall electricity consumption and using electricity more efficiently.

Development of an inverted rate design may be more complex for commercial customers as many of them are billed based on their highest consumption in a given hour as well as on the total amount they consume or the amount they consume at different hours in the day.

This program will work in conjunction with the Governor's 20/20 program that will reward customers who reduce their overall electric consumption by 20% for each month during summer 2001.

Sources of Information

CA PUC Decision 01-05-064 on May 15, 2001 The PUC's order is posted on its web site at: http://www.cpuc.ca.gov/Word_Pdf/final_decision/7150.doc

State statute AB1x: AB1X, passed and signed into law on February 1, 2001, adds section 80100-80122 to the California Water Code. It is available by performing a search for the relevant sections of the Water Code at the California legislative information page: http://www.leginfo.ca.gov/

"Energy Efficiency Leadership in a Crisis – How California is Winning" Natural Resources Defense Council. August 2001.

1.5 Load Response - Reserves

Program Description

Program Vehicle – The Independent System Operator of New England (ISO New England) developed a load response program for summer 2001 that would use customer load response as a tool for meeting the control region's reserve obligations. Customers who are able to reduce their electricity consumption by at least 100 kW within 30 minutes of an ISO request receive a payment for their willingness to reduce consumption as well as a payment for actual instances of reduced consumption in response to an ISO request.

Geographic Scope – New England.[11]

Enabling Authority – ISO New England, pursuant to its obligation to preserve system reliability and comply with existing reliability standards.

Program Duration – Summer 2001. Program anticipated to continue in 2002.

Program Goal – To use demand response to maintain electric system reliability following a second contingency loss or voltage reductions during tight capacity periods.[12] Pursuant to rules established by North American Electric Reliability Council (NERC), ISO New England must be able to respond within prescribed time periods to the sudden loss of power supply.[13] In a presentation to air regulators in November 2000 ISO New England explained that New England does not have many smaller units available that can turn on and off quickly in response to sudden interruptions in supply, for example due to the sudden failure of a generating unit. ISO New England would like to have "push

[11] While the summer 2001 program was open to customers throughout New England, there were not participants from every state.

[12] NEPOOL Operating Procedure No. 8 defines Second Contingency Loss as the largest capability outage (MW) that would result from the loss of a single element after allowing for the First Contingency Loss.

[13] The Northeast Power Coordinating Council reliability requirements require that ISO must be able to restore half of the loss of its second largest supply source within 30 minutes of the loss of that source.

button control" over load response resources that could be relied upon during contingencies and voltage reduction.

Program Implementation

Implementing Agencies – ISO New England

Organization Providing Service – Any Participant of the New England Power Pool (NEPOOL), not just the Participant that supplies electricity to the customer, may sign up a retail customer to participate in the load response program. Retail customers must be able to reduce their electricity demand in thirty minutes or less. Customers may use a variety of mechanisms to reduce electricity demand including load management and/or the use of on-site generation. Individual customers must work through a NEPOOL Participant.[14]

Administrative Complexity – Medium. Program initiation is complex as it requires coordination among ISO, NEPOOL Participants, and individual customers, regulators and other stakeholders. In addition, some of the customers who participated in the program in summer 2001 found the program excessively administratively complex. ISO is contemplating certain program improvements to address the administrative concerns including incorporating a more "low tech" communications protocol, decreasing the amount of time that a customer must be available for interruption, and setting a minimum amount of time that a customer would be guaranteed payment in order to increase certainty for the customers.[15]

Feasibility – Medium. This program was initially developed by ISO New England, but was shaped significantly by the committee process of the New England Power Pool. NEPOOL is an organization of market participants (including transmission owners, generators, suppliers, municipal electric companies, and end users) who make decisions regarding the structure and operation of electricity markets through a committee voting process. While many NEPOOL participants recognized the usefulness of using load response to meet reserve requirements, ISO New England encountered some opposition to this program from generators whose position in the market could be affected by load response activities. Other areas of contention included what the level of payment should be, how the load response programs should interact with the wholesale market, who should bear the costs of the program.

Early results from the program indicate that the participation in the program was lower than ISO New England hoped and anticipated. ISO New England is working to revise the program for summer 2002, and numerous program details remain to be worked out. The program will again move through the NEPOOL Committee process, with the likelihood that many of the same issues will arise again. Customers perceive some

[14] A NEPOOL Participant is an entity, or group of entities, that is signatory to the NEPOOL Agreement and have satisfied certain requirements. For more information see NEPOOL's Market Rules and Procedures.

[15] These improvements have been discussed in ISO New England presentation to the NEPOOL Markets Committee, October 30, 2001 and November 20, 2001.

significant disincentives to participating in the program. For example, specific requirements for real-time Internet communication devices were a deterrent to customers who preferred alternative communication forms such as pager or fax notification.

Input to Program Development – ISO New England developed the program with input from NEPOOL Participants. The program was primarily presented to NEPOOL Participants in the context of a committee voting procedure rather than in the context of a working group, providing little opportunity for collaborative work (see also discussion above on feasibility). ISO New England provided information on the program design to economic and environmental regulators. Some public utility commission representatives attended meetings of the NEPOOL Market Committee during discussion of the load response program.[16] There was limited if any opportunity for non-NEPOOL members to participate in the development of this program. As a result, the program design reflects a compromise among different, often competing, financial interests. There was no opportunity for the Public to participate in the development of this program.

Program Assessment

Costs and Benefits – ISO New England anticipates that using load response (including customer-site distributed generation) to meet reserve obligations would reduce net air emissions associated with meeting the obligations. ISO New England states that relying on customer-site generation and load reduction to cover reserve requirements can result in environmental benefits as it enables ISO to dispatch the system in a more optimal fashion. In particular, if retail customers are standing by, ready to reduce their consumption of electricity from the grid within a short time, ISO does not have to run large generating units at low operating levels just to ensure needed supply in the unlikely event of a the failure of a large generating unit or when voltage reduction occurs because of tight capacity. ISO New England projects that retail customers who participate in this program would be called upon only infrequently because second contingencies and voltage reduction occur relatively infrequently.[17] To participate in the program, customers must install specific software and communications devices. The cost of these devices is approximately $2,500, and there is a charge of $100/month. The New England Power Pool has agreed to distribute the cost of the first 1,000 installations throughout the region. ISO projected total production cost savings of at least $17 million from a 300 MW program ($7 million ozone season, $10 million non-ozone season).

Emission Reduction Potential by Pollutant – (annual and program lifetime) In a presentation to environmental regulators in November 2000, ISO New England estimated economic and emissions savings from the use of load response to cover certain reserve requirements. ISO New England projected the following avoided emissions for having 300 MW of load response ready to meet reserve requirements:

[16] Final decisions of NEPOOL are made by the Participants Committee, where all NEPOOL Members have a voting share. The Markets Committee is one of the Technical Committees that makes recommendations, by taking votes, to the Participants Committee.

[1717] ISO New England presentations to New England Air Regulators, November 30, 2000

Table 3: ISO New England Projections of Emission Reductions From Load Response Reserves Program

Scenario	300 MW (tons reduced)	600 MW (tons reduced)
NOx	390	746
SO2[18]	88	182
CO2	268,000	535,000

Note: ISO New England's projections do not include emissions from operation of distributed generation

Synapse Energy Economics has not reviewed the modeling assumptions and methods that ISO New England used in making these estimates; we include them for illustrative purposes. However, it is important to note that ISO New England did not include any estimate of emissions from distributed generation units that would be used in the load response program because it anticipated that such use would be infrequent.[19] This omission fails to acknowledge the potential impacts from distributed generation due to their high emission rates and potential location in populated areas.

A simple calculation for the 300 MW sensitivity case, based upon data that ISO New England presented for 1998-2000, indicates the potential magnitude of emissions from this load response program.[20] ISO data indicated that the average number of contingencies over 500 MW for the past three years is a little over 9. It is in response to this type of contingency that the load response program would be implemented. To estimate potential emissions based on past history we assume that the load response reserves program would be triggered nine times in a year. Further, we assume that during each event, the load response program would be activated for 2 hours. This assumption is based on the current NEPOOL proposal for guaranteeing end use customers a minimum of 2 hours interruption. Finally, we assume that 2/3 of the load response comes from diesel generation. This assumption is based on ISO New England's projections for summer 2001. These assumptions lead to the following estimate of annual emissions from distributed generation in a 300 MW load response program: 3,072 tons CO2, 58 tons NOx, 5 tons SO2. These emissions would offset any emission reductions from the reserves program.

Potential emission reductions from this programs would be highly case-specific, depending on system dispatch to meet reserve requirements, which is highly dependent on the availability of quick start generation capacity. New England has less quick start generation available than is available in New York and in the Pennsylvania-New Jersey-Maryland Interconnection (PJM or PJM Interconnection). Because of the complexities of system dispatch, the results of ISO New England's analysis cannot be extrapolated to

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[18] ISO New England projects a 26 ton increase in Ozone Season SO2 emissions in the 300 MW case, and an 83 ton increase in ozone season SO2 emissions for the 600 MW case. Mark Babula presentation to New England Air Regulators, November 30, 1001.

[19] ISO New England presentations to New England Air Regulators, November 2000.

[20] For potential emission impacts of the use of customer site distributed generation in an economic load response program, see the section on "Load Response – Economic Programs."

determine ISO New England's projection of emission reductions per megawatt of load response capacity.

Program Evaluation – (available results and assessments). Actual program results were very minimal. Only 18 customers signed up for a total of 6.8 MW. The customers were called upon once briefly reduce load on August 9, when a total of less than one megawatthour was reduced. Payments to those customers for their reserve availability totaled $48,790. ISO New England has hired a consultant to evaluate the results of the program. The review is underway and is anticipated for public disclosure in early November. ISO must share the names of the companies participating in this program with environmental agencies and must identify the type of generator(s) that will be used by customers in the load response program. The Federal Energy Regulatory Commission (FERC) has required that ISO New England submit a compliance report every six months on its load response programs.[21]

Key Issues

The role of market participants in the development of the program is a significant factor to consider in development of subsequent or similar programs. In New England, market participants whose market position can be affected by a load response program are able to shape the program through the voting process. As a result, the program design may reflect a compromise position among a variety of competing interests rather than a sound coherent program to implement an identified goal. In the future, due to FERC's decision that market participants should serve an advisory role rather than a decision-making role, it may be possible to have a more fluid and constructive process for gathering input.[22]

The program represented an important opportunity to gain experience in interacting with customers on a load response program. Since this sort of program is new, there are numerous details to be worked out so that customers are willing to participate, and so that the program is appealing to the customer, and useful to the ISO for its reserve value.

Environmental and utility (or economic) regulators should have regular opportunities to learn about, and provide input to, the development of a load response program. In some instances, regulators will have expertise that ISO staff does not. For example, ISO staff in New England were not familiar with environmental policy goals, programs, and regulations that pertained to, and were affected by load response initiatives.

Sources of Information

Numerous documents are available on ISO New England's website at http://www.iso-ne.com Documents include:

ISO New England presentation to air regulators November 30, 2000.

[21] *ISO New England*, 97 FERC 61,090 (2001), October 25, 2001. ISO New England submitted its first report on December 3, 2001.

[22] FERC Order, July 12, 2001 Dockets RTO1-86-000, RTO1-94-000

NEPOOL filings (March 19, 2001, June 2001)

FERC Orders issued May 18 - 95 FERC ¶ 61,250, October 25, 2001 97 FERC 61,090.

Most recent NEPOOL load response filing (December 31, 2001

NEPOOL rules, markets committee materials available on ISO New England website: http://www.iso-ne.com

1.6 Load Response – Economic Programs

Program Description

Program Vehicle – The ISOs in New York, PJM Interconnection, and New England have developed economic load response programs for summer 2001 that would provide incentives for customers to reduce their electricity consumption in response to market price signals. Customers may use a variety of mechanisms to reduce electricity demand including load management and/or the use of on-site generation.

Geographic Scope – Includes CT, DE, MA, MD, ME, NH, NY, PA, RI, VT.

Enabling Authority– ISOs have undertaken load response as part of their obligation to run power systems in a reliable and efficient fashion. The Federal Energy Regulatory Commission has directed the ISOs to develop load response programs.

Program Duration – Summer 2001. Programs anticipated to continue in 2002.

Program Goal – To create demand elasticity, which is a necessary component of efficient electricity markets. The programs would provide a minimum level of load response activity that could mitigate generator market power and could serve as a platform for more market-based load response.

Program Implementation

Implementing Agencies – ISO New York, PJM ISO, and ISO New England.

Organization Providing Service – Retail customers who are able to reduce their electricity consumption at peak pricing times work with competitive electricity suppliers and utilities.

Administrative Complexity – Medium. Program initiation is complex, as it requires coordination among ISOs, load serving entities, individual customers, regulators and other stakeholders. Developing a load response program requires significant details to be addressed pertaining to wholesale market design and operation, metering and billing issues, and cost causation and recovery. These issues are contentious and often pit market participants against each other. Program modifications proposed for 2002 reflect experience gained in summer 2001 and in some instances reflect an effort to make the programs less administratively complex. For example, ISO New England is contemplating more “low tech” communications options as well as an option that would permit aggregation of smaller customer load response resources.

Feasibility – Medium. Hurdles to developing effective load response arise primarily from the complexity of integrating load response into markets (e.g. metering, communications, and billing issues) as well as from opposition to ISO load response efforts from entities that favor market-based load response and/or benefit from inelastic demand in electricity markets. As discussed in more detail below, market participants whose competitive position could be affected by load response programs had a significant voice in shaping the load response programs. In PJM there was not sufficient support among market participants to pass the program so the ISO filed the program on its own. In New England market participant voting resulted in certain program aspects that reflected concessions to certain market participants rather than a coherent program. Early results from the programs indicate that the participation was lower than proponents hoped and anticipated. Numerous program details remain to be worked out.

Input to Program Development – The three ISOs developed the economic load response programs with input from market participants in the three control regions. The three processes were somewhat different. In New York the ISO established a Price Responsive Load Working Group (PRLWG) that met regularly to develop the program with the assistance of consultants. This format for market participant input is appealing because it provided an opportunity for a variety of market participants to work together in a constructive process to work out differences, gather information and understanding, and work out program details. Environmentalists attribute the prohibition on the use of diesel-fuel fired distributed generation to the close working relationship among market participants PRLWG.

Program Assessment

Costs and Benefits – (budget levels, sources and types of funding, environmental and public health benefits). Economic load response, where customers modify their electricity consumption in response to peak prices, is now widely recognized as an essential component of competitive electricity markets. Load response from some customers can reduce market prices during peak hours resulting in savings for all electricity consumers, not just those that participate in load response activities. Load response can also minimize opportunities for generators to exercise market power, resulting in benefits to all customers due to more efficient wholesale electricity markets. Load response can enhance system reliability by enabling customers to respond to peak prices driven by tight capacity conditions. To date, load response programs appear quite cost-effective as expenditures on load response programs have been much lower than the economic benefits that they produce throughout an electrical control region.[23] As additional programs are developed and reviewed, there will be a greater foundation upon which to evaluated the cost-effectiveness of load response programs.

Load response programs do create a threat of increased emissions associated with the increased operation of highly polluting customer site diesel distributed generation. Efforts are currently under way in certain ISOs (e.g. New York), as well as among

[23] See, e.g. presentation to NY Price Responsive Load Working Group, Neenan Associates, December 6, 2001.

environmental regulators, to reduce the potential for increased emissions associated with economic load response programs.

Emission Reduction Potential by Pollutant – (annual and program lifetime)

It is difficult to determine the potential net environmental impacts of load response programs. The environmental implications of load response programs are complex, difficult to evaluate, and not yet well understood. For example, load response programs could create significant new incentives to operate existing highly polluting customer-sited generation, and defective program designs could make certain low or no-polluting load response options ineligible for participation. Alternatively, the increasing interest in load response could provide a useful long run push for niche applications of clean or renewable fueled distributed generation and environmentally beneficial innovations in load management and energy efficiency. Finally, use of load to meet peak demand might avoid emissions associated with large generating unit ramp up and ramp down.

Evaluations to date of the likely environmental impacts of emergency and economic load response programs are quite rudimentary. A direct comparison of emissions rates between existing customer-sited generation and central generating stations generally indicates that customer-sited generation is substantially dirtier. It is critical to supplement the initial analysis with more detailed analysis that includes specific evaluation of load response for economic, emergency, and reserves purposes in order to understand the potential interaction of load response with operation of the electrical system.

Program Evaluation – (available results and assessments). ISO New England has hired a consultant to evaluate the results of the program. ISO New England's initial review is available on its website, and summary information is in a recent status report to FERC(see Sources of Information, below). A more extensive review, including an assessment of environmental impacts is still underway. Similarly, NY ISO has hired a consultant to evaluate the program in New York. The NY ISO Price Responsive Load Working Group has received numerous documents and briefing materials regarding the evaluation of the price responsive load response program in New York.

Key Issues

There are many key issues associated with the development of effective load response that is consistent with both economic and environmental policy goals.

The role of market participants in the development of the program is a significant factor to consider in development of subsequent or similar programs. In all three regions, market participants whose market position can be affected by a load response program are able to shape the program through the voting process. For example, in New England the Participants voted to restrict the circumstances under which the economic load response program could be in effect and in PJM the Members voted to restrict eligibility to customers with flat load profiles. As a result, the program design may reflect a compromise position among a variety of competing interests rather than a sound coherent program to implement an identified goal. This seems to have happened more in PJM and

New England than in New York. However, each program reflects certain elements that represent a concession to the complexities of achieving agreement among competing market participants, rather than rational elements of load response program design. In the future, due to the Federal Energy Regulatory Commission's decision that market participants should serve an advisory role rather than a decision-making role, it may be possible to have a more fluid and constructive process for gathering input.[24]

The programs represented an important opportunity to gain experience in interacting with customers on a load response program. Since this sort of program is new, there are numerous details to be worked out so that customers are willing to participate, and so that the program is appealing to the customer, and useful to the ISO for its reserve value. Each region is currently contemplating changes to the programs. Several of the changes are designed to make the programs more accessible to consumers and to recognize the unique characteristics of load response that warrant treatment different from the treatment of traditional generating resources.

Environmental impacts of load response programs are poorly understood. Evaluations from summer 2001 should provide some useful basis for additional improvements in the programs. Environmental and utility (or economic) regulators should have regular opportunities to learn about, and provide input to, the development of a load response program. In some instances, regulators will have expertise that ISO staff does not. For example, ISO staff in New England were not familiar with environmental policy goals, programs, and regulations that pertained to, and were affected by load response initiatives. Some of the regions are contemplating changes that will make it easier for low or non-polluting resources to participate. For example, both New York and New England are exploring opportunities for the aggregation of small customers.

Additional environmental issues arise due to the restriction in New York preventing the use of diesel generation for load response, and the lack of such restriction in New England and PJM. The difficulty of including such a restriction points to the importance of appropriate environmental regulation of small-scale distributed generation. With the current push for load responsiveness in electricity markets, such regulations are critical.

Sources of Information

ISO New England presentation to air regulators November 6, 2000.

Numerous documents are available on ISO New England's website at http://www.iso-ne.com Documents include:

NEPOOL filings (March 19, 2001, June 18, 2001, December 31, 2001)

ISO New England Compliance Report, Docket ER01-3086-000, December 3, 2001

FERC Order issued May 18 - 95 FERC ¶ 61,250

NEPOOL rules, markets committee materials: http://www.iso-ne.com

[24] FERC Order, July 12, 2001 Docket RTO1-86-000 and Docket RTO1-94-000.

Numerous documents are available on NY ISO's website at http://www.nyiso.com

Numerous documents are available on PJM's website at http://www.pjm.com

2. Low Emission Generation – Renewables

The second category of energy policies that affect air emissions relates to the support of renewable energy. These policies are: SBC funding of renewable energy projects, renewables portfolio standards (RPSs) and energy purchasing requirements. SBC funding represents the traditional subsidy approach to renewables support, while RPSs and purchasing requirements utilize a "market pull" strategy to enhance demand and support the market price of renewable energy. With SBC funding, subsidies reduce the up-front cost of renewable projects to project developers, making more projects attractive to developers. An RPS requires retail electricity suppliers to sell some minimum amount of renewable energy, and a purchasing requirement places a similar obligation on energy users – usually government accounts. The discussion below focuses on key program design and evaluation issues. When they are well planned and implemented, these policies are not redundant; they are complementary components of an effective renewables support program. The discussion below focuses on key design and evaluation issues.

2.1 System Benefits Charges Supporting Renewables

Program Description

Program Vehicle – A per-kWh surcharge is collected on electricity sales and a portion of the resulting revenues are distributed to new renewable energy projects. (This mechanism is also commonly used to fund energy efficiency programs, and this is discussed in Section 1.1.)

Geographic Scope – The extant SBCs are state mechanisms, applicable statewide. States with programs include: CA, CT, IL, MA, MN, MT, NJ, NM, NY, OH, OR, PA, RI, WI**.**

Enabling Authority – State legislature.

Program Duration – Varies from state to state; generally established for three to ten years with provisions for review at the end of this period.

Program Goal – Designed to reduce the up-front costs of new renewable projects, supporting long-term technology cost reductions.

Program Implementation

Implementing Agencies – The level of the surcharge is set in legislation or by the public utility commission.

Organization Providing Service – Utilities deliver SBC revenues to the PUC or a state technology office or company for distribution to renewable projects. States vary in the organization chosen to distribute the funds. In many states the PUC or a PUC-sponsored collaborative distributes funds. In other states a quasi-public technology development organization or other third-party organization manages the funds, while still other states allow the utilities themselves to manage funds.

Administrative Complexity – Medium to low. If the funds are distributed by an independent (non-governmental) organization, as in Massachusetts and Connecticut, there is minimal work to be done by public administrators. If the PUC distributes the funds, they must issue requests for proposals and conduct a fair and transparent project selection process.

Feasibility – Highly feasible as seen in the number of states (14) with SBC funding for renewables. Many SBCs have been adopted as part of an informal industry restructuring "deal" in which other parties are focused on other issues such as stranded costs, asset divestiture or standard offer/default service. Arguments for renewables subsidies in competitive electricity markets have generally been persuasive, and these subsidies have often been included in the "deal."

Where an SBC proposal is not part of the restructuring process it is likely to encounter more opposition, usually based on concerns over costs. However some SBC funds for renewables have been established outside of restructuring proceedings. Wisconsin's SBC is one example.

Input to Program Development – Most state SBCs are overseen by a board composed of various stakeholders. Boards often include energy regulators, environmental and consumer advocates, representatives of utilities and sometimes environmental regulators. The extent to which the board drives the administration of the SBC differs from state to state. One example of active board oversight is the recent shift in strategy in the disbursement of the Connecticut SBC. While Connecticut Innovations (CI), the organization distributing the funds, originally adopted a private-sector oriented, venture capital model of funds management, CI and the board recently shifted this strategy to one closer to grant making.

Program Assessment

Costs and Benefits – The costs of these programs to consumers depend on the level of the surcharge. In some states (like Delaware) a single SBC supports both energy efficiency programs and renewables with the distribution of funds left to regulators. In other states (like New Jersey) there is a single fund, but the split between efficiency and renewable funding is defined by law. In still other states (like Connecticut) there are two separate SBCs.

Costs to consumers of an SBC program are determined by the level of the charge. For a residential family using a 500 kWhs per month and paying 10 cents per kWh, a one-mill charge would increase monthly bills by $0.50 or one percent. A two-mill charge would increase monthly bills by $1.00 or two percent. Total statewide costs are a function of the level of the charge, the state population and electricity use. Not surprisingly, California's renewable SBC will collect more than any other state's, accounting for over half of national funding (from renewable SBC programs); California will collect at least $135 million per year through 2011.

Program costs are relatively low, especially where SBC funds are distributed by a non-governmental entity.

SBC funds that support renewables clearly provide environmental and technology development benefits, however the benefits of the SBC program as a whole are difficult to quantify. Most states strive to fund a range of technologies, including emerging technologies (closer to the R&D stage) and more mature ones. Thus only a portion of the money distributed goes to projects that provide the direct benefits of zero-emission kWhs, and the number of such projects funded changes year to year. A state could estimate emission reductions and associated health benefits from particular projects receiving SBC funding, as discussed below.

Emission Reduction Potential by Pollutant – SBC funds that support renewables lead to emission reductions through the support of new renewable projects. Funds that support zero-emission technologies will reduce all of the primary electric industry pollutants (SO_2, NO_x, CO_2, and mercury). Funds that support biomass generation may have limited (or no) NO_x reduction value, depending on the NO_x emissions from the new biomass plant.

The air-quality benefits of a renewables SBC program are difficult to quantify without extensive, state-specific research. The area that needs the most research is the state's particular allocation of funds. Most states strive to fund a range of technologies, including emerging technologies (closer to the R&D stage) and more mature ones. Thus, only a portion of the money distributed goes to projects that provide near-term air quality benefits.

With targeted research, however, a state could estimate emission reductions from projects receiving SBC funds. This could be done by obtaining operating data from the projects (or estimating these data), and multiplying kWhs generated by a system marginal emission rate. However, where other subsidies and incentives are available, regulators should take care in concluding that SBC funds are solely responsible for emission reductions. To use the methodology laid out here and claim that the SBC "resulted in" or "achieved" the emission reductions would probably be misleading – especially in the presence of an RPS. A calculation of the cost of emission reductions based only on SBC costs would be equally misleading. Phrases such as "the SBC contributed to" would be more appropriate.

From the perspective of air quality, understanding the air-quality impacts of different potential SBC investments is an important aspect of SBC program implementation. Funding projects employing (a) zero-emission, (b) mature, (c) low-cost renewables will provide the greatest near-term air quality benefits via zero-emission kWhs. Funding other technologies may be highly desirable for other policy reasons, but it may not maximize near-term emission reductions.

With all of the policy goals regarding renewables in mind, regulators should strive to coordinate SBC funding with any other subsidies or incentives for renewables in the state. For example, where an RPS and production tax credit are expected to generate significant wind and landfill gas capacity, regulators might choose to support less "market-ready" technologies with SBC funds. Where other policies are not expected to bring mature renewables on line, regulators may focus SBC funds on these technologies and the air-quality benefits they bring. The role of the SBC vis-à-vis other programs could even be made explicit in a mission statement and/or target ratios for funds spent on different types of project. In short, SBC funds should be targeted with full knowledge of the different air-quality benefits from different types of investment and the likely results of other renewables support programs available in the state.

Program Evaluation – Few states have yet evaluated the administration or effectiveness of SBC funds for renewables. One comprehensive study on a national scale does exist: *Clean Energy Funds: An Overview of State Support for Renewable Energy* (see below). This study is the best available document for those interested in assessing different approaches to the renewables SBC.

Key Issues

Once the level of the SBC has been set, there are three major program design/implementation issues: what generating technologies are eligible; who should manage (distribute) the funds; and how should the funds be targeted?

Wind energy and photovoltaics are eligible to receive funding in all state renewables programs. Beyond these two technologies, states differ considerably in their definitions of eligible technologies. Most states accept some form of biomass generation, with the conditions usually being placed on project emissions or fuel sources (dedicated feedstocks are preferred over waste wood). Hydroelectric energy is often excluded, and where it is eligible, it is usually restricted to small, run-of-river projects. In some states, landfill gas projects are eligible; in others they are not. In some states all fuel cells are eligible, and in other states only fuel cells operating on a renewable fuel are eligible. The UCS and NREL tables cited below (under "Sources of Information") list eligible technologies for every state fund.

As noted, project selection is usually done by the PUC, a collaborative under PUC auspices or a non-governmental entity such as a state technology development organization. Decisions about how funds are managed can have a considerable impact on program results. The collaborative approach is the more traditional one. The collaborative usually includes representatives of utilities, environmental advocates and consumer advocates. The collaborative issues Requests for Proposals (RFPs), reviews proposals and selects projects based on articulated program objectives.

More recently, states have been turning over SBC funds to corporations with an interest and expertise making profitable technology investments. These corporations can put SBC funds to work in ways that PUC-led collaboratives cannot, such as by taking equity positions in renewable projects. The rationale for this approach is based on the desire to increase the effectiveness of each SBC dollar. Renewable projects that generate a high return on investment provide both environmental benefits and financial benefits that can be reinvested in other projects. However this "private-sector" approach has been criticized as focusing on only the few renewable technologies that can produce competitive returns on investment – to the exclusion of less mature technologies that are arguably more in need of public funds.

Finally, regardless of the entity distributing funds, resources can be directed toward certain technologies or types of project. Bolinger et. al. identify three basic approaches to targeting funds:

- ***Investment Model*** – Uses loans, near-equity and equity investments to support renewable energy companies and projects. The first several years of the Connecticut Clean Energy Fund epitomizes this model.
- ***Project Development Model*** – Uses financial incentives such as production incentives and grants to subsidize and stimulate renewable project installation. California is perhaps the best example of this approach.
- ***Industry and Infrastructure Development Model*** – Uses business development grants, marketing support programs, R&D grants, resource assessments, technical assistance, education and demonstration projects to built renewable energy infrastructure. Wisconsin's program is a good example of this approach.

Bolinger et. al. provide useful analysis of these three models.

Sources of Information

At http://eetd.lbl.gov/ea/EMS/EMS_pubs.html#RE, see: "Clean Energy Funds: An Overview of State Support for Renewable Energy."

At http://www.ucsusa.org/index.html, see: "State Renewable Energy Funds."

At http://www.nrel.gov/analysis/emaa, see: "Comparing State Portfolio Standards and System Benefits Charges Under Restructuring."

2.2 Renewable Portfolio Standards

Program Description

Program Vehicle – A Renewable Portfolio Standards (RPS) is a requirement on retail electricity suppliers to sell renewable energy as a certain percentage of their total kWh sales.

Geographic Scope – The extant Renewable Portfolio Standards (RPSs) are state mechanisms, applicable to all retail suppliers selling to customers in the state, however, several federal energy bills have included provisions for a national RPS. States that have adopted RPSs are: AZ, CT, ME, MA, NV, NJ, NM, PA, TX and WI.[25]

Enabling Authority – state legislature.

Program Duration – Most of the state laws providing for RPSs require a review of the program with recommendations after 5 to 10 years. The Arizona RPS, for example, defines an increasing percentage renewables requirement through 2007, but requires a

[25] The RPS in Pennsylvania was established in restructuring settlements with utilities, and it applies to distribution utilities, not competitive retail suppliers.

comprehensive review of the program in 2003, five years after statutory authority for the rule was granted.

Program Goal - The goal of an RPS is to establish a minimum level of dependable demand for the output of renewable generating facilities, ensuring that these resources will play a role in the state's electricity mix and helping projects to obtain financing.

Program Implementation

Implementing Agencies – state energy office and/or public utilities commission

Organization Providing Service – Rather than providing a service or subsidy, the RPS requirement ensures demand for renewable energy. In this sense, retail electricity suppliers provide the "benefit" by purchasing renewable energy to comply with the standard.

Administrative Complexity – High. Retail suppliers' compliance submissions must be verified. In other words, regulators must verify that retailers have actually purchased an amount of renewable electricity equal to the standard. This could be done either by verifying contracts with wholesale suppliers or by establishing a renewable energy credit (REC) trading system. The burden on both regulators and market participants would be lower with a REC system.

Under a REC system, every renewable kWh generated would be accompanied by a tradable credit. The credit and the kWh could be sold separately. Retailers would comply with the rule by purchasing RECs in a quantity equal to the required percentage of their total kWh sales. Regulators would only need to verify that a retailer's RECs were valid and that multiple retailers were not laying claim to the same REC – a verification task that is easily performed in other credit trading systems. The scope of the REC trading system is also significant. A regional program would be more efficient in many ways than multiple state programs.

The Generation Information System (GIS) under development at NEPOOL would provide the informational basis for a New England wide REC system. The GIS system being contemplated, would "tag" all kWhs generated. For compliance, retailers could either submit renewable tags and a figure for total retail sales, or submit the tags associated with all kWhs sold. See the information sources listed below for more on GIS system development. An alternative information system, based on the verification of contract paths, has been proposed in New Jersey and is under consideration by the PJM ISO. Under this proposal, regulators would verify retailer's bilateral contracts (for both renewable energy other energy), and retailers who purchased system power would be allocated a pro-rata portion of the system mix. Whichever of these tracking systems is chosen, it would be clearly more efficient to have the entire Ozone Transport Region using a single system than having states using different systems.

Feasibility – The feasibility of an RPS increases significantly when information is collected that would support a REC system. Without RECs suppliers would have to track the origin of the kWhs they were purchasing – a task that would significantly constrain wholesale energy markets. Feasibility increases further where there is commitment to an energy tracking system at a regional level. This information is most easily tracked at the control area level, so the establishment of regional information systems is preferable by far. The burden of doing this is obviously lower for each regulatory agency when multiple states are involved.

Input to Program Development – The process of RPS rule development is proving to be different from state to state. Some states are commissioning considerable research in the rule development process and taking input from a number of interested parties. Other state agencies are issuing draft rules in fairly streamlined processes.

The rule development process in Massachusetts has been one of the most comprehensive and inclusive in the nation. The Massachusetts energy office put together an RPS advisory board to consisting of retail marketers, generation companies, transmission and distribution companies, environmental advocates, renewable technology trade associations and state regulators and legislators. The energy office also commissioned a study of costs and benefits and a number of white papers focused on complex program design issues. See the links under "Sources of Information."

Program Assessment

Costs and Benefits – Consumers bear the cost of an RPS as retail suppliers pass on to them the costs of purchasing renewables for compliance. Costs will be largely a function of (a) the level of the RPS and (b) the renewable resources available in the region.

One of the most extensive studies of RPS costs and benefits focused at the state level was performed for the Massachusetts energy office. This study assesses the cost of renewable energy, transaction costs and administrative costs for the Massachusetts RPS. The study predicts a range of costs consistent with different implementation decisions. The low end of this range includes total costs of $11.8 million in 2003 and $105.3 million in 2012 (in constant 2002 dollars). The high end of the range includes costs of $15.8 million in 2003 and $110.7 million in 2012.

Researchers at Lawrence Berkeley Labs performed a comprehensive review of the Texas RPS. This study concludes that Texas' is likely to be one of the most effective RPSs in the country. Initial RPS targets in Texas will be far exceeded by the end of 2001, with some 930 MW of capacity slated for installation this year. Costs appear to be quite low, with much of this new wind coming on line for under 3 ¢/kWh (including a 1.7 ¢/kWh federal production tax credit). These numbers underscore the importance of a state's renewable resources in determining RPS costs.

It will be difficult to quantify the benefits of an RPS requirement unambiguously, because we cannot know what portion of the new renewable projects developed in a state would have been developed absent the RPS. (This is especially problematic in states that also subsidize renewables in other ways.) However, one could estimate an upper bound of the benefits by assuming that all projects developed after the establishment of the RPS are the result of the rule.

The Union of Concerned Scientists has also performed detailed analyses of several state and federal RPS proposals. Again, see the papers listed below, under "Information Sources."

Emission Reduction Potential by Pollutant – Assuming that all renewable projects developed in the context of an RPS are the result of the rule, one could either multiply total renewable generation each year by a system marginal emission rate or model the impact of hourly renewable generation using a regional dispatch model. Using the latter approach, consultants to the Massachusetts energy office estimate NO_x reductions from that RPS starting at roughly 0.5 thousand tons in 2003 and rising to nearly 1.2 thousand tons in 2009. Reductions of CO_2 are projected to be over 0.5 million tons in 2003 and over 2.5 million tons in 2009. The report notes that, for pollutants subject to a regional cap and trade program, emission reductions could be eroded by the sale of credits or allowances and increased emissions from other sources.

We estimate emission reductions from an OTC-wide RPS in Chapter III. Our calculation of potential reductions highlights some important RPS design decisions regarding technology eligibility. Most renewable technologies have zero emissions, however landfill gas and biomass generation do emit significant amounts of NO_x. Thus, from the perspective of air emissions, the most effective RPS would not count generation from these sources as eligible. However, most RPSs – having broader goals than just emission reductions – do accept landfill gas and biomass.

Most RPSs address this issue in some way, for example by defining eligible biomass as "sustainable" and/or "low emission." Regulators in Massachusetts have proposed a biomass NOx emission limit in the range of 1.5 to 2.0 lb/MWh. This would allow a number of existing biomass facilities in the region to comply by installing or upgrading NOx controls. (Newly controlled plants would qualify as "new" renewables and would lower the cost of the RPS relative to a scenario in which these plants were not eligible.) However, if one considers that, over the long run, new renewables are likely to be competing with new combined-cycle gas plants, this might not be the best policy from an air perspective, because many eligible biomass plants would result in increased NO_x emissions relative to a new gas plant. This potential is illustrated in our calculation of potential RPS emission reductions, in Chapter III.

Program Evaluation – We are not aware of any studies in which actual RPS program data have been evaluated.

Key Issues

A number of complex issues must be addressed in implementing an RPS. These issues include:

- Should retail suppliers comply as a company or should each product offered have to comply?
- Should the cost of renewable energy be capped to protect consumers from unexpectedly high prices?

- How should compliance be verified, by tracking electricity contracts or through a system of tradeable renewable energy credits? How should renewable energy purchased in other states or regions be treated?
- If a system of renewable credits is created, how should this system interact with existing emission trading systems?

A large body of literature exists regarding these RPS design issues. Rather than reproduce these analyses here, we direct the reader to the original studies, listed below.

Sources of Information

At http://www.state.ma.us/doer/rps, see "Cost Analysis Report" and "White Papers."

At http://www.nrel.gov/analysis/emaa, see "Comparing State Portfolio Standards and System Benefits Charges Under Restructuring."

At http://www.ucsusa.org/index.html, see "State Renewable Portfolio Standards," "Powerful Solutions" and "Clean Energy Blueprint."

At http://www.iso-ne.com/committees/Generation_Information_System, see: "GIS Database Project Description," "GIS Request for Proposals" and "GIS Requirements Definitions Table."

At http://eetd.lbl.gov/ea/EMS/EMS_pubs.html#RE, see: "The Renewables Portfolio Standard in Texas: An Early Assessment."

2.3 State and Local Purchasing Requirements

Program Description

Program Vehicle – A variety of states and localities have developed requirements pertaining to the use of renewable resources and the efficiency of electricity consumption in state buildings. For example, a state or locality mandates that a certain proportion of the state or locality's electricity consumption be supplied by renewable energy sources. Purchasing requirements can vary in the minimum percentage required and in the definition of "renewable".

Geographic Scope – MD and NY have state purchasing requirements. MA legislation required the administration to conduct a feasibility study of a ten percent renewable purchase requirement. A number of cities have also established renewables purchasing requirements including the City of Seattle, City of San Francisco, City of Chicago, and City of Portland (OR).[26]

[26] While these cities are not in the Ozone Transport Region, we have included them in this survey as examples of financing mechanisms for renewable purchasing requirements.

Enabling Authority – State requirements are established through a variety of authorities including state legislation (e.g. MD, MA), Governor's Executive Order (e.g. MD, NY), local voting (e.g. City of San Francisco), and City Ordinance (Seattle).

Program Duration – Requirements are generally established for 3-10 years.

Program Goal –

Maryland: 6% of electricity for state buildings from renewables (no more than 50% from landfill gas), reduce energy use 10% by 2005, 15% by 2010, Energy Star appliances or top 25% of energy efficiency, facilitates purchase of alternative-fuel and low-emission vehicles for state fleet. MD also has a law that requires that use of active and passive solar energy systems be evaluated in its standards for determining building life-cycle costs.

New York: 10% of electricity for state buildings from renewables by 2005, 20% by 2010, also adherence to strict energy efficiency standards in renovation and construction.

Massachusetts: 10% of electricity for state buildings from renewables by 2010.

Pennsylvania: The Governor of Pennsylvania announced the signing of a new contract for the purchase of electricity from renewable resources.[27] The contract covers 100 million kilowatt-hours of electricity, about 5 percent of the state's total usage, over two years beginning Jan. 1, 2002.

Twenty percent of this purchase of green power will be supplied by the new Exelon-Community Energy wind farms in Fayette and Somerset counties. This wind purchase for 2002 and 2003 is equal to the generation from 5 of the wind farm's turbines. Wind power consumes no fuel and produces no emissions.

The remainder of the purchased green power will come from hydroelectric power, a fuel-free energy source; landfill-gas-to-energy generation, which promotes resource recovery and greenhouse gas reduction; and solar-electric generation.

Chicago and 47 other local government bodies joined in issuing an RFP requiring (1) lower costs for members, (2) 20% of power from renewables by 2005, and (3) supplier plans to reduce pollution caused by power they generate.

Portland, Oregon: In 1995, the city signed a 5 year contract with Portland General Electric to take a minimum of 10 MW at wholesale rates, 5% of it to be from wind power. The city used a portion of the savings to fund new renewable projects. Subsequently, in 2000 the city signed contracts with Portland General Electric and Pacific Power to purchase at least $30,000 worth of renewable energy through green pricing programs. The City also has some renewable resources. The City's Office of

[27] "Gov. Schweiker Announces Historic Purchase of Green Power: Action marks fifth anniversary of PA's landmark electric competition program" Press release, December 5, 2001. "PA PUC Chairman Glen Thomas Says PA State Government Leads by Example by Purchasing Green Energy, Shopping for Power" Press release, December 5, 2001 .

Sustainable Development hopes to reach a target of obtaining 100% of the City's electricity from renewable resources by 2010.[28]

San Francisco, California: In November, 2001 city residents approved a $100 million revenue bond that will result in the installation of 40 MW of renewable energy (including 10-12 MW of solar power on city-owned facilities and schools).

Seattle, Washington: A city ordinance (Fall 2001) authorizes Seattle City Light to begin purchasing power from the State Line Wind Generating Plant currently under construction. The utility would acquire the energy generated from 50 megawatts of installed capacity beginning Jan. 1, 2002, increasing to 100 megawatts in August 2002 and possibly to 175 megawatts by August 2004.

Program Implementation

Implementing Agencies – State Agencies, Cities.

Organization Providing Service – Utilities, competitive electricity suppliers.

Administrative Complexity – Medium. The administrative complexity of these purchasing requirements will be affected by the exact nature of the purchase requirement and by the contractual arrangement with the supplier for verification of compliance with the purchase requirement. In a region where there is a Generation Information System (GIS), verification of compliance with purchasing requirements may be facilitated since the state or city, and the supplier can rely on a central, reliable source of data. Otherwise compliance verification may require mechanisms to prove purchases from specific facilities.

Feasibility – Medium. Renewable purchasing requirements appear more feasible to implement when they are part of a larger set of policy goals or are specifically supported by the public. For example, in Maryland, the purchasing requirement will help the state meet the goals of the Chesapeake 2000 Agreement.[29] Portland, Oregon's green power purchasing program is part of a wider effort to meet the goal set in its 1993 CO_2 reduction strategy of establishing 400 MW of new renewable resources by 2010. The City of Portland's purchases are facilitated by reliance on "green tags" issued by the Bonneville Environmental Foundation.[30] San Francisco, 73% of residents approved the revenue bond to support renewables.[31] In contrast, MA has not yet initiated its renewable power purchase. In 1998 the state issued an RFP for green power, but did not receive any offers because more than 95% of the states meters are on the standard offer, which is very

[28] Personal communication with David Tooze, Portland Office of Sustainable Development, January 9, 2002.

[29] The Chesapeake 2000 Agreement is a regional pact that requires aggressive new efforts by States in the mid-Atlantic to redirect land use and conservation policies to reduce release of pollutants into the Chesapeake Bay.

[30] More information available at http://www.bonenvfdn.org/

[31] Energy Information Source, November 7, 2001.

difficult for suppliers to compete against.[32] The state anticipates issuing another RFP in the future; however, budgetary issues may again result in program delays. As the market for renewable generation develops, implementing state purchasing requirements for certain percentages of renewables, or for purchases from specific facilities should become increasingly feasible.

Input to Program – Opportunities for input from stakeholders and the public vary according to the program vehicle. For example, City purchasing requirements are generally part of city policies voted on and supported by residents. State purchase requirements appear to be less informed and directed by the general public as they are established through legislation or executive order of the Governor.

Program Assessment

Costs and Benefits – Programs vary from having a net economic cost to having a net economic benefit (e.g. City of Portland). Analysis performed for state agencies in Massachusetts indicated that over a ten year period, the projected cost premium for requirement that gradually increased to ten percent would be 1.6 percent of the Commonwealth's total electricity bill. This cost premium corresponds to an additional state expenditure of $8,366,000 over ten years.[33] Proponents of the City of Seattle's wind purchase state that "the price for the energy generated in January, including the costs the utility will incur to store the intermittent wind energy and deliver it as a firm energy product, will be less than 5 cents per kilowatt hour and is comparable to costs for electricity generated by natural-gas-powered turbines."[34] City of Portland estimates a net savings of $300,000 per year, which is returned in part to ratepayers and used in part to fund new renewable resources. The City of Portland currently pays premiums of $2.95/100 kWh and $3.50/100 kWh for its renewables purchases from two local utilities.[35] Benefits of these programs include setting an example and serving as a policy leader.

Successful purchases can also provide a boost to the market for renewable power. For example, Chicago's purchase (with other local governments) of 80 MW of renewables would be the largest purchase in the nation to date by a non-utility customer.[36] Programs that focus specifically on new renewables are likely to provide a net increase in installed

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[32] Personal communication with Jonathan Goldberg, MA Executive Office of Administration and Finance, Operational Services Division, December 3, 2001.

[33] "Commonwealth Renewable Energy Procurement: A Report to the General Court on the Viability, Effectiveness, and Cost of Minimum Renewable Energy Purchases by State Agencies," Executive Office of Administration and Finance (Operational Services Division) Office of Consumer Affairs (Division of Energy Resources), Draft Report, December 2001. Emphasis added.

[34] "Mayor Paul Schell Proposes Nation's Largest Purchase of Wind Power," City of Seattle press release, September 17, 2001

[35] Personal communication with David Tooze, Portland Office of Sustainable Development, January 9, 2002.

[36] See Data Base of State Incentives for Renewable Energy. www.dsireusa.org

renewable resources, whereas programs that permit reliance on existing renewable resources may support the continued viability of existing resources but may not have an incremental impact on the fraction of renewables in the resource mix.

Emission Reduction Potential by Pollutant – Medium to High. The effectiveness of these policies in achieving emissions reductions will depend on how the purchase requirement is designed and implemented. For example, a requirement that focuses on new renewables, and renewables that are incremental to any state renewable portfolio standards can result in the addition of new renewables (beyond those that already exist or are required) to the electric system. A recent draft report to the Massachusetts Legislature concludes that, "although viable, a mandate to procure ten percent of electricity for use at state facilities *from existing renewable sources* would not be an effective means of promoting new growth in the renewable power industry."[37]

In contrast, the report concludes that a state renewable energy procurement policy, structured to emphasize *new* renewable sources, would significantly benefit renewable energy providers in the region by providing incentives for the financing and development of new renewable energy projects.

Program Evaluation – The MD Energy Administration estimates that requirements to include solar energy systems in life cycle costing has not had a large impact on the use of solar energy in Maryland.[38] A recent draft report to the Massachusetts Legislature from state agencies in Massachusetts provides an analysis of the viability and impacts of a ten percent existing renewable purchase and a ten percent new renewable purchase.[39]

Key Issues

Definition of renewables: State and local purchasing requirements will be most effective in adding incremental resources when the requirements are designed in a fashion that does not simply rely upon the existing stock of renewable resources.

Financing vehicle: Several of the cities have included innovative financing mechanisms in the design of their purchase requirement, such as bonds, and combinations between renewable and traditional sources of power. In addition, Chicago's joining together with dozens of other local governments provides bargaining power and visibility to their effort.

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[37] "Commonwealth Renewable Energy Procurement: A Report to the General Court on the Viability, Effectiveness, and Cost of Minimum Renewable Energy Purchases by State Agencies," Executive Office of Administration and Finance (Operational Services Division) Office of Consumer Affairs (Division of Energy Resources), Draft Report, December 2001. Final anticipated early 2002.

[38] See www.dsireusa.org

[39] "Commonwealth Renewable Energy Procurement: A Report to the General Court on the Viability, Effectiveness, and Cost of Minimum Renewable Energy Purchases by State Agencies," Executive Office of Administration and Finance (Operational Services Division) Office of Consumer Affairs (Division of Energy Resources), Draft Report, December 2001. Final anticipated early 2002.

A renewable purchasing requirement can present certain budgetary issues since there is sometimes an incremental cost for satisfying a minimum percentage of renewables purchasing requirements. In some cases the incremental cost can be offset with savings from other components of the contract for the renewable purchase. Some cities have adopted innovative financing mechanisms to facilitate complying with the purchasing requirement. States and cities implementing purchasing requirements should consider how the purchasing requirement will be funded. Broad public support, and consistency with broad policy goals increase the likelihood of success from a purchasing requirement.

Sources of Information

MD purchasing requirement: Executive Order 01.01.2001.02, available at: http://www.gov.state.md.us/gov/execords/2001/html/0002eo.html

MD life cycle costing: 1990 House Bill 1405, http://www.energy.state.md.us

MD Energy Administration, 410-260-7539

"Commonwealth Renewable Energy Procurement: A Report to the General Court on the Viability, Effectiveness, and Cost of Minimum Renewable Energy Purchases by State Agencies," Executive Office of Administration and Finance (Operational Services Division) Office of Consumer Affairs (Division of Energy Resources), Draft Report, December 2001. Final report anticipated early 2002.

Chicago et al: Chicago Department of Environment, http://www.ci.chi.il.us/Environment

Portland Office of Sustainable Development: http://sustainableportland.org

City of Seattle: http://www.ci.seattle.wa.us/light/news/newsreleases/

Other information on Green Purchasing and Aggregation available at DSIRE Website. http://www.dsireusa.org/

3. Air Quality Policies – Power System Emission Reductions

Unlike the energy policies explored above, the third category of policies we address focuses more directly on emissions from electric generators. These policies are:

- Emission Performance Standards (EPSs),
- multi-pollutant, output-based emissions standards for high emission sources,
- output-based allocations for high emission sources in a cap and trade program,
- NOx Budget Allocation Schemes,
- emission standards for distributed generation,
- and mandatory information disclosure.

With the exception of information disclosure, all of these policies are implemented by air regulators. Many of these policies, including the multi-pollutant and output-based approaches to emission regulation, reflect an evolution in the thinking of air regulators. This evolution is toward programs that force sources to develop integrated strategies, focusing on a broad array of pollutants and that reward more efficient units with output-based standards and allocation schemes. Other policies explored here are designed to address new issues emerging as a result of advancing technology (emission standards for distributed generation) and industry restructuring (information disclosure).

3.1 Emission Performance Standards

Program Description

Program Vehicle – An Emission Performance Standard (EPS) is a requirement that all retail electricity suppliers in a state maintain an electricity portfolio that meets weighted average emission standards. In other words, when the emission rates associated with all the electricity a retailer purchases are averaged (weighted by the amount of each purchase), this average must be at or below the standard.[40]

Geographic Scope – statewide. States with the statutory authority to establish an EPS are CT, MA and NJ.

Enabling Authority – state legislature. Note that two of the three state laws that allow for EPSs make the standard contingent upon a finding of fact or action by other states.

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[40] This policy mechanism has often been referred to as a "Generation Performance Standard" (GPS), and this has created confusion, as there are several proposals at the federal level for policies called GPSs. Under these policies, the national NOx, SO_2, CO_2 (and in some proposals mercury) emissions from electricity generation would be capped. Allowances allocated to generating companies would be based on each company's expected generation multiplied by the nationwide GPS emission rates for these pollutants. An example of a federal GPS proposal is found in Senator Jeffords' bill, S. 1369. In an effort to distinguish the state-level proposals from these federal proposals, many have begun using the EPS term to describe state-level emission standards placed on retail electricity suppliers.

- In Massachusetts, an EPS for at least one pollutant is to be in place by May 1, 2003, "unless three or more other northeastern states enact similar standards before that date," in which case the Department of Environmental Protection (DEP) may adopt the EPS prior to May 1, 2003.
- In Connecticut, the restructuring law gave the DEP a date certain to establish an EPS, but it will not go into effect until "three or more of the states participating in the northeastern states' Ozone Transport Commission as of July 1, 1997, with a total population of not less than twenty-seven million at that time, have adopted such standard." This provision basically assumes that New York State adopt an EPS before the Connecticut EPS could go into effect.
- New Jersey's restructuring law gives the state DEP the authority to promulgate an EPS if it becomes apparent that federal efforts (like the NOx SIP Call and Section 126 petitions) fail to protect the state from pollution transported from upwind states. The law *requires* the DEP to promulgate an EPS if other states, representing 40 percent of the load in the PJM Interconnection, adopt an EPS. Currently no other states in PJM are considering one.

These population-based triggers reflect the fact that an EPS established by only one state may be ineffective at preventing increased generation at upwind power plants, as retailers serving customers in other states purchase from companies with high-emitting units. Population triggers also ensure that a critical market size is realized to prevent price spikes that could occur if, for example, only one state implemented an EPS.

Program Duration – No EPSs have been established. As an addition to a state's existing emission standards, one would not expect EPSs to be subject to sunset clauses.

Program Goal – The idea for an EPS emerged in the restructuring process. The concern was that competitive retail suppliers would purchase electricity to serve customers in northeastern states from high emitting facilities outside of the Northeast and that the emissions from these facilities would adversely affect the Northeast. The goal of an EPS would be to prevent retail suppliers from importing large amounts of high-emission generation into states with stringent emission regulations.

Program Implementation

Implementing Agencies – State environmental agency

Organization Providing Service – Notably, because a state does not have jurisdiction over generating companies in other states, the requirement is placed on the entity over which the state does have jurisdiction – the retail electricity supplier.

Administrative Complexity – High. As with a Renewable Portfolio Standard, regulators would have to verify the weighted average emission rates of suppliers' portfolios. This could be a highly resource intensive process. A regional Generation Information System (GIS) is under development, which could significantly lower the costs of EPS compliance verification. The envisioned GIS would "tag" every kWh of generation in the region with a certificate recording the various emission rates of the unit (NO_x, SO_2, CO_2, mercury). Retail suppliers would calculate their weighted average emission rates using these certificates. See GIS documents cited below. As discussed above, an alternative information system, based on the verification of contract paths, has been proposed in New Jersey and is under consideration by the PJM ISO. A copy of this proposal is available from the New Jersey Department of Environmental Protection. A regional information tracking system (or systems) is extremely important to the implementation of an EPS; in regions where a regional information system is not established, the administrative burden of an EPS would be extremely high.

Feasibility – There is considerable uncertainty over whether any state will adopt an EPS. In order to move forward, Connecticut would need EPSs in several states, with a combined population equal to or greater than that of New York. Air regulators in New Jersey are not actively considering an EPS, and this leaves only Massachusetts. It is not clear whether Massachusetts regulators would move to become the only state in the region with an EPS. The feasibility of implementing an EPS will increase substantially if a regional GIS is developed, providing a regional data tracking system regulators could use to verify compliance. For more on a GIS, see the GIS link below and the Summary and Recommendations section of this report.

Input to Program Development – Air regulators in Connecticut and Massachusetts have begun work drafting EPS rules. The draft rule in Connecticut is expected this winter. Connecticut's rule drafting efforts followed the routine path used for regulatory efforts, involving the SIPRAC subcommittee process, which included participation by all affected stakeholders. The Northeast States for Coordinated Air Use Management (NESCAUM) also released a model EPS rule, and two public meetings were convened to discuss a draft of the model rule.

Program Assessment

Costs and Benefits – No analyses of costs or benefits of an EPS are available. One factor that would make program costs difficult to assess is the fact that a large portion of these costs – the costs associated with the GIS system – would be shared across several programs (RPS, disclosure and EPS). Allocating costs to programs would be somewhat arbitrary.

The benefits of an EPS are also difficult to estimate. As many analysts have pointed out, the benefits – in terms of reduced air emissions – are dependent on the size of the region implementing the policy. For example, if only one northeastern state established an EPS, high-emitting generating units in the region would still have ample markets in which to sell their output, and emission reductions would likely be minimal.

Emission Reduction Potential by Pollutant – One could estimate an upper bound of the potential emission reductions from a region-wide EPS by assuming that regional average emissions were reduced from current levels to the EPS levels. Emission reductions could be significantly smaller than this, as some high-emitting generators might maintain high output levels by selling energy to retailers outside the EPS region. In Section III, we calculate potential emission reductions from an OTC-wide EPS, using this methodology.

Program Evaluation – Currently no EPS standards are in effect.

Key Issues

Because EPSs and RPSs both regulate the portfolios of retail suppliers, the two standards share some of the same design issues, including:

- Should retail suppliers comply as a company or should each product offered have to comply?
- How should compliance be verified, by tracking electricity contracts or through a system of tradeable energy credits?

In their work, the GIS working group will consider the information needs of a state EPS and weigh these needs against incremental costs. Most importantly, for an EPS, *all* energy would have to generate a tradable tag – not just renewable energy.

Sources of Information

At http://www.nescaum.org/workgroups/energy.html, see "Model EPS Rule"

At http://www.iso-ne.com/committees/Generation_Information_System, see: "GIS Database Project Description," "GIS Request for Proposals" and "GIS Requirements Definitions Table."

3.2 Multi-pollutant Output Based Emissions Standards Targeting High Emission Sources

Program Description

Program Vehicle – Massachusetts regulations establish output based emissions standards for emissions of SO_2, NO_x, and CO_2 from certain highly polluting electricity generators. The program is a targeted program in addition to the state's implementation of a NO_x cap and trade system. The Massachusetts Department of Environmental Protection reserved sections for CO and PM 2.5; however, the DEP has not set a schedule for developing standards for those pollutants.

Geographic Scope – Massachusetts

Enabling Authority – General statutory authority. Regulation contained in 310 CMR 7.29

Program Duration – Emission control plan must be submitted by January 1, 2002. Emissions standards take effect as early as October, 2004, or may take effect in October 2006. Emissions limits are annual rather than seasonal.

Program Goal – Lower emissions of harmful pollutants from largest, oldest, and least efficient power plants in order to further protect public health and the environment and to address local air quality concerns.[41] The purpose of the regulation is to control emissions

[41] Background Document and Technical Support for Public Hearings on Proposed Amendments to 310 CMR 7.29 et seq., June 2000, at 12.

of nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), carbon monoxide (CO), carbon dioxide (CO_2), and fine particulate matter (PM 2.5) from affected facilities in Massachusetts. The department will establish mercury standard following study and analysis. Sections for CO and PM 2.5 are reserved. Output based standards reward efficient electricity generation.

Program Implementation

Implementing Agencies – Massachusetts Department of Environmental Protection. Other agencies participated in the development of this regulation by attending meetings and providing comments. Agencies included Department of Telecommunication and Energy (the public utilities commission) and the Division of Energy Resources (the state energy policy agency).

Organization Providing Service – Affected generators in Massachusetts must comply with this regulation. An affected facility is defined as a facility that emitted greater than 500 tons of SO_2 and 500 tons of NO_x during any of the calendar years 1997, 1998 or 1999 and that includes a unit which is a fossil fuel fired boiler or indirect heat exchanger that: (1) is regulated by 40 CFR Part 72 (the Federal Acid Rain Program); (2) serves a generator with a nameplate capacity of 100 MW or more; (3) was permitted prior to August 7, 1977; and (4) had not subsequently received a Plan Approval pursuant to 310 CMR 7.00: Appendix A or a Permit pursuant to the regulations for Prevention of Significant Deterioration, 40 CFR Part 52, prior to October 31, 1998.

Administrative Complexity – Low. These regulations include multiple features that could affect administrative complexity: they are multi-pollutant, they are output based, and they focus on a subset of generation sources in the state. We discuss each of these feature separately. However, overall the administrative complexity of these regulations is low. The multi-pollutant aspect introduces significant administrative efficiency for both the affected facilities and the implementing agency. The multi-pollutant approach enables the consolidation of compliance planning, measurement, reporting, and verification activities both for the affected facilities and the agency. This approach also relies on the same output data for all pollutants, which enhances the efficiency and consistency of the program.

Use of an output-based standard does not significantly increase the administrative complexity. An output-based standard requires only net generation data in addition to the emission data that is already routinely reported to the US Environmental Protection Agency (EPA). Net generation data is widely available publicly, and is metered for financial settlement reasons within an electrical control region. If the MA DEP adds requirements pertaining to mercury, there could be additional work. For example, the agency would have to determine how to measure and monitor mercury emissions (e.g. using mercury content of fuel, or monitoring stack emissions,) new measurement verification methods, and would have to develop data substitution and stack testing protocols. Although there are currently no requirements for monitoring, measuring or control mercury, it appears likely that mercury will become a regulated pollutant and the agencies efforts on this front would not be wasted.[42]

The target facilities are higher emitting facilities, and are all required to file with EPA, as such the facilities are all within the scope of existing requirements. The requirements in this regulation represent a requirement in addition to regulatory requirements under existing cap and trade programs, thus they require that affected facilities submit, and the implementing agency review, one additional compliance plan. Thus it would add some additional staff hours for the affected facility and the agency. However, because the regulation relies primarily on data that's compiled for other regulatory purposes, the additional staffing requirements are likely to be small. Any violations of the standard would be in addition to violations of other requirements, so they may require additional enforcement actions that would require agency activity.

Feasibility – Medium to high. At the time this regulation was introduced it was very controversial with strong proponents and strong opponents. Citizens concerned about local air quality impacts were strong proponents (and catalysts) of this regulation. However, the proposed regulation had other proponents as well. With its emphasis on generation efficiency, the output-based regulation split the generation owners who have traditionally been fairly unified in their positions on emission regulation. The output based standard pitted newer lower emission facilities against those facilities that had been grandfathered under other regulatory schemes and were at a qualitatively different emission level. The regulations were developed at a time when there was a general economic and competitive equity issue that needed to be addressed. As a result the benefits of the program were economic as well as environmental, and the program divided what was once a unified community because of the competitive implications of the regulations.

In the past few years there has been a state and national trend toward control of emissions on a multi-pollutant basis, and on an output basis, to capture efficiencies and to assist generation owners with their compliance activities so that they can assess control requirements and options comprehensively. Consequently, regulatory programs such as this are likely to become more and more feasible.

Input to Program Development – The origins of this regulation are in a public petition presented to the Governor of Massachusetts. Over 150 environmental and public health groups (the "Clean Air Now Coalition") submitted a petition for government action in late 1997. The Clean Air Now Coalition petition sought emission reductions from the state's oldest and dirties coal and oil-fired generation facilities. Then Governor Celucci pledged to get the power plants to "meet modern emission standards." The Massachusetts DEP committed to taking some action on the petition. The Department conducted a series of meetings between petitioners, electric companies, and other interested parties (including state agencies). The purpose of the meetings was to identify informational needs and scope out issues. Subsequently the Department issued proposed

[42] See, e.g. STAPPA ALAPCO comparison table of Federal Legislation in Appendix B.

regulations and received more than twelve hundred pages of written comments as well as over twenty-five hours of oral testimony.

Program Assessment

Costs and Benefits – Output based standards encourage generation efficiency. When implemented in the context of a cap and trade emissions program, out-put based standards can ensure reductions from specific facilities in response to local air quality concerns. Multi-pollutant regulations can reduce the total costs of compliance with regulations because of the opportunity for integrated decision making on compliance options. MA DEP anticipates that emission reductions from the electric generating industry, and the affected facilities of this regulation, will reduce air pollution, benefit the environment and be cost-effective. The regulation establishes a regulatory program implementing a comprehensive and integrated emission reduction approach for the largest emitting sources among Massachusetts' electric generating plants. Emission control strategies implemented for compliance will allow for more efficient combustion units and air pollution controls that reduce multi-pollutant emissions in a manner that is technically and economically feasible.[43]

DEP discusses control costs for the various pollutants in comparison to control costs for other sectors. DEP believes that for SO_2, a cost of $400/ton of pollutant removed is reasonable and cost-effective. DEP believes that NOx control costs of $2,000/ton or less represent cost-effective control measures that are more cost-effective and feasible than those available in other sectors. The Department cites research indicating that extending the NO_x SIP Call reductions in the SIP Call region year-round would cost approximately 20 percent more than the seasonal program, but would yield over a billion dollars more in net benefits than the seasonal program. The Department believes that this regulation is the next most cost-effective approach, beyond those steps it has already taken, to make reductions in CO2 from any sector.[44]

The Department will evaluate the cost of mercury controls when is proposes a mercury standard as part of this regulation. MA DEP states that multi-pollutant control strategies that can be implemented for compliance with this rule can result in reduced annualized costs for capital and operating and maintenance compared with single pollutant regulatory programs.[45]

Emission Reduction Potential by Pollutant – High. The regulation establishes annual and monthly caps on emissions.

[43] DEP's Statement of Reasons and Response to Comments, section on Sector Cost Comparison, April 2001, at 18

[44] Id. at 19-24.

[45] Id. at 20-22.

Sulfur dioxide: Rolling annual limit: 3 lbs/MWh. Monthly limit: 6 lbs/MWh. The Department expects to achieve an actual reduction in the aggregate average SO2 emissions rate from all of the affected units of between 50 and 75 percent.[46]

Nitrogen oxides: Rolling annual limit: 1.5 lbs/MWh. Monthly limit: 3 lbs/MWh. The Department expects an approximate 50 percent aggregate reduction in NO_x emissions from the affected facilities from the baseline (average of 1997-1999).[47]

Carbon dioxide and mercury: The Department's standard of 1,800 lbs/MWh represents a 10% reduction from historic baseline (1997-1999). The Department anticipates that significant mercury and carbon dioxide reductions will be required over the next ten years.[48]

Allowances will only be available for use for facilities to reduce their emissions from 6.0 lbs/MWh to 3.0 lbs/MWh.[49] Off-site emissions reductions are allowed for CO_2, subject to DEP approval.

Program Evaluation – The program has not yet been evaluated.

Key Issues

Strong support from certain generation sources and from citizens contributed to success of this regulatory effort. Pressure from citizens groups created a strong political climate for the state of Massachusetts to take some action to reduce emissions from the state's oldest and dirtiest facilities. Support from certain generation sources, and the split among generation sources, facilitated the development of this policy.

Another key issue is the consistency of this policy with developments in the electricity industry and with the state's economic policy of enhanced and efficient competition in the electricity industry. Each aspect of this policy is consistent with the state's restructuring efforts and increased emphasis on ensuring efficient competition in the industry.

Sources of Information

The regulation and technical support documents are available at the following website:

http://www.state.ma.us/dep/bwp/daqc/files/regs/729final.doc

STAPPA/ALAPCO Multi-Pollutant Strategy Components – Comparison of Approaches November 29, 2001, contained in Appendix B of this report.

[46] Id. at 24.

[47] Id. at 23-24.

[48] Id. at 24.

[49] Id. at 18.

3.3 Multi-pollutant Output Based Cap and Trade Program Targeting High Emission Sources

Program Description

Program Vehicle – New Hampshire statute establishes output-based allocations for emissions of SO_2, NO_x, and CO_2 from certain highly polluting electricity generators in a cap and trade program. The program is a targeted annual program in addition to the state's implementation of a seasonal NO_x cap and trade system and in addition to the US EPA's implementation of an annual SO_2 cap and trade system.

Geographic Scope – New Hampshire

Enabling Authority – Specific statutory authority. Statute RSA 125-O

Program Duration – Compliance plan must be submitted by July 1, 2003. Emissions budgets take effect December 31, 2006. Budgets are annual rather than seasonal.

Program Goal – Lower emissions of harmful pollutants from largest, oldest, and least efficient power plants in order to further protect public health and the environment and to address local air quality concerns.[50] The purpose of the statute is to control emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2) from affected facilities in New Hampshire. The department will recommend a mercury budget following study and analysis. Output based allocations reward efficient electricity generation. The program provides an incentive to purchase allowances within the OTR since it requires the purchase of 0.8 allowances for each ton of emissions if the allowances are purchased from sources inside the OTR.[51]

Program Implementation

Implementing Agency – New Hampshire Department of Environmental Services (NH DES).

Organization Providing Service – Affected generators in New Hampshire must comply with this statute. An affected facility is defined as an existing fossil fuel burning steam electric power plant unit, specifically Merrimack Units 1 and 2 in Bow; Schiller Units 4, 5, and 6 in Portsmouth; and Newington Unit 1 in Newington, excluding any of these units that may be repowered.

Administrative Complexity – Low. This statute includes multiple features that could affect administrative complexity: it is multi-pollutant, it is output based, and it focuses on a subset of generation sources in the state. We discuss each of these features separately. However, overall the administrative complexity of these statutes is low. The multi-pollutant aspect introduces significant administrative efficiency for both the affected facilities and the implementing agency. The multi-pollutant approach enables the

[50] Background Document and Technical Support is the *"New Hampshire Clean Power Strategy"*, January 2001 available at http://www.des.state.nh.us/ard/nhcps.htm

[51] Personal communication with Andy Bodnarik, NH DES, January 11, 2002.

consolidation of compliance planning, measurement, reporting, and verification activities both for the affected facilities and the agency. This approach also relies on the same output data for all pollutants. The statute's use of an output-based allocation does not significantly increase the administrative complexity. An output-based allocation requires only net generation data in addition to the emission data that is already routinely reported to the US EPA. Net generation data is widely available publicly, and is metered for financial settlement reasons within an electrical control region.

If requirements pertaining to mercury are added, there could be additional work at a later date. For example, the agency would have to determine how to measure and monitor mercury emissions (e.g. using mercury content of fuel, or monitoring stack emissions,) new measurement verification methods, and would have to develop data substitution and stack testing protocols. Although there are currently no requirements for monitoring, measuring or controlling mercury, it appears likely that mercury will become a regulated pollutant and the agencies efforts on this front would not be wasted.[52] The target facilities are higher emitting facilities, and are all required to file with EPA. As such the facilities are all within the scope of existing requirements. The requirements in this statute represent a requirement in addition to regulatory requirements under existing cap and trade programs, thus they require that affected facilities submit, and the implementing agency review, one additional compliance plan. Thus it would add some additional staff hours for the affected facility and the agency. However, because the statute relies primarily on data that is compiled for other regulatory purposes, the additional staffing requirements are likely to be small. Any violations of the statute would be in addition to violations of other requirements, so they may require additional enforcement actions that would require agency activity.

Feasibility – Medium to high. At the time this statute was introduced it was very controversial with strong proponents and strong opponents. Citizens concerned about local air quality impacts were strong proponents of the stringent new caps, but they opposed the inclusion of trading provisions in this statute. In the past few years there has been a state and national trend toward control of emissions on a multi-pollutant basis, and on an output basis, to capture efficiencies and to assist generation owners with their compliance activities so that they can assess control requirements and options comprehensively. Consequently, owners of the affected facilities were strong proponents of the multi-pollutant cap-and-trade concept, but they opposed the stringency of some of the caps. The statute seeks to balances concerns over local air quality and concerns over cost of compliance. Regulatory programs such as this are likely to become more and more feasible, especially on a regional and/or national basis.

Input to Program Development – The origins of this statute are in a public petition presented to the Governor of New Hampshire. Many environmental and public health groups submitted a petition for government action in late 2000. The petition sought emission reductions from the state's oldest and dirtiest coal and oil-fired generation facilities. Governor Shaheen pledged to get the power plants to achieve additional emissions reductions. The New Hampshire DES conducted a series of meetings between

[52] See, e.g. STAPPA ALAPCO comparison table of Federal Legislation in Appendix B.

petitioners, electric companies, and other interested parties. Subsequently, the Department issued its *"Clean Power Strategy"*, which formed the basis for the *"Clean Power Act"*, and received written comments as well as oral testimony.

Program Assessment

Costs and Benefits – Output-based allocations encourage generation efficiency. Multi-pollutant statutes can reduce the total costs of compliance with statutes because of the opportunity for integrated decision making on compliance options. NH DES anticipates that emission reductions from the electric generating industry, and the affected facilities of this statute, will reduce air pollution, benefit the environment and be cost-effective. The statute establishes a regulatory program for implementing a comprehensive and integrated emission reduction approach for New Hampshire' electric generating plants, which are among the largest emitting sources. Emission control strategies implemented for compliance will allow for more efficient combustion units and air pollution controls that reduce multi-pollutant emissions in a manner that is technically and economically feasible.

DES estimates that control costs with budget allocation and trading, as follows, would be significantly lower than implementation of environmental performance standards. In November 2001, SO_2 and NOx allowances were available for approximately $165 and $500 per ton, respectively. Assuming 1999 generation levels, SO_2 compliance achieved exclusively by trading would require 22,277 allowances costing about $3,675,705 per year. Similarly, NOx compliance achieved exclusively by trading would require 8,433 allowances costing about $4,216,500 per year. The worst-case estimate for SO_2, NOx, and CO_2 compliance would thus total about $7,937,912–$8,196,921 per year. The Department will re-evaluate the cost of mercury controls when it proposes a mercury budget to be included as part of this statute in 2004. NH DES believes that multi-pollutant control strategies that can be implemented for compliance with this statute can result in reduced annualized costs for capital and operating and maintenance compared with single pollutant regulatory programs. By inclusion of trading which lowers costs, lower emissions caps are feasible, resulting in greater environmental benefit.

Emission Reduction Potential by Pollutant – High. The statute establishes annual caps on emissions from certain generation sources.

Sulfur dioxide: Annual cap based on 3 lbs/MWh. Through trading, the Department expects to achieve a reduction in the aggregate average SO_2 emissions from all of the affected units of 75% below Phase II of Title IV of the Clean Air Act, reducing total SO_2 emissions by 89% since 1990.

Nitrogen oxides: Annual cap based on 1.5 lbs/MWh. The Department expects to achieve a 70% further reduction in annual NO_x emissions, above and beyond the 68% annual (76% seasonal) NO_x reduction that New Hampshire has already achieved, reducing total New Hampshire NO_x emissions from these sources by 90% since 1990.

Carbon dioxide: Annual cap at 1990 levels. The Department expects to achieve a 3% reduction below 1999 CO_2 emission levels, reducing annual CO_2 emissions from these sources to 1990 levels, consistent with the Climate Change Action Plan adopted by the New England Governors and Eastern Canadian Premiers.

Program Evaluation – The program has not yet been evaluated.

Key Issues

Strong support from certain generation sources and from citizens contributed to success of this effort. Pressure from citizens groups created a strong political climate for the State of New Hampshire to take action to reduce emissions from the state's oldest and dirtiest facilities. Support from all affected generation sources facilitated the development of this policy.

Another key issue is the consistency of this policy with developments in the electricity industry and with the state's economic policy of enhanced and efficient competition in the electricity industry. Each aspect of this policy is consistent with the state's restructuring efforts and increased emphasis on ensuring efficient competition in the industry.

Sources of Information

The statute is available at the following website:

http://www.gencourt.state.nh.us/ie/billstatus/billstatuspwr.asp

and the technical support document is available at:

http://www.des.state.nh.us/ard/nhcps.htm

STAPPA/ALAPCO Multi-Pollutant Strategy Components – Comparison of Approaches November 29, 2001, contained in Appendix B of this report.

3.4 NO_x Budget Allocation

Program Description

Program Vehicle – Some states allocate the allowances available under the NO_x Budget Program in a fashion that rewards efficient generation, energy efficiency, and innovative emissions reduction programs. These allocation methods include allocating first to new sources based on permitted emission levels (CT), allocating based on electrical output (MA), and providing a set-aside for efficiency and/or renewables (MA, NH, NJ), or generation efficiency (NY).

Geographic Scope – Connecticut, Massachusetts, New Hampshire, New Jersey and New York.

Enabling Authority – State regulation.

Program Duration – Years following 1999

Program Goal –Reduce emissions from power plants and large stationary sources, encourage pollution prevention and the operation of cleaner more efficient energy sources. Different states are taking different approaches. For example, Massachusetts has allocated allowance to generation sources on an output basis. Massachusetts also has a 5% set-aside for new units, and a 5% Public Benefit set-aside to be allocated to energy efficiency and renewables. New Hampshire will be moving to output based allocation following 2006. The state has a 10% set aside in 2002, increasing to 14% in 2003 for new units, energy efficiency and renewables and it retires 100 allowances for environmental benefit. New Jersey has a set-aside for new generation sources and a set-aside for energy efficiency and renewables; the total for both set asides is 9%. The state also allocates allowances from its incentive reserve on an output basis. New York uses excess allowances from it new source and efficiency and renewable set-asides to reward generation efficiency.

Program Implementation

Implementing Agencies – State Department of Environmental Protection

Organization Providing Service – Allowance allocation regulations apply to "Budget Sources." A "Budget Source" means a fossil fuel fired boiler or indirect heat exchanger with a maximum rated heat input capacity of 250 MMBtu/Hour or more; and all electric generating devices with a rated output of 15 MW or more. States also allow other sources to opt in to the allowance allocation.

Administrative Complexity – Low. The allowance program is administered by the federal EPA Clean Air Markets Division, and States have minimal administrative duties. For the output based allocation in Massachusetts it is necessary to add data on electrical output. This data is widely available and needed for other purposes than the output-based allocation. There is no other difference otherwise between an output-based and input-based allocation.

Some additional administrative issues can be introduced in the way in which a state chooses to set-aside new generation allowances or to provide incentives for demand side reduction, renewable, or generation efficiency. However, these set-asides are consistent with EPA recommendations for allowance allocation. An individual state has to get involved in approving programs that earn allowances from the set-aside accounts and the details of how programs, such as individual energy efficiency programs, can earn allowances are still being worked out.

Feasibility – High. Allowance allocation programs already exist. Lowering the budgets to increase the reductions and the environmental benefits may be less feasible, based on contentious litigation of the EPA's NOx SIP Call Program and the difficulty that some States and the federal government have experienced in attempts to pass new legislation.

As discussed above, output based approaches to emissions regulation are increasingly common and receive strong support from the newer, more efficient generation sources.[53] Commenters to the Massachusetts Department of Environmental Protection stated that the proposed allocation was practical to implement, flexible, suitable for application to a variety of plant configurations and permits management of efficiency parameters.

Input to Program Development – Typically, States receive input from stakeholders on allowance allocations. The OTC already received input on the basic design of the program during the development of the OTC Model Rule, and other elements of the program should be fairly consistent from State to State. EPA has issued additional guidance on the development of budget programs, as well.

For its output-based allowance allocation, Massachusetts DEP convened a series of meetings that included Budget Sources, other agencies, and other interested parties. These meetings preceded the agency's proposed regulations and public comment period.

Program Assessment

Costs and Benefits – Output-based allowance allocation, with its emphasis on generation efficiency, encourages pollution prevention and the operation of cleaner and more efficient energy sources. This allocation also is consistent with the move in the electricity industry toward competitive wholesale markets and contributes to the establishment of a fair competitive generation market by removing the grandfathering of older and dirtier generation sources. Set asides for renewables and energy efficiency create a gradual trend to reducing emissions from generation sources included in the allowance allocation.

Emission Reduction Potential by Pollutant – Allowance allocation that rewards generation efficiency, such as output-based allocation of NOx allowances, and that incorporates energy efficiency and renewables provides significant collateral reductions in other pollutants. Regulation does contain some provision for periodic evaluation of regulation 7.28

Program Evaluation – Most state regulations contain a provision for periodic review of the regulation. A recent report evaluates cap and trade programs.[54] One could evaluate the relative cost impact of allowance allocation (such as an output based allocation) on different fuel sources and different affected sources in order to consider what impact the allocation would have on overall electricity system dispatch. See also, http://www.epa.gov/airmarkt/otc/index.html for information on OTC's NO_x Budget Program.

[53] See discussion above under Multi-pollutant Output Based Emissions Standards for High Emission Sources

[54] "How Environmental Laws Work: An Analysis of the Utility Sector's Response to Regulation of Nitrogen Oxides and Sulfur Dioxide Under the Clean Air Act," Byron Swift, Environmental Law Institute, Published at 14 Tulane Environmental Law Journal 309 (Summer 2001)

Key Issues

The mass-based NO_x Budget Program applies to new sources, as well as existing sources, thus it may provide more long-term environmental benefit than rate-based emission performance standards. This is because rate-based emission performance standards allow gradual growth in overall emissions as more and more new units come online, offsetting the fact that these new units emit at much lower rates than existing units. This is one reason why the OTC favored a cap-and-trade program for the second and third phases of NO_x RACT, which originally was a performance standard.

Secondly, the trading element of cap-and-trade programs lowers implementation costs, which improves the feasibility of the adoption of more stringent regional or national reductions.

Output-based allocation encourages generation efficiency and is consistent with competitive electricity markets. The general trend towards out-put based standards and allocations, coupled with the strong support for out-put based approaches among many electrical generators makes the adoption of out-put based approaches highly feasible.

Designing set-aside programs for energy efficiency and renewables will increase emission reductions achievable under a cap and trade system. However, numerous details remain to be worked out regarding how non-traditional resources can be incorporated into the allowance program.

Sources of Information

Connecticut's post 2002 NO_x budget program is contained in regulation 22a-174-22b (October 1999).

Massachusetts' NO_x budget program is contained in 310 CMR 7.28, and is available at http://www.state.ma.us/dep/bwp/daqc/files/728reg.pdf

New Hampshire's NO_x budget program is contained in Env-A 3200, available at http://www.des.state.nh.us/ard/enva3200.htm

New Jersey's NO_x budget program is contained in subchapter 31 at www.state.nj.us/dep/aqm/rules.htm

3.5 Distributed Generation Programs

Program Description

Program Vehicle – Emission standards, emission-based fees, and/or an emission certification program for distributed generation (DG). There term "DG" refers to small electric generating units, under roughly one MW in size, sited close to the point of use. These units are often owned and operated by electric consumers rather than by utilities or large energy companies.

Geographic Scope – Three states – Texas, New Hampshire, and California – currently have rules in place that address emissions from DG. Air regulators in Connecticut and

New York are also developing rules or streamlined permitting processes focused on DG emissions.

Enabling Authority – The establishment of emission standards, emission-based fees, or a certification process falls within the traditional authority of state air regulators.

Program Duration – As an addition to existing state emission rules, emission standards or emission-based fees for DG will remain in effect until modified. States are generally not considering sunset clauses to these rules.

Program Goal – Regulators are turning to emission standards or emission-based fees for DG with two goals in mind. One goal is to prevent high-emitting generators, such as diesel-fueled units, from being operated for economic reasons (i.e., in a baseload or peak shaving mode). In the past, these units have been used primarily as emergency generators, however as the electric industry evolves, many customers are considering using them for economic purposes. In some states, applicability thresholds allow units of considerable size to be installed without going through the permitting process with which larger plants comply. The second goal (and the primary goal of certification programs) is to streamline the process of permitting small generators by establishing a technology certification process. Clean DG can be supported by establishing a certification process for units that meet particularly stringent emission standards.[55]

Program Implementation

Implementing Agencies – State environmental agency

Organization Providing Service – Residential, commercial and industrial electricity consumers installing small generating units comply with DG emission standards or pay emission-based fees in New Hampshire. DG is distinct from traditional power plants in that it is often owned and operated by end users, not by large energy companies.

Administrative Complexity – Low. Emission standards for DG are established in a traditional rulemaking process with which air regulators are familiar. While there is a considerable amount of data to review in determining the appropriate level of the standard, once it is established, the standard can remain in place for a significant period with minimal review to determine whether it needs to be revisited. Further, future rulemakings will benefit greatly from the work done in the first several rulemakings (Texas, New Hampshire, California and the RAP Model Rule). This will make future rulemakings less labor intensive for both regulators and interested parties.

[55] Note that the model DG Emissions recently released by the Regulatory Assistance Project cites as the goals of the rule: "to regulate the emissions of certain pollutants from smaller-scale electric generating units… and reduce the regulatory and administrative requirements for siting units that are affected by this rule." See: *Model Regulations for the Output of Specified Air Emissions from Smaller Scale Electric Generating Resources*, Public Review Draft, November 2001, the Regulatory Assistance Project, at www.rapmaine.org.

An important benefit of the technology certification is that it reduces the administrative burden on both air regulators and the regulated sector, as the demonstration of technology compliance is done once for each technology, and not once for each installation.

Feasibility – The establishment of emission standards and certification for DG is highly feasible. Because industries in the U.S. are familiar with emission standards and certification processes, there is not likely to be controversy over whether the standards will be effective or whether air regulators have the authority to establish them. The controversy will be over the level of the standards. This controversy can be quite heated, because in many states the process will signal an end to a permitting exemption enjoyed by some sizes and types of electric generators. The more stringent the standards proposed, the more heated the controversy is likely to be. (See the discussion of "Key Issues" below.)

Input to Program Development – The rulemaking processes in Texas, New Hampshire and California included stakeholders such as DG technology manufacturers, environmental groups and regulators. Although meetings and technical sessions were publicized, there was almost no input from the public.

Program Assessment

Costs and Benefits – None of the states adopting DG emission standards or certification programs have calculated the expected costs or benefits of the rule. This is not surprising, as the task would entail a number of complex assumptions about technology adoption under different regulatory scenarios, market prices and DG operation patterns.

In the case of DG emission standards, both costs and benefits depend on where the standard is set and the extent to which market prices drive adoption and operation of DG. More stringent standards will impose greater costs on consumers, as they will have to buy cleaner – and thus more expensive – generators.[56] These cleaner generators will provide the benefit of reduced air emissions. The first difficulty here is in establishing cost and emissions baselines – how much DG and what kind of DG is installed in a "business as usual" scenario?

The second difficulty comes in predicting market prices and how owners of DG will operate the units in response to those prices. Where prices are more volatile (or persistently high, as in a region short on supply), one would expect DG to be operated more hours per year than in other regions. (One would also expect more DG units to be installed amid volatile prices than elsewhere.) Thus, even where the fleet of DG is known with some certainty, the operation of that fleet is a rather complicated modeling question.

One effort has been made to model emission reductions from DG standards. The Natural Resources Defense Council (NRDC) developed a model to address this question and has

[56] While it is not true for all power plants that cleaner is more expensive, this rule holds true for the market-ready DG technologies. Diesel- and natural gas-fired internal combustion engines are the lowest-cost and highest-emitting units available. Microturbines are more expensive but cleaner, and fuel cells and renewable resources are the most expensive and cleanest.

done several preliminary model runs. NRDC released draft results early in 2001. (See discussion below, under "Emission Reduction Potential by Pollutant.")

One clear issue regarding DG standards is that *certification programs reduce administrative costs for both regulators and applicants.* A fairly accurate assessment of the savings (benefits) from certification programs could be made by calculating the average costs of a single permitting process to both regulators and the applicant. One could then simply apply this cost figure to the various projections of new DG installations in a given region to generate a range of total savings. Again, a difficulty here would come in factoring in the impact of the certification program itself on DG market penetration, as lower administrative costs would increase installation numbers somewhat. This would have to be done with an informed assumption about the sensitivity of the technology adoption decision to administrative costs.

Emission Reduction Potential by Pollutant – As noted, only one study, by NRDC, has attempted to quantify emission reductions from DG standards. Using their Distributed Resources Emissions Model (DREM), NRDC modeled electric industry emissions under three scenarios. The first scenario (called "business as usual") assumes no policy intervention and calculates DG market penetration and emissions based on the costs of each technology.[57] The second two scenarios assume progressive implementation of two DG emissions standards nationally between 2001 and 2006. One scenario is based on a single standard, and the other, on a three-tiered standard. The level of these standards is loosely based on the standards adopted in Texas and under consideration in California and the Northeast.

These figures represent nationwide emission reductions in the year 2015. For each DG emission standard scenario modeled, reductions are calculated from the "business as usual" scenario. The range of reductions shown reflects different assumptions about electricity prices and what generating units are displaced by DG.

Table 4: NRDC Draft Results from DG Standard Modeling

Standards	NO_x (kTons)	SO_2 (kTons)	CO_2 (MTons)	PM (kTons)
Single Standard	78-313	18-181	7-29	2-8
Three-Tiered	78-297	18-155	7-23	2-8

Program Evaluation – No DG emission standards have been evaluated yet.

Key Issues

As noted, most of the controversy in establishing DG emission standards is likely to revolve around the level of the standard. Some state regulators (such as those in California) are focused on establishing standards consistent with those facing a new combined-cycle gas turbine (CCCT) with Selective Catalytic Reduction (SCR) controls.

[57] The DREM model uses the market penetration function from the Department of Energy's National Energy Modeling System (NEMS).

These plants are currently being permitted with NOx limits in the range of 0.10 lb/MWh to 0.05 lb/MWh across the U.S. It is unlikely that the reciprocating engine technologies (diesel and natural gas fueled) could achieve NOx rates at the low end of this range in the foreseeable future. Microturbines may be able to achieve such NOx rates with additional emission reductions and aggressive use of byproduct heat. All fuel cell technologies currently have NOx rates well below the range of new CCCTs.

The NOx standards adopted in Texas and proposed in California and by RAP are shown in the table below.

Table 5. Selected NOx Standards for DG (lb/MWh)

NOx Standard	Current	2003	2005	2006	2009
Texas rule	0.47	no change	0.14	no change	no change
California draft rule	none	0.5	0.07	no change	no change
RAP model rule	none	0.5-0.47	no change	0.3-0.27	0.15-0.07

Sources of Information

At www.rapmaine.org, see: *Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generating Resources*.

At http://www.arb.ca.gov/regact/dg01/dg01.htm, see: *Proposed Regulation Order: Establish a Distributed Generation Certification Program* and related documents.

See: Lents and Allison, *Can We Have Our Cake and Eat It Too? Creating Distributed Generation Technology to Improve Air Quality.* Prepared for the Energy Foundation, December 2000, Grant No. G-0001-05083.

New Hampshire's NOx Emissions Reductions Fund program is contained in Env-A 3700, available at http://www.des.state.nh.us/ard/prpsdrul.htm.

3.6 Information Disclosure

Program Description

Program Vehicle – Electricity suppliers are required to provide information on fuel type and emissions to electricity consumers to facilitate informed customer choice of electricity supplier. The environmental information must be provided in a standardized format and distributed to customers through such mechanisms as bill inserts, advertising materials, and customer contracts.

Geographic Scope – Existing disclosure policies are state mechanisms, applicable statewide. States with disclosure requirements include the following states in the OTC region: CT, ME, MD, MA, NJ, NY, and RI.[58] NH is waiting for the NHPUC to issue rules.

[58] Other states with disclosure policies include CA, IL, NV, NM, OH, OR, and TX.

Enabling Authority – Sate legislature.

Program Duration – On-going. Disclosure requirements take effect in 1999 and later years.

Program Goal – Provide electricity consumers with information in a consistent format that will permit them to take into account factors, including the environmental attributes of electricity supply, in selecting an electricity supplier.

Program Implementation

Implementing Agencies – Generally the public utilities commission develops regulations to implement the statutory requirement for information disclosure. In a number of states, the public utilities commission consulted extensively with other state agencies such as the environmental protection agency, in developing the regulations.

Organization Providing Service – Electricity suppliers are required to provide information disclosure labels to prospective and current customers.

Administrative Complexity – Low. Providing an information disclosure label to customers is not complex. Once a company has developed its information disclosure label, it is a relatively simple matter to update the label as required on a quarterly or longer basis. There is significant administrative complexity with establishing a reliable and accurate source of data for the information disclosure labels (See GIS discussion under Key Issues).

Feasibility – High. The early years of establishing information disclosure requirements and regulations revealed significant opposition to mandatory disclosure for all electric suppliers. However, information disclosure is now a widely accepted component of electricity restructuring efforts, and there are now a sufficient number of states with information disclosure requirements that states seeking to establish similar requirements should not encounter significant opposition and can benefit from lessons learned in other states. While disclosure emerged as a policy related to electric industry restructuring, electric industry restructuring is not a prerequisite for information disclosure. Perhaps the most daunting feasibility issue relates to the development of a reliable and accurate source of data (see GIS discussion under Key Issues).

Input to Program – Different states have followed different processes in developing information disclosure regulations. In New England, there was an extensive regional coordination effort among public utility commissions and other stakeholders in developing information disclosure regulations. In particular, stakeholders in the region participated in a professionally facilitated multi-month process for developing model disclosure regulations. The collaborative process included environmental and utility regulators, electric utilities, electricity suppliers, generators, public interest groups and other stakeholders. The Regulatory Assistance Project (RAP) provided technical assistance in developing proposed model regulations (See RAP report listed in Information Sources, below). Subsequently, staff from the six utility commissions in the region issued model regulations designed to serve as the basis for information disclosure proceedings in each of the six New England states.

Following issuance of the model regulations, individual states undertook regulatory proceedings in compliance with individual state requirements for regulatory proceedings. Each state followed its required practices for regulatory proceedings in circulating proposals, and accepting and responding to comments from the public and stakeholders.

Program Assessment

Costs and Benefits – (budget levels, sources and types of funding, environmental and public health benefits). There is increasing evidence that many electricity consumers would like to support low emission electricity resources. Information disclosure is one method for enabling consumers to exert some market pressure for the use of low emission resources. While compliance with information disclosure requirements entails some cost, there is no indication to date that the costs are large on a per kilowatthour basis.

Emission Reduction Potential by Pollutant – (annual and program lifetime). Low. The impact of information disclosure policies on the overall environmental footprint of the electric industry is likely to be low. The effectiveness of these policies in reducing air emissions from the industry and creating demand for new low emissions resources will depend on factors such as the total demand for low-emission electricity sources relative to the availability of existing low emission resources, the interaction of this policy with other policies such as renewable portfolio standards, and the interaction of this policy with electricity suppliers' marketing efforts.

While information disclosure provides a basis for comparison of different suppliers' offerings, the policy is unlikely to have much of an incremental impact on the environmental footprint of the industry beyond what would occur to comply with renewable portfolio standards, and through marketing products to consumers who are interested in purchasing "green power".

Program Evaluation – (available results and assessments). A recent study by the National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratories concludes that customer-driven markets for renewable energy are unlikely to remove the need for specific policies to increase the penetration of renewable energy resources in the electricity mix. The report states that market simulations suggest that 10-20 percent of customers will choose "green power" when given an opportunity to do so; however, actual market data shows that only about one percent of customers actually have chosen "green power" given the opportunity.

Key Issues

There are multiple key issues in the development of information disclosure regulations. These issues include:

- Application of requirements to standard offer supply as well as competitive supply.
- Finding a source of accurate data that avoids double counting and is reliable.
- Treatment of imports from other regions.

Perhaps the most important issue pertains to the source of data upon which the information disclosure will be based. In order for information disclosure to be meaningful, there must be a single data source that is accurate and verifiable. This issue has been particularly complex in New England since the New England control region comprises six states. The Generation Information System (GIS) under development at NEPOOL would provide the informational basis for a New England wide source of data for compliance with information disclosure requirements in New England states. The GIS being contemplated would "tag" all kWhs generated, and enable resource attributes to be sold separately from kWhs of electricity.

This GIS has been under development for several years in New England. The effort began several years when public utility regulators approached ISO New England about creating an information system that would underlie a variety of state policies including disclosure, RPS, and emissions performance standards. Subsequently a small working group was created that included representatives of utility commissions, environmental regulatory agencies, ISO New England, and NEPOOL Participants. That group met regularly over nearly a year to identify the information needs for compliance with state policies, what information would be available through ISO New England's market settlement system, and to reach agreement on the components of a GIS.

One of the most contentious issues was whether to use a "tracking system" where attributes of generation from a specific generating unit would be sold with kilowatthours of generation from that generating unit. The alternative was to use a "tagging system" where the attributes of generation could be sold separately from the kilowatthours of generation. Despite the strong commitment of both economic regulators and environmental regulators to the use of a tracking system, the current GIS for New England is based on a tagging approach. This concession on the part of state regulators was driven primarily by the necessity of moving beyond the stalemate between regulators and NEPOOL Participants on this issue. Recently, ISO New England identified the GIS as a best practice in comments to FERC pertaining to Northeast Regional Transmission Organization.

To date ensuring a consistent and reliable source of data to comply with disclosure requirements in New York has not presented to coordination issues that New England has faced because the state is itself a control region. The New Jersey Department of Environmental Protection has been a strong proponent of a tracking based information system for implementation in New Jersey and other states in the PJM control region. The development of a GIS in PJM is just beginning, with a GIS Users Group Meeting scheduled during November, 2001 in PJM. Coordination issues will become increasingly prominent given FERC's push for a three-region Regional Transmission Organization.

There are a number of related efforts to assist consumers in making decisions about electricity supply. For example, the Green-e program of the Center for Resource Solutions certifies renewable electricity products that meet the environmental and consumer protection standards established by the Program. The Program also requires that electricity providers disclose information about their product to their customers in a standardized format. These efforts are intended to identify certain resources that meet a defined standard of environmental quality. The Sustainable Energy Development

Authority in Australia requires that 60% of green power sold must be from new resources by the end of 1999 in order to use their state-sanctioned logo.

Sources of Information

Individual state public utility commission websites.

New Jersey: www.bpu.state.nj.us

Maine: www.state.me.us/mpuc/

Massachusetts: http://www.state.ma.us/dpu/index.htm

http://www.rapmaine.org/disclose.html. Reports at this website include: Information Disclosure and Labeling for Electricity Sales: Summary for State Legislatures. (From RAP's Consumer Information Disclosure Series, National Council on Competition and the Electric Industry, April 1999).

Forecasting the Growth of Green Power Markets in the US. Ryan Wiser, Mark Bolinger, Ed Holt, Blair Swezey, Lawrence Berkeley National Laboratory, National Renewable Energy Laboratory, October 2001. Available at: http://www.eren.doe.gov/greenpower/pdf/30101.pdf

American Solar Energy Society: Information Disclosure position paper available at http://www.ases.org/solarguide/disclosure.html

Green-e program: http://www.green-e.org

EPA's Emissions and Generation Resource Integrated Database is a useful source of data to integrate into information disclosure requirements and compliance: http://www.epa.gov/airmarkets/egrid/index.html

III. Calculating Comparative Emission Reduction Potentials

The OTC requested, as part of this project, that Synapse compare the potential emissions reductions from a variety of policies and programs affecting the electric industry. For this survey, we provide a comparison of potential annual emissions reductions from implementation of specific policies. To provide a common point of comparison for each program reviewed, we estimate potential emission reductions associated with implementation of that program throughout all the states in the Ozone Transport Region in the year 2005. Our estimated emissions reductions represent the difference between our estimates of potential emissions in 2005 with and without implementation of the policy. Without such assumptions to normalize the estimates, comparison of different programs becomes less informative, as differences in potential emission reductions could be due to one or several factors such as program details or funding level, area of implementation, and time period of implementation.

In this section, we explain our methods and assumptions for developing estimates that illustrate the magnitude of potential emission reductions associated with the implementation of selected policies described in this report. These estimates provide one of several tools to use in identifying policies that are promising for their potential environmental benefits and are worthy of further study. However, these estimates are intended only for comparative purposes; they are not based on detailed modeling of these policies or regional plant dispatch. This section first explains our general method for estimating emission reductions from programs. The general explanation is followed by a more specific discussion pertaining to each program assessed. Finally we provide some general observations on potential emission reductions from policies.

One of the main challenges in developing these estimates is identifying simplifying assumptions that permit meaningful comparison across what in some instances are very different programs. For example, some of the policies and programs affect the quantity of electricity consumed (energy efficiency), some of the policies and programs seek to address generation resource mix (renewable portfolio standards, and state purchasing requirements), some of the programs are targeted directly to reducing emissions from specific or all generation resources (e.g. output based standards for certain generating plants, or allocation of emission allowances). Further, some of the policies address wholesale generation, while others affect retail consumption. Comparison is further complicated by the fact that emission characteristics of the electric system vary geographically both within an electrical control region and between electrical control regions. Emission characteristics also vary from season to season.

The results of our emission reduction potential calculations are shown in Table 6, below.

Table 6. Ranges of Potential 2005 Emission Reductions from Policies Reviewed (tons)[a]

Policy	SO_2 (tons)		NOx (tons)		CO_2 (tons)	
	Low	High	Low	High	Low	High
Energy Efficiency	70	56,700	700	23,700	5,760,000	12,100,000
Load Response	(141)	843	(1412)	(2402)	(39,000)	86,300
Renewable Portfolio Standard	64	23,700	(400)	7,700	3,870,000	6,740,000
Purchasing Requirements	22	14,700	190	6,120	1,350,000	3,130,000
Emission Performance Standard	(42,000)	607,000	70,000	270,000	(31,300,000)	(4,530,000)
Output-Based Standards for High-Emitting Sources[b]	901,000[f]	1,308,000[f]	215,000	310,000	17,500,000	26,300,000
Cap & Trade Program with Output based Allocation[c]	900,000[f]	1,304,000[f]	228,000	328,000	40,000,000[g]	
Title IV, Phase II SO_2 & OTR NOx 5-month budget program		681,000		143,000[d]		No reductions
Waxman/Jeffords Bill[e]		1,690,000		478,000		40,300,000

[a] Figures in parentheses indicate potential increases in emissions. Emission reductions are not calculated for some programs discussed in this report. See Section III-2, below for a discussion of emission reduction calculations for all programs.

[b] These figures represent an extrapolation of the Massachusetts rule at 310 CMR 7.29 program to the entire OTR. Reduction requirements are detailed in Section III-2 below. We assume all plants 100 MW and greater are affected; limited trading is allowed for NO_x compliance; and offsite reductions are allowed for CO_2 compliance.

[c] These figures represent extrapolation of a program similar to New Hampshire bill RSA 125-O to the entire OTR. Reduction requirements are detailed in Section III-2 below. We assume all fossil-fired steam units 25 MW and greater are affected, and sources can comply with NO_x and SO_2 limits by purchasing NOx Budget and Acid Rain allowances.

[d] This figure applies only to the summer ozone season; it represents the reductions achieved by the declining cap on summer emissions between 1998 and 2003.

[e] These figures represent the OTR reductions that would be achieved by enactment of a Federal multi-pollutant bill similar to the Waxman/Jeffords bill (HR 1256/S556). Reduction requirements of this bill are discussed in the paragraph below. Note that while this bill applies only to power plants older than 30 years, the calculations here apply the percentage reductions to all fossil-fired steam plants in the OTR.

[f] Average emission rates for sources affected by these policies are contained in Tables 11 and 12. Average emission rates are lower for sources greater than 25 MW than they are for sources greater than 100 MW.

[g] The NH DES has provided this estimate of the potential emission reductions from OTC wide implementation of a policy to reduce utility sector emissions to 1990 levels. Synapse Energy Economics has not independently verified this calculation, but we include it for illustrative purposes.

For comparison, we have included an estimate of the impact of a Federal multi-pollutant bill on the OTR. To calculate these numbers, we have assumed that a variation of the Waxman/Jeffords bill (HR 1256/S556) is enacted. Targeting power plants older than 30 years, this bill would reduce SO_2 emissions (from these plants) by 75 percent below the levels of Phase II of the Acid Rain Program. It would reduce NO_x emissions from these plants by 75 percent below 1997 levels, and reduce their CO_2 emissions to 1990 levels. All reductions would have to be achieved by 2007. The numbers in Table 6 are the reductions that would be achieved if these requirements were applied to power plants in the OTR.

The following figures represent our estimates of potential emission reduction from implementation of specific policies in graphic format.

Figure 1. Potential 2005 SO_2 Emission Reductions Due to Implementation of Policies on Stand-alone Basis

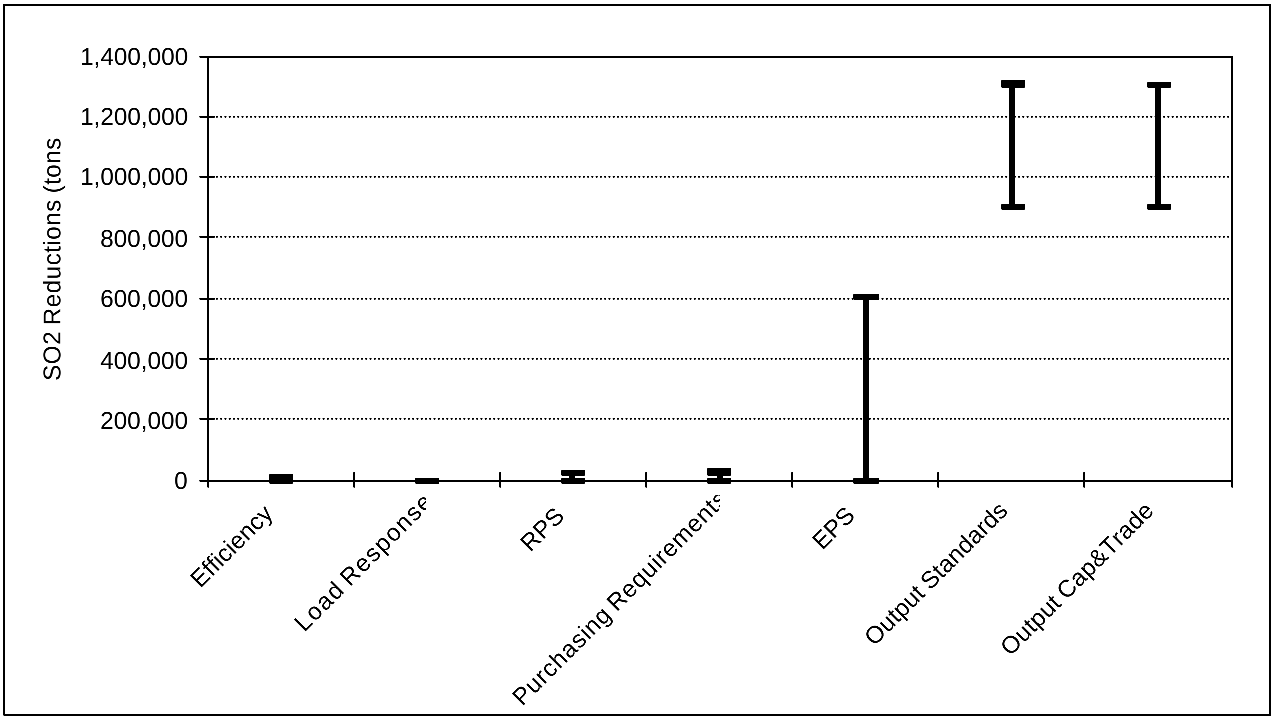


Figure 2. Potential 2005 NO_x Emission Reductions Due to Implementation of Policies on Stand-alone Basis

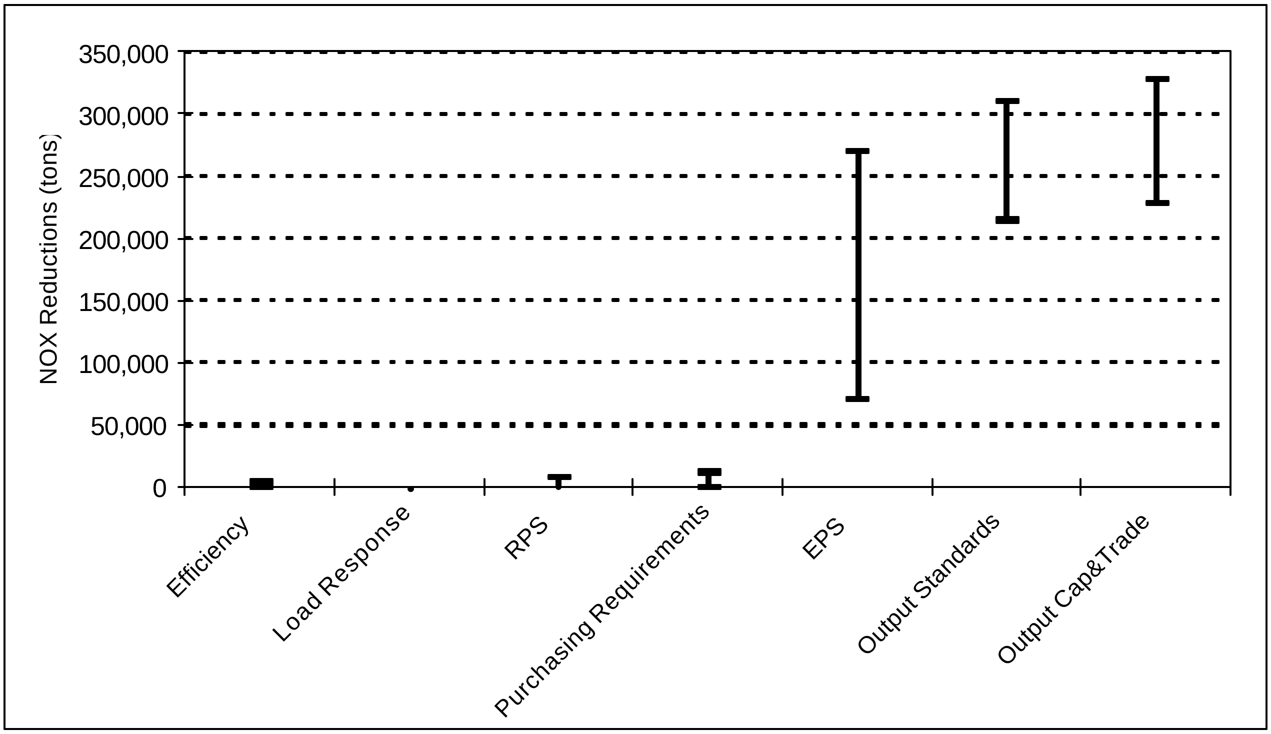
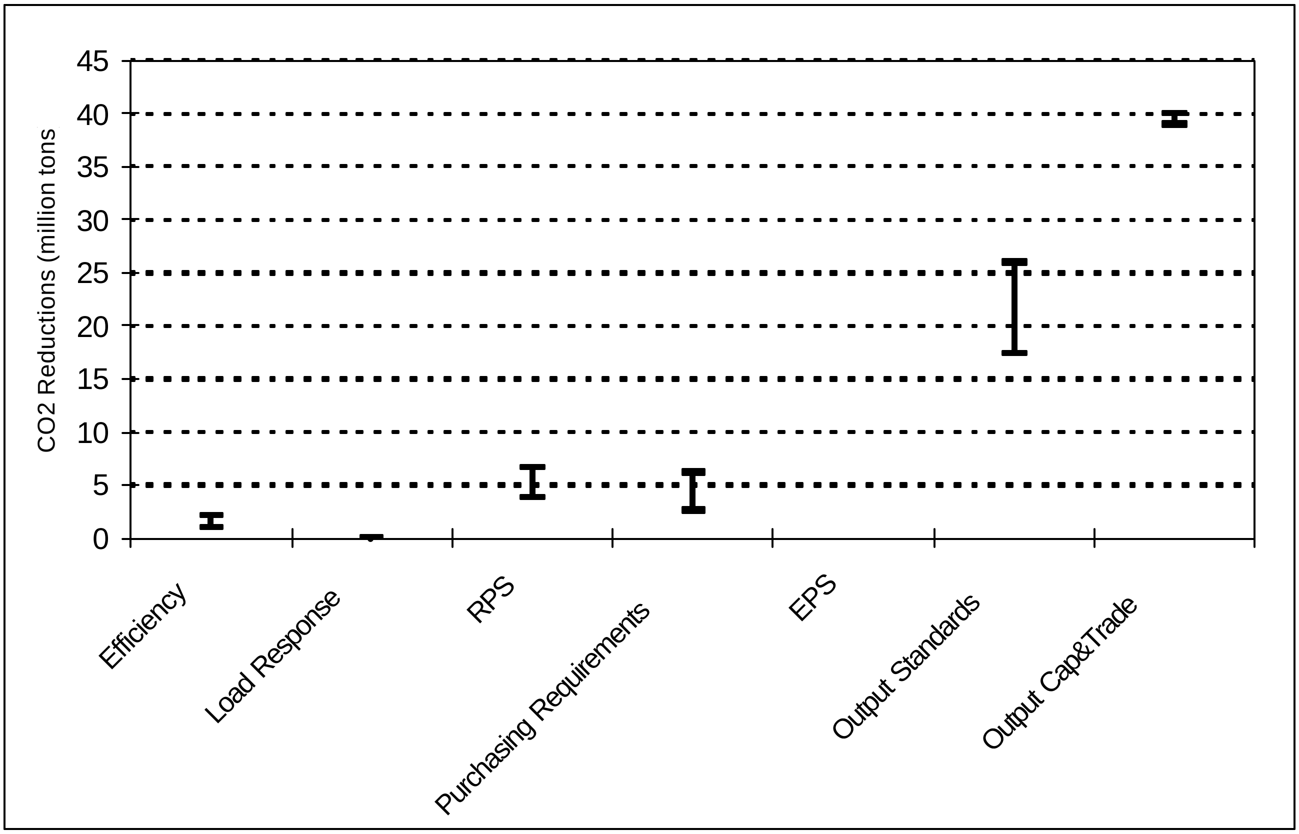


Figure 3. Potential 2005 CO_2 Emission Reductions Due to Implementation of Policies on Stand-alone Basis



Note 1: The graph does not show a potential emission reduction for the EPS program because our estimates do not show a potential CO_2 emissions reductions from the EPS at the level proposed in the program reviewed.
Note 2: The estimate of the potential CO_2 emissions reductions for the Multi-pollutant Output Based Cap and Trade program was provided by the NH DES; Synapse Energy Economics has not independently verified this estimate. We have included it for illustrative purposes.

Table 7 presents a summary of the assumptions we used in developing our estimates of potential emission reductions. More detailed descriptions of those assumptions are provided in the text below the table. It is important to note that these illustrative estimates are highly dependent on the assumptions that we have used. However, we believe we have chosen reasonable assumptions, and discuss these assumptions in our description of general method, and program-specific estimates, below.

Table 7: Assumptions Used in Developing Estimates of Potential Emission Reductions

Policy	Main Assumptions
Energy Efficiency	SBC charge: $3/MWh of retail sales Efficiency cost: $23/MWh savings Three years of program implementation (i.e., 2003-2005) Low case: avoid CCCT emissions High case: avoid system annual marginal emissions
Load Response	5% peak load reduction in 50 hours 2/3 of load response is diesel DG Load response displaces CC plant Low case: low DG emissions associated with DG emissions standards, and turnover in DG stock High case: high emissions from diesel DG
Renewable Portfolio Standard	RPS = 2% of OTR energy sales, based on Massachusetts RPS with ramp up to 2% by 2005 10% of RPS met with biomass emitting NOx at 1.75 lb/MWh Low case: avoid CC plant emissions High case: avoid system annual marginal emissions
Purchasing Requirement	10% renewable purchase requirement 50% of purchase requirement met with new renewables Sales to state agencies are 14% of retail sales in each state No high emissions biomass (Note: this assumption being reviewed) Low case: avoid CC plant emissions High case: avoid system annual marginal emissions
Emission Performance Standard	EPS from NESCAUM model rule Low case: New gas capacity operates at 70% capacity factor; 35,000 MW of new gas capacity in NEPOOL, NY, and PJM; 10% reduction in SO2 and NOx emission rates at existing plants High case: load growth met by new CC plants, no emission reductions at existing plants.
Output Based Standards for High Emission Sources	Emission standards for NOx, SO2, and CO2 from MA 310 CMR 7.29 Standards applied to all sources larger than 100 MW Annual regional emission rate for affected resources from EGRID 2000 Low case: existing plants reduce operation due to entry of new gas capacity operating at 70% capacity factor. High case: existing plants continue to operate as in 1998.

Policy	Main Assumptions
Cap & Trade Program with Output based Allocation for High Emission Sources	Emission caps for NO_x, SO_2, & CO_2 from NH RSA 125-O Caps for NO_x and SO_2applied to all sources larger than 25 MW Annual 1998 regional emissions for affected resources from EGRID 2000 Low case: existing plants reduce operation due to entry of new gas capacity operating at 70% capacity factor High case: existing plants continue to operate as in 1998 Calculation of the CO_2 emission reduction potential provided by the NH DES
Title IV, Phase II SO_2 & OTR NOx summer emission reduction estimate	Emission caps for NO_x from OTC; for SO_2 from EPA Caps applied to all sources larger than 15 MW for NO_x; 25 MW for SO_2 Seasonal 1998 regional emissions for affected resources from EGRID 2000 Emission cap based on reducing regional seasonal emissions from affected sources to 143,000 tons for NO_x; 1,351,275 tons for SO_2

1. General Method

Overview

To provide a common point of comparison for each program reviewed, we estimate potential emission reductions associated with implementation of that program throughout all the states in the Ozone Transport Region in the year 2005. The key factors in our estimate are the type of program (e.g. how it affects the electric system), the potential magnitude of the program, and the emission characteristics of the electricity generation or consumption affected by the program. The basic steps in our method are described in more detail below.

For each of the programs we first determine how the program will affect the electric system. In broad terms energy efficiency and load response programs displace traditional generation resources either on an annual basis or during peak consumption periods. Similarly, renewables policies displace traditional generation resources, replacing them with renewable sources of generation. The power system emission reduction policies reduce emissions rates from existing and new generation.

Our second step is to estimate the magnitude of the program's impact. For programs that displace traditional generation (e.g. efficiency, demand response, and renewables policies), we estimate the magnitude in annual kilowatthours of displaced electricity. For programs that reduce emission rates of traditional generation resources, we estimate the magnitude in an emission rate (lbs/MWh).

For all programs the estimates of magnitude are based on a generic program design for all states in the Ozone Transport region rather than looking at state-specific program designs. Where only one state is implementing a policy or program, the generic design reflects the actual program design in that state. Where more than one state is implementing a program, we identify the most aggressive program and assume it is implemented throughout the region (e.g. energy efficiency programs and RPS).

Finally, for each program, we prepare a high and a low estimate of potential emission reductions. For programs that displace generation, the high and low estimates represent different assumptions about the emission characteristics of the displaced generation. Our high estimate is based on annual marginal emission rates for each electrical control region in the Ozone Transport Region.[59] Our low estimate is based on emission rates for new combined cycle gas turbines and for new combustion turbines. For programs that reduce the aggregate emission rate of existing generation, the high and low estimates represent different assumptions about system average emission rates or fuel specific emission rates. The following two sections provide more detail on our high and low estimates.

High Estimate of Potential Emission Reductions

For our high estimate of policies that displace generation we hold the regional generating mix fixed. In other words, there is not time for new entities to enter the power generation market, and the electrical system must respond to demand fluctuations with existing resources. In this context, any policy that reduces electricity use or adds zero emission generation reduces operation of existing marginal generating units throughout the year.[60]

Within each electrical control region generating units are dispatched generally from lowest to highest bid.[61] The dispatch order is, in economic terms, the regional supply curve. Generating units that submit low bids (generally nuclear and hydro) are dispatched first. The units that submit the highest bids (generally simple-cycle combustion turbines) are dispatched last. If demand is reduced in a given hour, the operation of baseload and intermediate units is unaffected. The only unit affected is the marginal unit in the system – the unit dispatched to meet the last increment of demand. The output of this unit would be reduced.

Thus, to assess the high range of potential emission reductions, we assume that each kWh a given policy generates (as efficiency or zero-emission generation) displaces marginal generation throughout the year. We have calculated a current (2002) "annual marginal emission rate" for New England and PJM based on fuel-specific emission rates for each region and the percent of hours over the course of a year that a given fuel type sets the

[59] The Ozone Transport Region essentially comprises three electrical control regions, New England, New York and the PJM Interconnection. Together these control regions cover the sates in the Ozone Transport region with the exception of Northern Virginia (which falls within Virginia Electric Power Company control region) and western Pennsylvania.

[60] The marginal unit in any particular hour is the unit dispatched to meet the last increment of demand. Of the generators needed to meet customer demand, the "marginal unit" is the unit with the highest bid price.

[61] The dis patch of generation resources in New England, New York and PJM control regions is done on the basis of supply bids that generation resource owners submit to the control region system operators. Generation resources are generally dispatch from lowest to highest bid; however, dispatch order is sometimes modified to address constraints on the transmission system. For example, sometimes it is necessary to dispatch a generation resource with a higher bid before a generation resource with a lower bid in order to operate the transmission in a safe and reliable manner.

marginal clearing price in the different electrical control regions.[62] Information on the percent of hours over the course of a year that a given fuel type sets the marginal clearing price in New York is not available, so we used the New England rates in our estimate. The annual marginal emission rates that we use for New England, New York and PJM electrical control areas are shown below.

Table 8. Annual Marginal Emission Rate

Pollutant	New England (lb/MWh)	New York (lb/MWh)	PJM (lb/MWh)
SO_2	4.45	4.45	11.22
NOx	1.79	1.79	4.75
CO_2	1,263	1,263	2089

For our high estimate of potential emission reductions from imposing output based standards on the highest emitting fossil resources, we compare 1998 emission rates of the affected resources with emission rates allowed under the policy. For our high estimate of potential emission reductions associated with an emission performance standard we project system average emissions for 2005 under the assumption that new load growth is met with new gas generation.

Low Estimate of Potential Emission Reductions

For our low estimate of policies that displace generation we do not hold the regional generating mix fixed; we consider the effect of different policies on new entrants. Specifically, we anticipate that policies that introduce various types of new generating capacity (e.g. RPS) or demand reductions (e.g. SBC for energy efficiency) will slow down the rate of market entry of the substantial number of new gas fired plants that are currently planned or under construction. That is, at any point in time, there will be a smaller amount of new gas capacity in operation, and the “displaced generation” will be the generation that would have been produced at those gas fired plants.[63]

In the Northeast, virtually all new plants projected to come on line during the next decade are combined-cycle natural gas plants. Thus, when calculating potential emission

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[62] An alternative method for determining annual marginal emission rates for each control region would be to use the PROSYM electric system modeling software. To do this, we would simulate annual electricity generation in the region based on expected demand patterns. Then we would simulate generation assuming that demand in all hours is two percent greater than in the base case. This increases the operation of the marginal unit in some hours and brings on a new marginal unit (relative to the base case) in other hours. We would then sum total system emissions for both cases and calculate the difference. The difference in emissions between these two scenarios divided by the difference in generation would give us the “annual marginal” emission rate. It would be a weighted average of the marginal emission rate, reflecting the difference in marginal emissions during peak and off-peak periods.

[63] There are, of course, many subtleties to this simple view of displaced gas fired generation on a mWh for mWh basis – dealing with differences in capacity, differences in the timing of generation, and various system operating constraints. These more complex effects are generally analyzed with electric system simulation modeling. Such modeling is beyond the scope of this project.

reductions over the long term, we use the emission rates for this type of plant. These rates are shown in the table below.

Table 9. Emission Rates for New Generation

Pollutant	New CCCT (lb/MWh)	New CT
NOx	0.10	0.25
SO_2	0.01	0.03
CO_2	800	1,450

For our low estimate of potential emission reductions associated with an emission performance standard we project system average emissions for 2005 under the assumption that proposed gas capacity in each region runs at a 70% capacity factor, thus meeting new load growth and displacing some system average generation mix as well.

2. Discussion of Specific Emission Reduction Estimates

Energy Efficiency

There are many factors that will affect the emission reduction potential of energy efficiency programs. The most important factors are (1) the amount of investments made in energy efficiency, (2) the amount of efficiency savings that can be achieved as a result of those investments, and (3) the type of power plants that are displaced as a result of those efficiency savings.

With regard to the first factor – the amount of investments made in energy efficiency – we apply the level of SBC currently in place in Connecticut to the entire Ozone Transport Region. We have chosen the Connecticut SBC amount because it is the highest in the region, and thus reflects the highest amount that has received political acceptance to date. If a lower SBC is used, then the results presented here could be scaled down linearly. Applying the Connecticut SBC charge of $3.0/MWh to the retail electricity sales in all of the OTC states in 2005 would result in a total of $1,601 million per year for energy efficiency investments.

With regard to the second factor – the amount of efficiency savings that could be achieved from these investments – there are many variables that could influence the amount of savings. Program designs, program marketing techniques, choice of efficiency measures, amount of incentive payments used to induce customer participation, delivery methods, administration costs, collaborative input, and choice of program administrator can all effect the amount of savings available from a dollar spent on efficiency programs. In our analysis we assume a single cost of saved energy figure to capture these many variables. In other words, the cost of saved energy (in $/MWh) indicates the amount of efficiency savings that can be achieved from a given amount of efficiency investments.

The energy efficiency programs in Connecticut in 2000 were able to achieve program savings for a cost of $23/MWh[64]. This figure is less than costs recently incurred in Massachusetts ($33/MWh), but higher than costs recently incurred in Vermont ($16/MWh). For the emission reduction calculation, we assume that all of the efficiency investments throughout the Ozone Transport Region could achieve savings at the costs experienced in Connecticut in 2000. The Connecticut efficiency programs are relatively mature and have benefited from public input through the collaborative process. This cost of saved energy is clearly achievable, and is typical of mature efficiency programs elsewhere.[65] Therefore, if $1,601 million is invested throughout the OTR per year, and saves energy at a cost of $23/MWh, there would be a total of roughly 69,600 GWh of efficiency savings in the region each year.

In order to make the efficiency emission reduction potentials consistent with those of the other policies discussed in this chapter, we need to make one more assumption about savings. Efficiency measures installed in any one year will continue to result in savings throughout the operating life of that measure (which is 14 years on average). Thus, the amount of efficiency savings in any one year will be the result of the cumulative number of efficiency measures installed over the previous years. For our purposes here, we estimate the amount of efficiency savings, and associated emission reductions, that would be obtained as a result of three years of energy efficiency investments over the period of 2003 through 2005. (This is consistent with our methodology for emission reduction potential from the RPS.) After three years of installations, the efficiency programs assumed here would save a total of 208,800 GWh per year.

With regard to the third factor – the type of power plants that are displaced as a result of those efficiency savings – we have developed a low and a high case to indicate the potential range, as described in the previous two sections. The low case is based on the assumption that the efficiency savings displace only the generation from a natural gas combined-cycle unit, and the high case is based on the assumption that the efficiency savings displace generation from existing power plants in the Ozone Transport Region. Applying the 208,800 GWh of efficiency savings to the low and high case emission factors described above leads to the following results:

- potential SO_2 reductions: approximately 70 to 56,700 tons;
- potential NO_X reductions: approximately 700 to 23,700 tons; and
- potential CO_2 reductions: approximately 5.76 to 12.10 million tons.

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[64] It is important not to compare or confuse the cost of saved energy (in $/MWh) with the SBC amount (also in $/MWh). The denominator in the cost of saved energy refers to the amount of efficiency savings. The denominator in the SBC refers to the total retail electricity sales. The former is an indication of how much efficiency can be achieved from a given investment. The latter is simply an measure of how much revenues can be generated to support energy efficiency activities.

[65] For example, from 1990 through 1998 energy efficiency programs in California have resulted in roughly $3 billion in net benefits, at an average cost of saved energy of $25/MWh. See Natural Resources Defense Council, *Energy Efficiency Leadership in a Crisis*: *How California Is Winning*, August 2001.

Factors That Will Influence Emission Reduction Potential

Here we provide a little more detail on the factors that will most influence the emission reduction potential of energy efficiency programs.

Funding for efficiency initiatives. All else being equal, more funding will lead to more efficiency savings and more emission reductions.

Choice of efficiency measures. Different types of electricity end-uses have different electricity demands, and thus different potential for efficiency savings. Those measures that operate frequently throughout the day and the year will tend to offer greater savings and greater emission reduction potential than those that operate less frequently. In addition, measures that represent a large portion of the total electricity demand also provide greater potential for savings and emission reductions. Examples of end-use types with relatively high emission reduction potential are: lighting, air conditioning, water heating, space heating and refrigeration.

Peak savings versus energy savings. Some efficiency programs are designed to save energy throughout the day and throughout the year, while others are designed to save energy only during peak periods or to shift energy demand from peak to off-peak periods. The advantage of "peak-clipping" or "peak-shifting" programs is that they tend to save energy when it is most cost-effective to do so, and they offer the potential to defer the construction of new power plants that are needed to serve peak loads. However, these programs might save very little, if any, energy (in MWh) overall because they miss the opportunities for reducing demand during the many off-peak hours of the year. In general, those programs that save the most amount of energy throughout the year are more likely to also achieve the greatest amount of emission reductions.

Financial incentives to customers. Many efficiency programs offer financial incentives (e.g., rebates) for customers to purchase and install efficiency measures. These financial incentives are often required to overcome the many market barriers that inhibit customers from investing in energy efficiency measures on their own. Significant financial incentives are often necessary to achieve substantial efficiency savings. However, it is important to avoid paying more than necessary to achieve customer participation, in order to be able to make the greatest use of available funds. Efficiency programs will achieve the most energy savings, and thus the most reductions in emissions, if they strike the appropriate balance between motivating customers with financial incentives and keeping those incentives as small as possible.

Choice of program administrator. As described in Section 1.4, electric utilities have a powerful financial incentive to promote electricity sales, and a financial disincentive to achieve efficiency savings. Efficiency programs are likely to be more successful in saving energy, and thus reducing emissions, if they are administered by an entity that does not have a financial interest in electricity sales, and in fact has the reduction of electricity demand as its core mission. In addition, independent efficiency administrators do not require shareholder incentives in order to implement successful programs, thus allowing more funds to be directed towards saving energy.

Accounting for the environmental benefits of energy efficiency. Energy efficiency programs are screened and prioritized using cost-benefit tests. If those tests were to properly account for the environmental benefits of efficiency programs, then the efficiency program administrators might place greater emphasis on those efficiency measures and programs that result in reduced air emissions. If the environmental benefits of energy efficiency programs were properly accounted for it may be possible to obtain political support for increased funding of energy efficiency programs, which would result in greater air emission reductions.

Load Response

We have performed an estimate of potential emissions impact associated with an economic load response program.[66] To arrive at the estimate, we assume economic load response reduces peak load by five percent for fifty hours in a year. We applied this assumption to the National Electric Reliability Council's projection of peak load in the three electrical control regions for 2005. The assumption of fifty hours per year may be low for the year 2005, but we base the estimate on results of economic load response programs in summer 2001. The environmental impacts of the economic load response programs will depend on a number of factors including what resources are allowed to participate in economic load response programs (e.g. New York prohibits diesels in economic load response), what the emission characteristics of those resources are, and what type of generation they are displacing.

For our estimates, we assumed that 2/3 of the load response would come from diesel generation. This assumption is based on ISO New England's projection in early 2001 that 2/3 of the load response in their programs would be from customer- sited generation and based on our understanding that most customer-sited generation is currently diesel generation.[67] Further, we assume that the load response displaces a new combined cycle turbine to reflect that load response, with its anticipated impact on peak prices, will affect new entry into wholesale electricity markets. Our high estimate reflects an assumption of high emissions from distributed generation. Our low estimate reflects some improvement in the emissions profile of distributed generation due to emission standards and reliance on lower emitting distributed generation.

SBC Renewables

The air-quality benefits of a renewables SBC program are difficult to quantify without extensive, state-specific research. The area that needs the most research is the state's

[66] As noted in Section 2, ISO New England has projected emissions impacts associated with its "reserves" load response program. We have not reviewed the model or modeling assumptions that ISO New England used. We do note, however, that an accurate estimate of potential emission reductions would have to estimate emissions from the operation of customer site generation. ISO New England's estimate of emission reductions looks only at avoided emissions from large central generating stations, but not at emissions from customer site generation, which would offset the estimated emission reductions to some degree.

[67] Unfortunately, it is very difficult to get data on actual customer site generation. Although a number of organizations, including the Northeast States for Coordinated Air Use Management, are working to gather such data.

particular allocation of funds. Most states strive to fund a range of technologies, including emerging technologies (closer to the R&D stage) and more mature ones. Thus only a portion of the money distributed goes to projects that provide near-term air quality benefits.

We do not calculate potential reductions from a renewables SBC here, however, with targeted research a state could estimate emission reductions from projects receiving SBC funds. This could be done by obtaining operating data from the projects (or estimating these data), and multiplying kWhs generated by a system marginal emission rate. However, where other subsidies and incentives are available, regulators should take care in concluding that SBC funds are solely responsible for emission reductions. To use the methodology laid out here and claim that the SBC "resulted in" or "achieved" the emission reductions would probably be misleading – especially in the presence of an RPS. A calculation of the cost of emission reductions based only on SBC costs would be equally misleading. Phrases such as "the SBC contributed to" would be more appropriate.

Renewable Portfolio Standards

As discussed in Section 2.2, there are several challenges to calculating potential emission reductions from RPSs. First, it is difficult to know what portion of the new renewable projects developed in a state would have been developed absent the RPS, and this is especially problematic in states that also subsidize renewables in other ways. Here, we estimate an upper bound of RPS emission reductions by assuming that all projects developed after the establishment of the RPS are the result of the rule.

Second, many states do not explicitly require new renewable generation in the RPS; rather, they simply set the standard at a level believed to be higher than the current percentage of renewables in the state. In order to calculate emission reductions in this situation, one must first inventory the existing renewable generation in the state and then determine the amount of new renewable generation the standard will produce.

We model a case in which the specifics of the Massachusetts RPS are adopted across the OTR. We model the Massachusetts rule, because it is one of the more aggressive RPSs in the country and because it explicitly requires new renewables. As shown in Table 6, we calculate 2005 NOx reductions in the range of –400 tons to 7,700 tons. These reductions result from an increase in renewable generation equal to two percent of total regional energy sales. The Massachusetts RPS requirement rises to four percent in 2009, so potential regional reductions in that year would be slightly more than twice the 2005 reductions.

The figure "(400)" indicates a potential increase of 400 tons per year. This increase is due to the biomass component of the RPS. We assume that 10 percent of the RPS is met with biomass generation, emitting NOx at an average rate of 1.75 lb/MWh. (Massachusetts regulators have proposed an RPS biomass NOx limit in the range of 1.5 to 2.0 lb/MWh, and we follow the cost benefit report performed to support the development of the rule in assuming a biomass NOx rate of 1.75 lb/MWh.[68]) As

[68] See: Cost Analysis Report at: http://www.state.ma.us/doer/rps.

discussed above, our low estimate of emission reductions is based on the displacement of generation from a new combined-cycle gas turbine with NOx controls (a NOx rate of 0.10 lb/MWh). When this technology is assumed to be displaced, even 10-percent compliance with biomass results in increased emissions.[69] There are no increases in SO_2 or CO_2, because emissions of these pollutants from biomass plants are assumed to be negligible.

One important distinction regarding the RPS figures in Table 6 relates to exactly what is being measured. The potential reductions here are avoided emissions in 2005 from regional implementation of the Massachusetts RPS. Consistent with the Massachusetts rule, our OTR RPS is assumed to start in 2003, requiring one percent of suppliers' portfolios to be from new renewable projects. In 2004 the requirement rises to 1.5 percent. Note that the renewable projects installed in these years would still be operating in 2005, contributing to the emission reductions shown in Table 6. Thus, the potential emission reductions cited in 2005 are the cumulative result of an RPS requirement that has been in effect – and increasing – since 2003.

Purchasing requirements

For the state renewable purchasing requirement we have estimated the emissions impacts of a 5% new renewable purchase requirement in 2005 excluding biomass. The choice of a 5% new renewable purchase requirement is based on a recent legislatively mandated study in the state of Massachusetts regarding the feasibility of a 10% renewable purchase requirement.[70] The study considers a 10% renewable purchase requirement, as well as a 10% *new* renewable purchase requirement and concludes that the requirement to purchase new renewables will have a substantially larger beneficial impact on the penetration of renewables. The study considers the feasibility of a continuous 10% renewable purchase requirement between 2001 and 2010, with a gradually increasing proportion of that requirement coming from new renewables. In 2005, the new renewables would satisfy 50% of the total 10% renewable purchase requirement, or 5% of the total purchase.[71]

To determine the potential magnitude of the 5% purchase requirement we have assumed that state agency purchases as a percent of total state consumption are consistent

[69] Note that there are also potential net emissions from landfill gas generation – a technology included in most RPSs. However we assume that (1) the alternative to power generation at landfills is flaring of byproduct gases and that (2) NOx emissions from flaring are roughly equivalent to those from generation. Thus we assume no net NOx emissions from landfill gas generation. Again, we follow the Cost/Benefit study performed for the Massachusetts Division of Energy Resources in this assumption.

[70] "Commonwealth Renewable Energy Procurement: A Report to the General Court on the Viability, Effectiveness, and Cost of Minimum Renewable Energy Purchases by State Agencies," Executive Office of Administration and Finance (Operational Services Division) Office of Consumer Affairs (Division of Energy Resources), Draft Report, December 2001. Final anticipated early 2002.

[71] "Commonwealth Renewable Energy Procurement: A Report to the General Court on the Viability, Effectiveness, and Cost of Minimum Renewable Energy Purchases by State Agencies," Executive Office of Administration and Finance (Operational Services Division) Office of Consumer Affairs (Division of Energy Resources), Draft Report, December 2001. Final anticipated early 2002.

throughout the region at 14%. This percentage is based on actual data in Massachusetts, and we were unable to find a ready source of data on the total kilowatthours of state agency electricity purchases for other states in the Ozone Transport Region. Our estimate reflects emission reductions that would occur if the state purchasing requirement did not overlap with any other renewable policies such as an RPS. In other words, we assume that the 5% new renewable requirement for state purchases is over and above any RPS. While it is unlikely that by the year 2005 all states will impose a 5% new renewable purchase requirement over and above any RPS, we found this assumption reasonable for illustrative purposes.

As with other programs, our high estimate reflects displaced system marginal emissions, while the low estimate reflects displaced emissions from a new combined cycle gas unit.

Emission Performance Standard

The potential emission reductions from an EPS are dependent on the size of the region implementing the policy. For example, if only one northeastern state established an EPS, high-emitting generating units in the region would still have ample markets in which to sell their output, and emission reductions would likely be minimal. Here, we estimate emission reductions from an OTR-wide EPS – an area we believe is large enough to have a significant impact on the regional generating mix. Note that emission reductions should not be scaled down to a smaller region in a linear way.

We use regional *average* emission rates as our baseline, because the EPS regulates suppliers' portfolio average resource mix. This means that the nuclear or hydroelectric (baseload) energy a supplier buys contributes to his compliance with the EPS by bringing down his portfolio average emission rate. In this way, the EPS is different from most of the other policies assessed here – policies that reduce *marginal* generation by reducing energy use or adding incremental new generating capacity.

To estimate potential EPS reductions we have constructed high and low emissions scenarios for OTC electricity generation in 2005. In both scenarios, we use NERC assumptions about load growth (1.5 percent per year in New England and PJM and 1.14 percent in New York). In both scenarios we also start with data from EPA's EGRID database on regional generation and emissions by plant in 1998.

In the high emission scenario, we assume:

- load growth from 1998 is met by new combined-cycle gas plants, and
- there are no emission reductions at existing plants.

In the low-emission scenario, we assume that more new gas plants are built than in the high-emission scenario:

- between 1998 and 2005: 10,000 MW of new gas capacity is added in New England; 10,000 MW in New York and 15,000 in PJM,[72]

[72] These figures for gas power plant capacity additions are rough estimates. They represent only about one quarter of total proposed capacity additions. Note also that a substantial portion of this capacity has already been brought on line, and that most of the rest of this is currently under construction.

- all the new gas plants constructed operate at a 70-percent capacity factor and that existing (1998) plants generate the balance of the needed energy, and
- the SO_2 and NO_x emission rates for existing plants are reduced by 10 percent each by 2005.

Using these two scenarios, we compare 2005 emissions to emissions resulting from an OTR-wide EPS at the levels proposed in NESCAUM's model EPS rule.[73] These emission rates are: 4 lb/MWh SO_2, 1 lb/MWh NO_x and 1100 lb/MWh CO_2. The results of this analysis, shown in the table below, are quite useful in evaluating potential EPS rules.

Table 10. Average Emission Rates and Estimated EPS Emission Reductions

Scenario	SO_2	NOx	CO_2
High Emission 2005 Scenario			
Without EPS (tons)	1,668,000	535,000	287,248,000
With EPS (tons)	1,061,000	265,000	291,779,000
Reductions (tons)	607,000	270,000	(4,531,000)
Low Emission 2005 Scenario			
Without EPS (tons)	1,011,000	335,000	260,488,000
With EPS (tons)	1,061,000	265,000	291,779,000
Reductions (tons)	(42,000)	70,000	(31,291,000)

Compared to the high-emission base case, the EPS would result in substantial SO_2 and NO_x reductions, but would not achieve CO_2 reductions. In other words, emissions of CO_2 are *lower* in the *high-emission* based case than allowable emissions under the proposed EPS. In the low-emission base case, the EPS achieves NO_x reductions but neither SO_2 nor CO_2 reductions. CO_2 emissions in the low-emission base case are over 30 thousand tons below the EPS level.

These results imply that the proposed draft EPS levels may not take into consideration enough new (clean) gas capacity in the region. If states plan to move ahead with EPSs, more work needs to be done to identify EPS emission levels that will be meaningful in future years. Specifically, declining EPS levels may be needed to ensure that EPSs are both reasonable in the near-term and effective over the longer term.

Multi-pollutant Output based standards for high emission sources

This policy would be targeted to reducing emissions from the highest polluting sources in the regions. For the estimate of potential emission reductions from requiring the highest emitting generating facilities to meet output based standards, we have reviewed the potential impacts of reducing emission rates from fossil fuel-fired generation units larger than 100 MW in the three electrical control regions. This is a simplifying assumption that all units greater than 100 MW would be affected by such a policy; it does not select units of a certain vintage or units that exceed a certain emission tonnage as a state policy

[73] See: "Model EPS Rule" http://www.nescaum.org/workgroups/energy.html.

is likely to do. However, we believe this assumption serves for an illustrative calculation. As noted in section 2, we assume that this policy would be implemented in the context of existing cap and trade programs rather than instead of cap and trade programs; thus emissions sources that were not affected by the output based standard would continue to have to comply with existing cap and trade programs.

For our high estimate we assume that the fleet of affected units operating in 1998 continues to generate the same aggregate quantity of kilowatthours in 2005 as it did in 1998. Our high estimate for SO_2 and NO_x reflects the difference between region-specific 1998 fossil emission rates for fossil fired facilities 100 MW and larger from EGRID and the emission rates contained in Massachusetts' regulation 310 CMR 7.29. Our high estimate for CO2 reflects a ten percent reduction from the 1998 baseline, consistent with the MA DEP estimate of the impact of the policy on affected sources. We chose this approach instead of simply comparing the required emission rate to regional emission rates because the CO_2 emission rate in the Massachusetts regulations is highly specific to the affected sources. These emission rates are shown in the following table. The table also shows the percentage reduction in emissions rates that MA DEP anticipates from affected facilities in Massachusetts.

Table 11: Emission Rates Reflected in Calculations for Multi-pollutant Output Based Standards – Units Larger than 100 MW

	SO_2 (lb/mWh)	NOx (lb/mWh)	CO_2 (lb/mWh)
New England	8.68	2.72	1740
New York	8.11	2.60	1670
PJM	15.76	4.64	2000
MA regulations	3.00*	1.50	1800
MA DEP estimated percent reduction from historic baseline (1997-99)	50-75%	50%	10%

** The Massachusetts regulations require that affected facilities achieve an SO_2 emission rate of 3lb/mWh using a combination of on-site reductions and trading. Affected facilities must achieve an SO_2 emission rate of 6lb/mWh on-site, and may use trading to achieve reductions from 6lb/mWh to 3lb/mWh.*

For our low estimate of potential emission reductions from imposing output based standards on the highest emitting fossil resources, we assume that more new gas plants are built than in the high-emission scenario, as we did for the EPS low estimate (see above). This results in reduced operation of the fleet of affected units that operated in 1998. However, to reflect the fact that this policy would only apply to a subset of generating facilities, unlike the EPS, we reduce the electrical output of the "affected units" pro rata in proportion to the reduction in output from all 1998 units that would occur under the higher gas penetration scenario.

Multi-pollutant Cap & Trade Program with Output based Allocation

This policy would be targeted to reducing emissions from the highest polluting sources in the regions. We have prepared estimates of the potential SO_2 and NO_x emission reductions from the implementation of this policy. Our estimate for this policy reflects a similar method to that in the previous section; however, there is one primary difference: we look at units larger than 25 MW. As in the previous section, this is a simplifying assumption that all units greater than 25 MW would be affected by such a policy; it does not select units of a certain vintage or units that exceed a certain emission tonnage as a state policy is likely to do. However, we believe this assumption serves for an illustrative calculation.

The New Hampshire DES has provided an estimate of the potential CO_2 emission reductions associated with OTR wide implementation of a policy that would require reductions from the utility sector to 1990 emissions levels. The New Hampshire DES estimate was calculated by subtracting the 1990 emissions for states in the OTR from region-wide 1998 emissions from EGRID. We have not independently verified this calculation, but we include it for illustrative purposes. Table 12 shows the emission rates used in our calculations.

Table 12: Emission Rates Reflected in Calculations For Multi-pollutant Cap and Trade – Units Larger than 25 MW

	SO_2 (lb/mWh)	NOx (lb/mWh)	CO_2 (lb/mWh)
New England	8.24	2.64	N/A
New York	7.56	2.54	N/A
PJM	15.07	4.67	N/A
NH regulations	3.00	1.50	1990 levels

OTC NOx Budget Program

For the estimate of potential emission reductions from requiring applicable facilities to meet the seasonal caps with trading established by the OTC NO_x Budget Program, we have reviewed the potential impacts of reducing fossil emissions in the three electrical control regions. Our estimate reflects the difference between region-wide 1998 emissions during the ozone season for fossil fired facilities 15 MW and larger from EGRID and the Phase III emissions budgets. For our estimate of potential SO_2 emission reductions, we subtracted the Clean Air Act Title IV Phase II allocations for OTR States from the region-wide 1998 baseline emissions.

DG standards

Calculating the expected costs or benefits of DG emission programs would entail a number of complex assumptions about technology adoption under different regulatory scenarios, market prices and DG operation patterns. The first difficulty is in establishing cost and emissions baselines – how much DG and what kind of DG is installed in a "business as usual" scenario? The second difficulty comes in predicting market prices and how owners of DG will operate the units in response to those prices. Where prices are more volatile (or persistently high, as in a region short on supply), one would expect DG to be operated more hours per year than in other regions. One would also expect more DG units to be installed amid volatile prices than elsewhere. Thus, even where the fleet of DG is known with some certainty, the operation of that fleet is a rather complicated modeling question.

We do not model potential emission reductions from DG standards or certification programs. We know of only one study that has attempted to model this – a study released in draft form in 2001 by the Natural Resources Defense Council. See discussion in the Section on DG Emission Programs.

Information disclosure

Estimating potential emissions reduction from an information disclosure policy would be very difficult. Information disclosure policies were essentially adopted as consumer protection policies to ensure that customers had a consistent source of data available and that such data was based on accurate information. No estimate because information disclosure in itself is unlikely to produce emission reductions over and above emission reductions due to green marketing and RPS.

3. General Method – Sources of Data

Sales – EIA 1999 sales data

Demand growth rates – NERC projection of summer peak demand

Historic Generation – EGRID 2000

Future total generation by region – NERC projection of summer peak demand

Regional average emission rates, average fossil emission rates, and unit-specific emission rates are all from EGRID 2001. Regional fuel-specific emission rates for coal, oil and gas are from EGRID 2001. The emission rate for wood waste is from *Reducing Greenhouse Gases and Air Pollution: A Menu of Harmonized Options,* published by STAPPA/ALAPCO in 1999. Emission rates for diesel generators are from *Distributed Resources and Their Emissions: Modeling the Impacts,* a draft report issued by the Natural Resources Defense Council in 2001. Emission rates for new combined cycle gas turbines and new combustion turbines are based on air permit information.

Annual marginal emission rates for each region were calculated based on the percent of time that different fuels are on the margin. For New England, this information is available from ISO New England's Annual Market Report, issued August 1, 2001.[74] [75]

[74] ISO New England, Annual Market Report May 2000-April 2001. August 1, 2001. Section 3 – Technical Review, pages 52-55.

[75] The New England market data shows hydro electric generation plants on the margin a substantial portion of the time. We have allocated those hours pro rata to the other types of generation capacity because the hydro units have energy storage capability. If they were to operate less in any particular hour, then the water not used would typically be used to generate electricity in a future hour.

For the PJM Interconnection, this information is available from the State of the Market Report, issued June 2001.[76]

Table 13: Percent of Time Specific Fuels Are on Margin

Fuel Type	New England	New York	PJM
Coal	13	N/A	48
Natural Gas	47	N/A	18
Nuclear	2	N/A	2
Petroleum	25	N/A	31
Wood Refuse	13	N/A	-
Miscellaneous			1

[76] PJM Interconnection, L.L.C. Market Monitoring Unit, PJM Interconnection State of the Market Report 2000. June 2001. Page 17.

IV. Conclusions from the Survey

In this section we present some observations and conclusions from the survey phase of this project.

As a general observation, the success of certain programs is contingent upon implementation of the program on a regional or national basis. For example, a single state implementing a renewable portfolio standard or an emissions performance standard is not likely to have a significant impact on state or regional emissions from the electricity industry. This is in large part due to the regional nature of electricity markets. Nevertheless, individual states' implementation of these policies is a step toward policies that can be very effective on a regional level. One of the factors affecting regional importance is whether it applies at the retail level. Regional implementation is particularly important for programs that apply at retail level due to the regional nature of electricity markets and electrical control system operation. In the absence of a regional policy, generation resources that do not meet the requirements established in one state's policy can easily be sold to customers in other states; as a result the state's retail policy may not affect the operation of specific generating resources or types of generating resources.

Regional coordination among environmental regulators in the Ozone Transport Region will enhance the effectiveness of programs where the success of the program in achieving emissions reductions shows a strong correlation to a regional approach. EPS is just one program that works better on a regional or national basis.

Environmental regulators should continue their efforts to integrate environmental and energy policy at both the State and regional levels by working with energy agencies and power system operators on overlapping policies and programs. Coordination among environmental and energy regulators has become increasingly important as environmental and utility (or economic) regulators pursue policies within their own jurisdiction that affect other policy pursuits in other jurisdictions. For example, the push among state and federal utility regulators for load response that will enhance the competitiveness of electricity markets has significant potential ramifications for meeting air quality standards due to the potential for increasing the operation of certain highly polluting distributed resources. Close coordination among environmental and utility (or economic) regulators will enhance the ability to achieve both environmental and economic policy goals. Further, coordination with other entities, such as ISOs will enhance the effectiveness of policies and ensure that power system operation is not at odds with state and regional policy goals. For example, in many instances the system operators' decisions about the operation of the electrical power system may hamper the achievement of environmental policy goals or environmental policy could be enhanced by understanding the details of power system operation.

Energy Efficiency

- Efficiency represents a "no regrets" approach to emission reductions because it is a worthwhile investment in its own right. Energy efficiency programs are designed to cost less than the costs of electricity generation, transmission and distribution. Therefore – unlike most other means of reducing air emissions – energy efficiency can achieve emission reductions with net negative costs (i.e., economic savings) to society.

- There is a large potential for reducing air emissions from energy efficiency programs, at negative costs to society. There is an even larger potential for reducing air emissions from energy efficiency programs, at relatively low positive costs to society.

- Efficiency programs offer a variety of societal benefits beyond the reduction in air emissions and the reduction of electricity costs, including: increased electricity reliability, less reliance upon imported oil, reduced water, oil and gas consumption, improved working conditions and performance in local businesses, economic development of local businesses, and a variety of benefits to low-income customers.

- System benefit charges have been applied in nearly every state in the Ozone Transport Region, and represent a politically acceptable and highly feasible option for reducing air emissions. However, the amount and duration of the SBC funds vary widely among states within the region. The SBCs established to date have not set aside enough funds to develop the full potential for cost-effective energy efficiency in the region. Therefore, there remains a large amount of untapped, cost-effective, energy efficiency that could be used to reduce emissions.

- Utility-run efficiency programs can be significantly hampered by the fact that electric utilities' profits increase with higher sales and decrease with lower sales. Collaborative processes offer the potential for significant stakeholder input to the design and implementation of energy efficiency programs. Independent agencies offer the potential to avoid the utilities' financial disincentive to energy efficiency, and to design and implement programs through an agency dedicated to maximizing energy efficiency savings.

- While electric utilities have traditionally been responsible for their own energy efficiency programs, there has been an increasing trend toward establishing consistent programs across each state, increasing stakeholder input through collaborative energy efficiency initiatives, and shifting the responsibility for energy efficiency to independent agencies.

- SBCs are usually not applied to municipal electric companies or rural electric cooperatives. They are often not applied to gas companies, and they are never applied to oil companies. These other entities represent missed opportunities that could be tapped to achieve more energy efficiency savings and greater emission reductions.

- Environmental regulators need to educate legislators on the clear connection between energy efficiency/renewable energy programs and air quality.

Load Response Programs

- Load response is critical to achieving efficient wholesale markets for electricity and could provide some significant benefits for operation of the interconnected bulk power system. However, load response could pose a significant challenge for environmental regulators seeking to meet air quality standards if it causes an increase in operation of, and emissions from, highly polluting distributed generation.
- Efforts to limit the emissions associated with load response programs can include prohibiting the use of dirty diesel generation in economic load response, requiring that distributed generation meet certain emission standards, and ensuring that certain low emissions load response options are viable. Such efforts can prevent load response from creating a set-back in achieving environmental policy goals and ensure that load response is a viable component in meeting economic policy goals.

Systems Benefit Charges for Renewables:

- Regulators should clearly define the purpose of a renewables SBC and target funding accordingly. For example, the SBC could be designed to complement an RPS, by funding less mature and higher-cost technologies. Alternatively, an SBC could be designed to achieve maximum emission reductions by targeting the lowest cost and lowest emitting technologies. An SBC could also strive to support a mix of these two technology types.
- State's can track the extent to which their SBC is contributing to emission reductions by collecting information on the annual operation of renewable projects that have received SBC funding.

Renewable Portfolio Standards

- There are potentially significant costs associated with verifying compliance with an RPS, as regulators must verify that retailers have purchased blocks of power generated by renewable resources. To the extent that states share these costs in a regional information system, per-state costs will be lower.
- From the perspective of air emissions, the selection technologies eligible to meet an RPS is important. Biomass plants can have significant NO_x and CO_2 emissions, depending on the fuel source and plant operating conditions. Landfill gas plants emit NO_x, however landfills without generators generally flare by-product gases (producing NO_x), so generators in effect product NO_x-free or very low-NO_x kWhs.

State and Local Purchasing Requirements

- State and local purchasing requirements that focus on the purchase of renewables that are incremental to other policies, such as a renewable portfolio standard, can spur the market for renewables.
- State and local purchasing requirements that focus on the purchase of new renewables, rather than existing renewables, can provide a strong push for renewable markets and result in emission reductions.
- State and local purchasing requirements can be most effective if they include a financing mechanism and/or are part of an established overall policy goal.

Emission Performance Standards

- The effectiveness of an EPS in reducing regional emissions is dependent on the size of the region implementing the rule. If only one state implemented an EPS, generating companies with high-emitting units would have ample other markets to which to sell output, and there would be little reduction in unit utilization.
- Like the RPS, there are potentially significant costs associated with verifying EPS compliance. If states share these costs in a regional information system, per-state costs will be lower.
- States going forward with an EPS should pay careful attention to planned capacity additions when setting EPS levels. The significant amounts of planned new capacity are likely to bring regional average emission rates down considerably, potentially rendering an EPS meaningless over the medium to long term. Declining EPS rates may be needed to make an EPS both reasonable in the near term and effective over the long term.
- The success of EPS hinges on the existence of a central source of reliable and consistent data, such as a GIS.

Multi-pollutant Output Based Emissions Standards for High Emission Generation Sources

- Massachusetts' multi-pollutant emission standards for the oldest and dirtiest generating sources complement, but do not replace, the state's cap-based emission regulation programs.
- Programs that focus on achieving emissions reductions from existing, high emission electricity generation sources are very effective in reducing emissions from the electricity industry. Such programs are a useful tool for an individual state or group of states to control emissions from a subset of large point sources representing high rates and absolute levels of emissions, and/or to address local

air quality impacts. Such programs are consistent with competitive wholesale electricity markets.

- Multi-pollutant regulatory programs permit a comprehensive assessment of compliance strategies and the likely compliance costs for an individual generation source, and are consistent with competitive wholesale markets and sound business practices.

- Output based emissions approaches, whether in a rate-based program or in an allocation under a cap-based program, will provide financial incentives that will reward individual sources for improving generation efficiency, and that will provide an economic advantage in a competitive wholesale electricity market to those facilities that are more efficient. Overall increases in the efficiency of electricity generation as a result of using output based standards and allocations will generate ancillary environmental benefits such as reduction in any uncapped air emissions (e.g. CO_2, mercury, toxics, reductions in solid waste, reductions in water consumption and discharge, and others).

- Environmental regulators should continue to design emission reduction programs that focus on reducing emissions from regulated emissions sources, in addition to supporting efforts to promote energy efficiency, renewables, and regulation of new emission sources.

Multi-pollutant Cap & Trade Program with Output Based Allocation

- Cap & trade programs with output-based allocations, such as New Hampshire's, can be more cost-effective in achieving a given level of state- or region-wide emission reductions than rate-based programs targeting specific sources.[77]

- Multi-pollutant regulatory programs permit a comprehensive assessment of compliance strategies and the likely compliance costs for an individual generation source, and are consistent with competitive wholesale markets and sound business practices.

- Output based emissions approaches in an allocation under a cap-based program will provide financial incentives that will reward individual sources for improving generation efficiency, and that will provide an economic advantage in a competitive wholesale electricity market to those facilities that are more efficient. Overall increases in the efficiency of electricity generation as a result of using output based standards and allocations will generate ancillary environmental benefits such as reduction in any uncapped air emissions (e.g. CO_2, mercury, toxics, reductions in solid waste, reductions in water consumption and discharge, and others).

[77] It is important to keep in mind the purpose of individual programs. For example, certain rate-based programs are required by federal programs or state law, or are established to address the local air quality impacts of specific resources as well as broader regional impacts.

NO_x Budget Allocation

- Without specific initiatives (i.e., set-asides) to include energy efficiency programs and renewable resources in NO_x budget programs, emission reductions from these programs will result in reducing the overall cost of compliance with the NO_x budget program rather than in additional actual emission reductions from the electricity sector.

- Output based allowance allocation will provide financial incentives that will reward individual sources for improving generation efficiency, and that will provide an economic advantage in a competitive wholesale electricity market to those facilities that are more efficient. Overall increases in the efficiency of electricity generation as a result of using output based standards and allocations will generate ancillary environmental benefits such as reduction in any uncapped air emissions (e.g. CO2, mercury, toxics, reductions in solid waste, reductions in water consumption and discharge, and others).

Distributed Generation Programs

- Environmental regulators must take specific steps to prevent the growth of emissions from non-affected sources that are not included in State emissions reductions programs, such as distributed generation.

- States should adopt emissions certification processes for clean distributed generation. Streamlined permitting creates incentives for the use of clean units and lowers permitting costs to both consumers and regulators.

- States should also give serious consideration to emission standards for distributed generation that close any loopholes in state permitting rules. Part of this effort should be the collection of information from all available sources on the proliferation and operation of distributed generation and associated emissions.

Information Disclosure

- Information disclosure in an of itself is not likely to lead to emission reductions incremental to those that are likely to occur through the operation of market forces and the marketing of “green electricity” to retail consumers. Information disclosure is an important consumer protection policy and will enhance the success of policies such as the Renewable Portfolio Standard, and state purchasing requirements.

- The success of information disclosure hinges on the existence of a central source of reliable and consistent data such as a Generation Information System.

V. Suggestions for Further Work

Criteria for Prioritizing Additional Analysis

Below, we identify criteria that could be used in prioritizing policy areas for more specific case-study analysis in the second phase of this work. These suggestions are not intended to indicate that a particular program should be developed on a regional basis by OTC, only that it merits further study. In reviewing programs to identify promising areas for further study we have emphasized qualitative criteria, since there are not currently readily available quantitative criteria that permit comparison across different programs.

As discussed in Section III, we developed illustrative estimates of potential emission reduction from the stand-alone implementation of many programs; however, the development of other quantitative criteria must be reserved for a different study. Based on these criteria, we suggest a number of different programs or program aspects that are worthy of additional and more detailed review.

1. ***Novelty and innovation.*** Policies that have not been studied extensively in the past, that represent innovation over previous policy designs, or for which new data is available should be preferred to those that have already been studied extensively. In addition, certain policy aspects that have not been previously considered, for example a particular focus on air quality impacts, could be good candidates for more specific study.

2. ***Emission reductions.*** Policies that could potentially achieve significant emission reductions should be preferred to policies with more limited effects in this area. Our illustrative calculations are intended to provide one method of comparing potential emissions reductions from a variety of policies on a consistent basis.

3. ***Feasibility.*** Policies with lower administrative costs and complexity, and that are being implemented or under development are judged to be more feasible, and should be preferred to less feasible policies.

4. ***Regulatory coordination.*** Policies that require coordination across regulatory agencies within a single state, within an electrical control region, or across regions, should be preferred to those that do not. Assessment of such policies could provide very useful lessons for future coordination. In recent years, many utility and environmental regulators have found a need for coordination with their regulatory counterparts in their state and throughout their region.

5. ***Regional consistency.*** Policies for which regional consistency is crucial to success should be preferred to those that do not. This criteria is particularly important in the Ozone Transport Region where pollutant transport is a significant factor in states' ability to meet air quality standards. Regional coordination is also becoming increasingly important as Federal energy regulators at FERC seek to establish a single wholesale electricity market comprising New England, New York and the Mid Atlantic States. As electricity markets become more fluid, and transactions occur across greater distances, the operation of individual generating facilities will be

heavily influenced by the regional market. Finally, regional coordination is an important issue as an increasing number of generating units in the region are controlled by owners who own facilities throughout the region or the nation.

6. ***Wide applicability of results.*** Experience developing certain policies will provide useful information for the design and implementation of a variety of other policies. In particular, where the development of a policy has implications for the success of other policies or is closely linked to other policies, its study could provide insights that are applicable in other related policies.

7. ***Consistency with industry trends.*** Study of a policy would be useful where the policy is on the leading edge of addressing industry trends and evolution.

Suggestions For Additional Analysis

The policies that we have reviewed in this survey could all be integral components of regional efforts to achieve environmental and energy policy goals. The Ozone Transport Commission's efforts to review and analyze the programs, and to seek potential areas of improvement and coordinated action, is consistent with regional environmental and energy policy efforts. This sort of integrated approach that includes review of a variety of policies, and considers potential areas for coordination between environmental and energy regulators, is very consistent with the goals established in the recent Climate Change Action Plan of the New England Governors/Eastern Canadian Premiers.[78] Further analysis of certain programs or program aspects in the next phase of this project can contribute to an integrated and coordinated approach such as that recommended in the Climate Change Action Plan for reduction of emissions from the electricity sector and for increased energy efficiency.

Based on the above criteria, we make the following suggestions for possible case studies for the second phase of this project. The policies reviewed in the next phase of this project would not necessarily be selected by the OTC for development and implementation on a regional basis. The purpose of these suggestions is to provide options for further analysis. We present these options for additional discussion and refinement through case studies. As we move to the second stage of the project it will be important to determine a specific focus and scope of the case studies so that they meet the OTC's needs and can be achieved within the scope of the project.

Emission reductions from energy efficiency. Review and analysis of energy efficiency program areas with a specific focus on identifying energy efficiency programs that have the highest potential emission reductions. There has been a great deal of analysis of energy efficiency programs over the past two decades; however, most of that analysis focuses on energy efficiency from an economic perspective. In most instances, the energy efficiency programs fall within the purview of economic regulators (Public Utility

[78] Climate Change Action Plan 2001, New England Governors/Eastern Canadian Premiers, prepared by the Committee on the Environment and the Northeast International Committee on Energy of the Conference of New England Governors and Eastern Canadian Premiers, August 2001 http://www.web.net/~ccnb/publications/CCAPe.pdf

Commissions) and are pursued for the economic benefits to individual customers, and customers as a whole. Although some states have a cost benefit analysis that incorporates environmental criteria, those environmental criteria usually do not differentiate between programs based on their potential impact on operation of the electrical system. Environmental regulators are increasingly being asked to bring their environmental expertise to bear in activities such as determining appropriate distribution of Systems Benefit Charges. Further analysis, that permits a more fine tuned review of the potential emissions reductions associated with different types of energy efficiency measures could be useful in informing environmental regulators' participation in energy efficiency policy decisions.

Relevant criteria: Novelty, emission reduction potential, feasibility.

Alternative delivery of energy efficiency services. The state of Vermont has initiated a new mechanism for the delivery of energy efficiency services: the energy efficiency utility. Also New Hampshire has developed a Pay as You Save Programs (PAYS). The Energy Efficiency Utility is a state-wide entity that develops and implements energy efficiency programs using funds collected from ratepayers by the electric utilities. Because the Energy Efficiency Utility does not also sell electricity it has no disincentives to implement effective efficiency programs. Centralized program development and implementation permits efficiencies that are not possible when programs are developed and implemented by multiple small and large electric utilities. There has been a fair amount of evaluation of the success of this energy efficiency utility (in kWh savings, and costs per kWh saved). The case study would incorporate this analysis and build upon it. A case study of the PAYS program would review program results to date, as well as implementation and coordination issues.

Relevant criteria: Novelty, feasibility, emission reduction potential.

Generation Information Systems. A generation information system on its own will not achieve emission reductions. However, a generation information system is an essential underpinning for effective implementation of such state policies as RPS, EPS and disclosure (which can affect determination of compliance with state purchasing requirements). An effective GIS can greatly facilitate verification of compliance with these state policies. However, the GIS requires the resolution of many complexities including those associated with coordination of a variety of regulatory requirements and needs. With the current FERC push for a single Northeast Regional Transmission Organization, a case study on the development of the GIS for New England could enable environmental regulators throughout the Ozone Transport Region to participate effectively in emerging GIS discussions in the Northeast.[79] Development of the GIS in New England has required significant coordination among utility and environmental regulators, as well as with ISO representatives and other affected entities.

Relevant criteria: Regulatory coordination, regional consistency, wide applicability, industry trends.

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[79] We are using the term "Northeast" here in a fashion consistent with recent FERC's decisions. Thus "Northeast" encompasses New England, New York, and Mid-Atlantic (i.e. PJM) electrical control regions.

Use of Renewable SBC Funds. Regulators have little direct say in what resources within the definition of "renewable" are developed in response to an RPS. However, they do have significant input on what resources are sponsored through allocation of SBC funds. A case study could focus on the role of the SBC relative to the RPS and to air-quality goals and could identify lessons learned about targeting SBC funds in a manner that achieves maximum air quality benefits.

Relevant criteria: Novelty, emission reduction potential, feasibility.

Distributed generation as a load response measure. Customer site generation has historically served a reliability function. However, in the past couple of years there has been a strong push for economic "load response" where customers would use tools including energy efficiency, load management, and on-site distributed generation, to reduce their demand from the electricity grid at peak pricing times. This creates a whole new context for distributed generation and poses significant environmental threat from the possibility that customers could seek to use existing on-site diesel generation for economic rather than reliability purposes. This case study would be particularly timely since many states are considering the adoption of emissions standards for distributed generation and there are a number of complex issues associated with understanding how DG is operated. The Regulatory Assistance Project has just done a comprehensive study and model standard and it would be important to look closely at that to see what useful work could be done to complement it.

Relevant criteria: Industry trend, innovation, regional coordination and consistency, emission reduction potential.

Emission Performance Standards. Emission performance standards represent a new concept in regulation that has been developed in response to electric industry restructuring, the changing roles of state regulators, and the regional nature of the electrical system and pollutant transport issues. While the concept is an interesting one, our initial emission reduction potential estimates indicate that the policy could be more effective if the performance standards identified in the NESCAUM model rule were modified. A case study could look very specifically at the performance standards proposed by NESCAUM and could investigate options for the appropriate basis for an effective EPS across the OTR.

Relevant criteria: Industry trend, regional coordination, emission reduction potential, innovation.

Multi-pollutant Output Based Approaches for High Emission Sources. As indicated in Section III, policies that reduce emissions from existing highly polluting sources have the greatest potential for reducing air emissions because they directly target the existing generation sources with the largest amounts of air emissions. Massachusetts has adopted multi-pollutant output based standards for certain generation stations within the overall cap and trade program in a manner that seeks to address local emissions impacts. New Hampshire is in the process of enacting a multi-pollutant output-based cap-and-trade program. Connecticut has also adopted an emissions reduction policy targeting the oldest and dirtiest fossil fuel-fired generation sources; the Connecticut policy establishes input-based emissions standards. A case study could look at the factors that shaped each of the policies so that other states could learn from experience to date. The case study could begin the process of considering which plants would be most suited for targeted emission reduction policies, what types of standards would be most appropriate, and what level of emission reduction might be achieved.

Relevant criteria: Emission reduction potential, industry trend, regional coordination.

Allowance Allocation: Allowance allocation methods can have a significant impact on the competitive position of different energy sources in a competitive electricity market. A case study could evaluate the relative cost impact of allowance allocation (such as an output based allocation) on different fuel sources and different affected sources in order to consider what impact the allocation would have on overall electrical system dispatch.

Relevant criteria: Emission reduction potential, industry trend, regional consistency

Air Emissions from Distributed Generation. With electric restructuring, concern over the emissions from small, distributed generators (DG) has increased considerably, and much work has been done over the past 18 months to assess the potential profile and magnitude of DG emissions. Emission standards for DG have been adopted or proposed in four states and the Regulatory Assistance Project has released a draft model standard. Each of these five efforts is unique in its approach to the key policy issues involved. One possible case study is a comparison of these five proceedings and their results. This study would explore how regulators in each of the four states approached the task of regulating emissions from DG, what interested parties contributed to the proceeding, and the product of the proceeding. A concise summary of each rule or proposed rule could be provided, outlining the rule's treatment of key issues, such as the establishment of standards versus a technology certification process, the specifics of any emission limits adopted and the treatment of combined heat and power systems.

Relevant criteria: Industry trend, emission reduction potential, regulatory coordination.

Appendix A: Detailed Matrix of Policies and Programs

DEMAND REDUCTION AND ENERGY EFFICIENCY

Program vehicle	Geographic Scope	Program Goal	Organization Providing Service	Program Duration	Primary Regulatory Agency	Emissions Reduction Potential
SBC - Efficiency	CT, DE, DC, MA, MD, ME, NH, NJ, NY, PA, RI, VT	Fixed charge per KWh for efficiency programs, aiming at reducing emissions across the board. Encouraging companies offering services for efficiency	Utility, Collaboration State / Utility, Independent efficiency agency	Amounts adopted for several years (sometimes secured until 2006). Initiated before or as a consequence of restructuring laws or orders.	State Public Service/Utility Commissions	Depending on the size of the charge (from less than 1 mill per KWh to several mills). Potentially high.
Collaboratively Designed DSM	CT, MA, ME, NH, RI	To improve upon utility-run DSM with public and technical input to design	Electric distribution companies	on-going	Collaborators and state PSCs	Moderate to high
Independent Efficiency Agency	VT, ME, MA	To improve upon utility-run DSM through an independent agency	Efficiency utility, Municipal aggregator	Spring 2000, on-going	Legislators, State Energy Office, PSCs	Moderate to high

DEMAND REDUCTION AND ENERGY EFFICIENCY, Cont'd

Program vehicle	Geographic scope	Program Goal	Organization Providing Service	Program Duration	Primary Regulatory Agency	Emissions Reduction Potential
Rate Incentives for Energy Efficiency	CA	Encourage residential efficiency	No rate increase for customers who reduce usage	Starting May '01	PUC	Moderate
Load Response/System Optimization	NE	Use load response to meet reserve requirements	Individual customer load response (including DG)	One year, with likely repeat	ISO NE	Low
Load Response/Economic	NE, NY, PJM	Encourage demand elasticity in wholesale electricity markets.	ISO load response program	One year, with likely repeat	ISO NE, NY ISO, PJM ISO	Low to negative

LOW EMISSION GENERATION - RENEWABLES

Program vehicle	Geographic Scope	Program Goal	Organization Providing Service	Program Duration	Primary Regulatory Agency	Emissions Reduction Potential
SBC - Renewables	Many, including CT, MA, NJ, NY, PA, RI.	Reduce the up-front costs of new renewable projects, supporting long-term technology cost reductions.	Utilities collect funds for distribution via state agency or third party.	Generally 3-10 years	State PUC or Energy Office	Reduction of major pollutants due to displacement
Renewable Portfolio Standards	Many, including CT, ME, MA, NJ, and PA.	Create demand for renewable resources to decrease air emissions and diversify generation resources	Retail electricity suppliers	Ongoing	State PUC or Energy Office	Medium-high
State or Local Purchasing Requirements	MD, NY, and many cities	Mandate minimum proportion of state or locality's energy supply by renewables. Foster energy efficiency in state buildings	State agencies or local governments purchasing electricity and designing buildings	One to nine years	Individual agencies	Medium

AIR QUALITY POLICIES – POWER SYSTEM EMISSION REDUCTION

Program vehicle	Geographic scope	Program Goal	Organization Providing Service	Program Duration	Primary Regulatory Agency	Emissions Reduction Potential
Emissions Performance Standards	CT, MA, NJ	Cap and reduce emissions associated with retail sales.	Retail electricity suppliers	Not yet developed	DEP	Low to high
Multi-pollutant Output-based Emissions Standards Targeting High Emission Sources	MA	Reduce emissions from power plants, and address local air quality.	Affected electric power generators	Emissions reductions beginning 2004	DEP	High
Multi-pollutant Output Based Cap & Trade Program Targeting High Emission Sources	NH proposed	Reduce total tons of emissions from power plants.	Affected electric power generators	Emissions reductions beginning 2006	NHDES	High
NOx Budget Allocation	MA, NH, NJ, NY, others	Pollution prevention and operation of cleaner, more efficient energy sources	Affected electric power generators	2003 on	State DEP	Medium-high
DG Regulations	Texas, California, CT, RAP model rules	Control emissions from use of distributed generation in emergency and economic applications	Owners of distributed generation	TX: June 2001 Others under development	DEP	Medium
Information Disclosure	Many (CT, MA, MD, ME, NJ, NY, RI)	Facilitate customer choice of electricity sources. Disclosure of environmental characteristics of power supply.	Energy service providers	On-going	PUC	Low

Appendix B: STAPPA ALAPCO Multi-Pollutant Strategy Components – Comparison of Approaches

STAPPA/ALAPCO
Multi-Pollutant Strategy Components – Comparison of Approaches
November 29, 2001

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
Applicability	All NO_x Budget Program (NBP) sources: >= 15 MW or >= 250 MMBTU/hr	Six specific power plants in Massachusetts	All existing fossil fuel-burning power plants with nameplate capacity of 25 MW or more.	Coal-fired generating units over 25 MW (all 14 plants, regardless of age)	NO_x - NO_x Budget Program electricity generators (15 MW); SO_2 – Title IV sources	Power plants; Outdated plants - 30 years old or 5 yrs after enactment, must comply with NSPS & req. under Parts C&D- applicable to modified sources	Fossil fuel-fired generating units	Power plants	Combustion units serving electric generators greater than 25 MW (for mercury, all coal-fired combustion units serving electric generators greater than 25 MW)
Pollutants	NO_x, SO_2	NO_x, SO_2, CO_2, future mercury	NO_x, SO_2, CO_2, future mercury	NO_x, SO_2, CO_2, mercury	NO_x, SO_2	NO_x, SO_2, CO_2, mercury	NO_x, SO_2, CO_2, mercury	NO_x, SO_2, CO_2, mercury	NO_x, SO_2, mercury
Emission limitations	Aggregate across state	Facility-specific reductions	Aggregate across state	Statewide mass emissions cap by pollutant for 14 plants; annual report to legis. on tech. & econ. feasibility of controls beyond limits, starting 9/04	Aggregate across state	Aggregate reductions	Facility-specific reductions	National declining tonnage caps (with trading)	National caps

[1] The Clean Energy Group (CEG) is a coalition of electric generating and electric distribution companies that supports environmental and energy policies that are sustainable from both an economic and an environmental perspective. M.J. Bradley & Associates is the facilitator of the Group.

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
Combustion-heat rate efficiency standards							10 years after enactment, existing fossil fuel-fired units must achieve & maintain combustion heat rate efficiency of at least 45%; new units, 50% efficiency (waivers for limited circumstances but require 1.5:1 offset)		
NO_x	7-month non-ozone season program (developed to compliment existing 5-month ozone season program); 0.15 lb/MMBtu avg over 7-month period	1.5 lbs/ MWhr by 10/1/04 or 10/1/06	Annual program; 70% reduction; 3,644 ton cap & trade; 1.5 lb/MWh applied to current outputs by 12/31/06 (90% lower than 1990 emissions)	Cap of 60,000 tons 1/1/07; 56,000 tons by 1/1/09 (78% reduction from 1998 levels)	7-month non-ozone season (1999 heat inputs x 0.15 lbs/MMBtu x growth); starting 10/04	75% reduction from 1997 levels by 1/1/07	90% reduction of what otherwise in flue gas & emission rate no more than 0.15 lbs/mmBTU	50% reduction from current commitments (including implement-ation of NO_x SIP call in eastern U.S., resulting in average emission rate of approx. 0.15 lbs/ MMBtu, by 2008 (2.11 million ton cap)	Phase I: NO_x SIP call starting May 31, 2004; Phase II: 1.87 million ton annual nationwide cap starting in 2008; Phase III: 1.25 million ton annual nationwide cap starting in 2012

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
SO_2	Phase I (all NBP sources): 0.5% sulfur-in-fuel or 0.55 lb/MMBtu by 01/01/02 Phase II (Acid Rain Program sources): 0.3% sulfur-in-fuel or 0.33 lb/MMBtu by 01/01/03	6.0 lbs/MWhr by 10/1/04 or 10/1/06; 3.0 lbs/MWhr by 10/1/06 or 10/1/08	3.0 lb/MWh applied to current outputs by 12/31/06; 75% from Phase II Acid Rain; 87% reduction from current emissions; 7,289 ton cap & trade	Cap of 250,000 tons by 1/1/09; 130,000 tons by 1/1/13 (74% reduction from 1998 levels)	Phase I – 25% below statewide Title IV allocation in 2005 (197,046); Phase II – 50% below Title IV (131,364)	75% reduction from Phase II acid rain levels by 1/1/07	95% reduction from what otherwise in flue gas & emission rate of no more than 0.3 lbs/mmBTU	50% reduction from Phase II acid rain levels by 2008 (4.5 million ton national annual cap); 60% reduction from Phase II acid rain levels by 2012 (3.6 million ton cap)	2 million ton annual nationwide cap starting in 2010
Mercury	No plans currently for one coal-fired power plant in state; CT has focused on mercury reductions from MWCs that go well beyond federal requirement	Feasibility study by 12/1/02; proposed std. by 5/1/03	Emissions testing by 7/1/03; proposed cap by 3/31/04	Report to legislature annually beginning 9/1/02; final recom-mendation by 9/1/05. Recom-mendation focus on controls beyond those achieved incidentally with the SO_2/NO_x controls		90% from 1999 levels by 1/1/07	90% reduction of mercury in fuel (10 years after enactment); EPA to set regs (in 2 years) to ensure that mercury captured through energy conservation, coal cleaning or other is disposed of without transferring	65% reduction (from mercury present in as-delivered coal) by 2008 (26-ton cap); 79-93% reduction by 2012 (5-16 ton cap)	Phase I: 24 ton annual nationwide cap starting in 2008; Phase II: 7.5 ton annual nationwide cap and a 70% facility-specific reduction starting in 2012

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
							hazards, no release of mercury to environment		
CO_2	To address through environmental performance standards (EPS) applied to retail sale of electricity [will also cover NO_x, SO_x, mercury]	1800 lbs/MWhr by 10/1/06 or 10/1/08; emission cap based upon historical emissions by 10/1/04 or 10/1/06	Return to 1990 levels by 12/31/06; (3% below 1999 emissions)	Report to Legislature on utility control recommendations by 3/1/02	Governor's Task Force established in June 2001 to recommend greenhouse gas actions in early 2001	To 1990 levels by 1/1/07	Natural gas existing units - emission rate of 0.9 lbs/KWhr; new units 0.8 lbs/KWhr; Fuel-oil existing units - emission rate of 1.3 lbs/KWhr; new units 1.2 lbs/KWhr; Coal-fired existing units - emission rate of 1.55 lbs/KWhr; new units 1.4 lbs/KWhr	To 2000 levels (with flexibility) by 2008; to 1990 levels (with flexibility) by 2012; to 1990 levels (with only international flexibility measures) by 2015	
Other pollutants		"Reserved" fine particulate & carbon monoxide emission standards	Future particulates, if necessary					CO & PM_{10} incorp. into program (no averaging or trading); CO best combustion practices; PM_{10} annual average emission	

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
								level of 0.03 lbs TSP/mmBtu beginning in 2008	
Status of proposal	Regulations promulgated 12/28/00	Regulation promulgated 5/11/01	Legislation introduced in 2001; amended for 2002; unanimously passed House committee on 11/28/01	Legislative proposal (adopted by Senate)	Regulations drafted, proposal expected fall 2001	Regulations within 2 years (S.556 - if EPA fails to est. regs, each plant must achieve reductions)	2 years after enactment EPA regs for deter-mining initial & continuing compliance, fuel-sampling techniques & emission monitoring techniques to calculate mercury emission reductions	Proposal – no timeline	
Averaging provisions	SO_2: sources may average at facility, but must meet more stringent limits if they choose to do so.	Averaging across units at a facility (all pollutants); limited SO_2 allowance use (see below); offsite reductions acceptable toward CO_2 compliance	Averaging across units at single facility or site or among units at different facilities owned by same company. Combination of minimum on-site mercury re-duction req. &	Annual cap on mass emissions – total for all 14 plants; can average across plants.	Statewide cap and trade program	May allow market-oriented mechanisms (except for mercury)			Trading allowed, including trading with industrial and commercial combustion units that are not electricity generators

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
			limited averaging for mercury						
Use of allowances	NO_x: sources may use NBP allowances or NO_x discrete emissions reduction credits (DERCs) to meet 7-month avg; SO_2: sources may use SO_2 DERCs (1:1 ratio) or SO_2 acid rain allowances (4:1 ratio) to cover difference between Phase I & II limits	SO_2 allowances at a ratio of 3 to 1 may be used for second phase of SO_2 reductions	Allowances for NO_x, SO_2, & CO_2; bonus incentive allowances awarded for local SO_2 reductions, nearby SO_2 allowance purchases, and energy efficiency and renewable energy expenditures	Allowances for in-state reductions only	Allocated 3 years ahead via formula based on highest heat input from previous 3 years. 5% of state budget can be created through out-of-state reductions beyond current requirements, discounted by 3:1 and, for SO_2, forfeiture of federal SO_2 allowances			National banking & trading of allowances	Affected units would receive allowances through an output-based (electricity and thermal production) system that updates every 5 years.
Monitoring requirements	Part 75	Follow Part 75; mercury TBD	Follow Part 75; mercury TBD	Part 75 to be used, but not specified in legislation	Follow Part 75		See timelines box		
Record-keeping & reporting	Annual reports on compliance - NO_x & SO_2	Annual report documenting compliance	Annual report documenting compliance	Part 75 to be used, but not specified in legislation	Report to EPA CAMD		Quarterly – pollutant-specific emission rpt.		

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
Credit for early reductions	Provisions for early in-state reductions of SO_2	Provisions for early SO_2 reductions; CO_2 under consideration	Provisions for banking early reductions for all 4 pollutants	No specific incentives, but all actual/permanent reductions count toward cap	Early reductions eligible to create allowances for 2 years before start of program	Allocate required em. reductions equitably, taking into acct em. reductions before enactment		Rewards for early reductions	
Credit for renewable energy/con-servation	Distributed generation general permit to address CHP & efficiency. Draft rule to integrate with NBP, resource constraints preclude completion.		Incentives for renewable energy and efficiency	No offset for meeting cap, but measures may contribute to meeting cap	3% energy efficiency/renewable energy and 5% new source (3% for SO_2) set asides	Incentives for renewable energy & efficiency	Extension of renewable energy production credit (IRS) to include solar, geothermal; appropriations authorization for demonstration projects for renewables	Rewards for efficiency	
Natural Gas						S.556 - Policies to reduce rate of growth in natural gas consumption	See CO_2 box		
Localized Reductions	Sources must meet Phase I SO_2 reductions on-site	NOx reductions on site; SO_2 reductions to 6 lbs/MWhr on site use of allowances or	Incentives for localized reductions	Local control necessary for ambient stds; can restrict emissions from a plant or limit intrastate	Questions as to whether still need NO_x RACT need to be answered.	Prevent localized adverse effects; ensure reductions in both Eastern & Western			

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
		on site to 3 lbs/MWhr; CO_2 offsite OK		averaging		regions			
New Source Review									Eliminated (replaced by this program)
Permanent emission reductions in future climate change programs							Permanent reductions in CO_2 & NO_x emissions from retiring old units & replace-ment with new ones that meet combined heat-rate efficiency & emission standards (or through non-polluting renewable techniques) credited to utility		
Fees							Tax of \$.30/MWhr of electricity produced on fossil fuel-fired units - for Clean Air Trust Fund for training, econ.		

	Connecticut	Massachusetts	New Hampshire	North Carolina	New York	Waxman H.R. 1256 Jeffords S. 556	Leahy S. 1131	Clean Energy Group[1]	Administration (proposal dated 7/30/01)
							development, carbon sequestration, R & D projects		
Dem-onstration program							Demonstration program to show efficiency & environmental benefits of clean-coal, advanced gas turbines, combined heat & power technology; assistance for workers/com-munities adversely affected by reduced coal consumption		
Carbon sequestration							Authorizes $15 million for research & development		
MACT, Regional Haze (BART), Section 126, NO_x SIP call, NSPS, Title IV NO_x									Eliminated (replaced by this program) (NO_x SIP call and Title IV NO_x, replaced in 2008)