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Energy Ventures Analysis, Inc.
1901 N. Moore Street
Arlington, VA 22209
(703) 276-4005
(703) 276-9514 (fax)
hewson@evainc.com (e-mail)

EVALUATION OF ALTERNATIVE METHODS FOR ALLOCATING CARBON DIOXIDE EMISSION REDUCTIONS IN THE NORTHEAST

Executive Summary

The Regional Greenhouse Gas Initiative (RGGI) is studying policy options for controlling CO2 emissions from electric generating units (EGUs) in New England, New York, New Jersey and Delaware. This paper examines key economic and policy differences between two environmental policy approaches that RGGI may consider: an emissions portfolio standard (EPS) and a conventional cap-and-trade program It compares total compliance costs and related emission allowance allocations by state for alternative EPS and cap-and-trade policies for the nine states participating in the RGGI process and an expanded 12-state region including Maryland, Pennsylvania and the District of Columbia. It also assesses the distribution of carbon reduction liabilities and windfalls for individual power generators under a range of EPS scenarios.

The economic benefits of including full access to carbon sinks and offsets are compelling. A 9-state RGGI cap-and-trade program to reduce emissions to 10% below 1990 levels with full flexibility to offset emissions through carbon sinks would cost $70 million annually, compared to an annual cost of $431 million to achieve a comparable emission reduction without access to carbon sink offsets (see Exhibit 2).

Achieving a 10% reduction below 1990 emissions in an expanded 12-state region would entail annual costs of $2.1 billion without carbon sink credits, and $288 million with full access to sinks and offsets (assumed to cost $5 per ton of CO2.) The much larger quantities of CO2 emissions that must be reduced in the 12-state region and the higher costs per ton of direct CO2 reductions through fuel-switching and similar measures account for these cost differences relative to 9-state estimates.

The analysis compares various emission allocation approaches for meeting reduction targets ranging from returning emissions to 1990 levels to reductions of 10% to 20% below 1990 levels. The allocation methods for cap-and-trade include historic 1990 and estimated 2002 CO2 emissions, and total 2002 fossil fuel consumption by state. The resulting allocation of emission allowances is shown by state for the 9-state and 12-state regions, and is compared with a "fuel-neutral" allocation under an EPS based on total electric generation regardless of CO2 emissions.

This comparison shows that a fuel-neutral EPS approach would reward states (and companies) with relatively high dependence on nuclear and other low- or non-emitting generation sources, while penalizing states and companies with higher utilization of coal-based generation. For example, to stabilize emissions at 1990 levels, New Jersey would be entitled to the equivalent of more than twice the number of emission allowances under a fuel-neutral EPS than under an historic allocation based on actual 1990 CO2 emissions (see Exhibit 4). In the 12-state analysis, the nine participating RGGI states would receive 50% of the total allowances distributed on the basis of 1990 CO2 emissions, with the remaining 50% distributed to Pennsylvania, Maryland and DC. However, under a fuel-neutral EPS approach, the nine RGGI states would receive nearly 57% of the overall EPS allocation, reflecting this region's lower average reliance on coal-based generation.

Substantial differences exist among states in the distribution of electric generation resources and related CO2 emissions. While New York and New England rely on coal for less than 20% of total electric generation, Delaware generates some 70% of its electricity from coal. Similarly, both Maryland and Pennsylvania rely on coal for more than 56% of their generation. The inclusion of Maryland and Pennsylvania within a regional CO2 cap-and-trade program would shift overall compliance costs away from New England, New York and New Jersey under any form of allowance allocation.

There are significant differences among states in the relative shares of emission allowances under alternative allowance allocation methods. To meet a target reduction of returning emissions to 1990 levels, five states – Connecticut, Maine, New Hampshire, New Jersey and Vermont – would benefit most from a fuel-neutral EPS based on total generation. New York, Massachusetts, Delaware and DC would gain most from an allocation based on historic 1990 CO2 emissions. Maryland and Rhode Island would benefit most from an allocation based on 2002 fossil fuel consumption.

Pennsylvania, with its substantial coal generation growth since 1990, would benefit most from an allocation based on 2002 CO_2 emissions (see Exhibit 4.)

These allocation outcomes underscore the differences in fuel consumption, emissions and generation portfolios among the nine RGGI states and states observing the RGGI process. The results suggest that finding common ground among these states on an allocation method may be difficult, without considering prior state commitments to specific greenhouse gas reduction programs.

At the individual company level, the use of a fuel-neutral EPS approach would create market penalties (liabilities) and rewards (windfalls) based on each firm's CO_2 emission intensity, measured in pounds of CO_2 per megawatt-hour of generation. Firms providing power at levels below an emission rate target would be able to command a market premium, while reduced power prices would penalize those attempting to sell power at emission rates above the target. Appendices A and B provide illustrative estimates of the economic benefits that an EPS could confer upon major power producers in the 9- and 12-state regions.

Cap-and-Trade

Both the national acid rain control program for sulfur dioxide (SO_2) and the Northeast Ozone Transport Commission's Nitrogen Oxides trading rule for seasonal NO_x control have successfully applied the cap-and-trade model. These cap-and-trade models allocate emission allowances for each year to affected sources (usually based upon historical fuel use) that aggregate to a selected emission tonnage cap.

The cap-and-trade approach places the full compliance burden onto fossil fuel-fired EGUs and provides them flexibility to develop and implement their own compliance strategies. Since sources must retire the same number of allowances as their annual emissions, the program's emission limits are also easy to enforce.

Unlike controls for SO_2 and NO_x, retrofit CO_2 emission control technologies do not currently exist. Affected EGUs would need to comply through a combination of trading of CO_2 emission credits, shifting generation mix to lower carbon fuels, or capping fossil fuel generation output.

Generators would incorporate carbon emission allowance trading values into their unit dispatching costs, influencing generation output and mix. Adding carbon costs into regional dispatching decisions would place a premium on fossil-fired generation from outside the regulated region and on non-carbon based generation inside the region. In a northeastern regional CO_2 reduction program, carbon penalties would encourage additional power imports from Canada, the Midwest and the South, thereby displacing some local generation. “Leakage” – increased generation and emissions from states outside the region - would partially offset emissions reductions from local displaced power. The findings reported in this study do not take into account any “leakage” to surrounding areas. We report costs and other findings on the basis of compliance solely within the Northeast.

Emissions Portfolio Standard

The renewable portfolio standards adopted by several states to promote renewable energy generation serve as a model for an emissions portfolio standard (EPS). Under an EPS approach, power providers (not generators) have the direct compliance burden. Retail power providers must purchase power that, on average, can meet an average CO_2 emission rate per MWh output. Dividing the carbon emission target by estimated regional power sales calculates the emissions rate target. Suppliers and power pools must report their CO_2 emissions from each power purchase to their buyers.

The principal administrative advantage of an EPS is that it avoids the need to issue and to account for emission allowances, the “currency” of any market-based cap-and-trade system. States enforce compliance through certification by retail electric providers of a weighted average CO_2 per MWh delivered to customers. Regulators set the EPS at a level consistent with meeting a given tonnage reduction of overall CO_2 emissions in a state or region, based on historic and projected emissions and generation data.

Under an EPS, suppliers of nuclear and renewable energy would gain a premium value for having zero-carbon generation that can be applied to offset higher carbon-emitting generation (e.g. coal). The emissions portfolio approach thus effectively increases the environmental penalty and shifts a greater compliance burden onto coal-fired powerplants. In the Northeast region, coal-based states such as Pennsylvania, Maryland and Delaware would have the most to lose by adopting an emissions portfolio standard keyed to an overall regional reduction target.

While portfolio standards are workable for renewable energy supplies - where sources are easily categorized - the portfolio standard approach cannot be easily applied when power suppliers have large and diverse generation portfolios with a continually changing mix of emissions. Several Northeastern states[1] currently require power suppliers to disclose air emission rate estimates for the power provided to their consumers. However, these emission estimates often use historic regional averages, and, in other cases, may be overly conservative.

Creating an enforceable emission portfolio standard would require current and accurate emissions data. This poses a significant compliance challenge since generation diversity makes emissions tracking very difficult, especially for economy power purchases off the grid. Most power providers would be unable to calculate the associated carbon emissions for a given purchase until long after the completed power sale. Developing and implementing compliance plans would pose substantial burdens on even the largest electric providers, given their inability to track emissions or to gain direct control over power suppliers' emissions.

EPS advocates maintain that by placing the compliance burden onto power providers, emission portfolio standards can reduce the "leakage" problem since all power purchases regardless of geographic origin would be subject to the same emission standard, thus effectively "leveling the playing field" between in- and out-of-state suppliers. However, an emission portfolio standard also could lead to <u>increased</u> power exports from coal-based generation within the affected region to nearby states. Low-cost generators unable to sell all of their output in traditional markets could seek new markets outside the region affected by the EPS. Similarly, producers of low-emitting power outside the region could seek to increase their sales to the RGGI region. This could induce increased generation from conventional generation outside the RGGI region.

With the much higher dependence on coal-based generation in states to the west and south of the RGGI region, an EPS also could discriminate against interstate power sales. The expansion of the PJM system to include EGUs in coal-dominated states, such as West Virginia, Ohio and Kentucky, squarely raises this issue.

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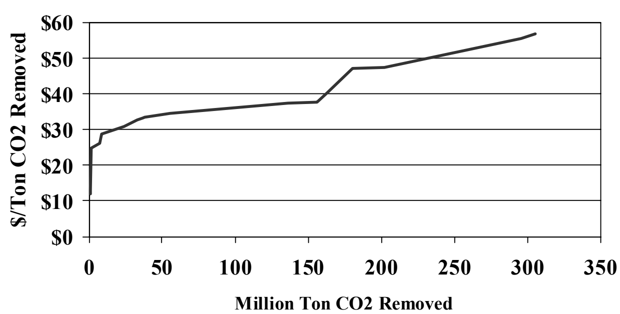
[1] States with environmental disclosure requirements include Connecticut, Delaware, Maine, Maryland, New Jersey and New York.

Setting the Emissions Target

Compliance costs for carbon control are heavily dependent upon the design of emission trading provisions, the absolute emission reduction target, and the mix of generation within an affected area. Emissions trading and offset provisions can have a dramatic impact on compliance costs. If a RGGI emissions control program allowed full access to carbon sink credits and domestic and international carbon offset markets, marginal compliance costs could be reduced significantly.

For example, most forestry carbon sink projects have project costs between \$2-5/ton CO2 capture. International carbon credits in Europe are trading in the range of \$10-15/ton CO2. These costs are well below direct Northeastern supply side reductions from the EGU sector ranging from an estimated \$20 to \$60/ton CO2 reduced,[2] depending upon the magnitude of the CO2 removal requirement.

Exhibit 1
Northeastern Direct CO2 Reduction Costs



As shown in Exhibit 1, direct supply side reduction compliance costs for the EGU sector rise significantly as the emission reduction requirement is raised, forcing increasingly more expensive emission reduction alternatives (e.g., increasing biomass co-firing, adding new wind capacity, and switching to lower carbon fuels such as natural gas.) Northeastern compliance costs in an expanded

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[2] _Setting a Northeastern CO2 Emissions Cap on the Electric Power Industry—Compliance Options, Costs and Market Impacts_ (EVA, August 2003). This study, available in the stakeholder comment section of the RGGI website (www.rggi.org), examined the direct carbon dioxide reduction costs for 11 Northeastern states in New England, New York, Pennsylvania, New Jersey, Maryland and Delaware.

12-state RGGI region could exceed $3 billion per year if the CO2 target were set at a level 20% below 1990 levels without sink credits or access to allowance markets. Full access to carbon sink credits could achieve the same level of reduction at an annual cost of $429 million.

The affected geographic area is the third major factor driving compliance costs. If the carbon control region excludes the coal-based states of Pennsylvania and Maryland, overall program compliance costs could drop as much as 65% to 80%. This is because Pennsylvania and Maryland would bear most of the costs of a 12-state expansion of the RGGI control region, reflecting their higher dependence upon coal-based generation and emissions growth since 1990.

Exhibit 2 summarizes compliance costs for a range of emission control targets for alternative 9- and 12-state geographic configurations. The cost estimates in this table are based upon the methodology developed in the author's above-cited study of Northeastern carbon reduction costs. Costs for meeting reductions through carbon sink offsets are assumed at a level of $5 per ton of CO2 reduced.

Exhibit 2. Alternative Carbon Emission Limitations and Costs

Limit	EPS Rate (Lbs. CO2/MWh) @2002 Generation Level		Compliance Cost (Million $/Year) @2002 Generation Level	
	12 State	9 State	12 State	9 State
			w/o carbon sink credits, 2002 MWh	
Current	1,077	870		
1990 Level	975	872	$ 1,019	$ (9)
10% Below	878	785	$ 2,167	$ 431
20% Below	780	698	$ 3,226	$ 1,061
	@2013 Generation Level		w/o carbon sink credits, 2013 MWh	
Current	897	691		
1990 Level	813	692	$ 1,129	
10% Below	731	623	$ 2,096	
20% Below	650	554	$ 3,243	
	Emissions Cap - Tons CO2/yr		w/carbon sink credits, 2002 MWh	
2002 Level	310,825,435	141,854,120		
1990 Level	281,405,000	142,148,000	$ 147	$ -
10% Below	253,264,500	127,933,200	$ 288	$ 70
20% Below	225,124,000	113,718,400	$ 429	$ 141

Exhibit 3 shows costs by state to reduce RGGI power plant emissions to 10% below 1990 levels, based on alternative 9- and 12-state coverage, with and without potential credits for carbon sinks. As above, we assume a $5 per ton of CO2 cost for carbon sinks in this example, and allow affected sources to use sinks to offset their entire emission liability. Exhibit 3 also compares 1990 and 2002 coal consumption by state.

Exhibit 3. Distribution of Costs by State to Reduce EGU CO2 to 10% Below 1990 Levels, Alternative 9-and 12-State Coverage, 2002 Generation Basis

State	1990 Coal Burn (Mil. Tons)	2002 Coal Burn (Mil. Tons)	9-States With Sinks ($ Mil.)	12-States W/o Sinks ($ Mil.)
CT	0.96	1.38	($12.2)	($146.3)
DC				$8.0
DE	2.06	1.60	$23.9	$169.8
MA	4.20	4.61	$42.6	$249.0
MD	8.95	11.16		$404.1
ME		0.40	$9.6	$34.3
NH	1.15	1.53	($7.7)	($86.7)
NJ	2.74	4.07	($12.4)	($198.9)
NY	9.99	8.87	$33.0	$6.5
PA	41.46	51.33		$1,801.4
RI			$2.0	$3.3
VT			($9.2)	($77.9)
Total	**71.50**	**84.95**	**$69.6**	**$2,166.6**

(Note: The negative costs above reflect that four states have a net surplus of carbon dioxide credits that could be sold at their market value to other state power providers)

Emission Allocation Formulae

The distribution of emission reductions and compliance cost burdens among states and among sources is highly dependent upon the emission allowance allocation formula or emission portfolio standard selected. Exhibit 4 displays a range of different allocation results to return RGGI emissions to 1990 levels.

Formulae proportioning allowances using historic carbon emissions provide the greatest allocation to coal units because of their higher carbon fuel content. Oil units also benefit the most under this allocation approach. In this analysis, no allowances are awarded to non-emitting sources (nuclear, renewable, etc.), leaving allowances only to fossil fuel sources. This allocation technique provides the most uniform percent reduction requirement across states.

Proportioning allowances using historic fossil fuel consumption also awards allowances to only fossil fuel burning sources and provides no direct credit for non-carbon based generation alternatives. However, since gas, oil and coal are given allocations based upon their heat content and not carbon content, this alternative effectively subsidizes lower carbon fuels such as natural gas.

Emission portfolio standards and formulae allocating allowances based upon net generation include both fossil fuel and non-carbon emitting generation. Under these approaches, non-emitting generation sources such as nuclear, hydroelectric and renewables receive a direct price premium or subsidy (not a cost) that increases with tighter carbon limitations. Fossil-fuel generators with more efficient heat rates are penalized less with an output-based standard. This approach would significantly increase compliance costs on coal-intensive EGUs and states (Delaware, Maryland and Pennsylvania) while lowering them in nuclear- and renewable-intensive areas (e.g., Connecticut, Maine and Vermont).

Exhibit 4. Alternative Emission Allocation Formulae for Achieving 1990 CO2 Emissions Level (Tons per Year)

Baseline	2002 CO2 Emissions Tons	% Total	Historical 1990 CO2 Emissions Level (Tons) TPY	%	Estimated 2002 CO2 Emissions Level (Tons) TPY	%	2002 Fossil Fuel Consumption (MMBtu) TPY	%	Emissions Portfolio Standard (#/MWh) TPY	%
CT	9,803,074	3.2%	12,514,000	4.4%	8,875,187	3.2%	10,605,645	3.8%	**15,210,086**	**5.4%**
DC	327,480	0.1%	**439,000**	**0.2%**	296,483	0.1%	340,856	0.1%	127,774	0.0%
DE	7,097,216	2.3%	**8,168,000**	**2.9%**	6,425,446	2.3%	6,512,136	2.3%	2,874,813	1.0%
MA	24,618,162	7.9%	**27,445,000**	**9.8%**	22,287,989	7.9%	24,836,535	8.8%	20,003,967	7.1%
MD	31,748,579	10.2%	28,377,000	10.1%	28,743,493	10.2%	**31,704,969**	**11.3%**	23,347,524	8.3%
ME	10,449,658	3.4%	1,995,000	0.7%	9,460,571	3.4%	9,450,928	3.4%	**10,597,728**	**3.8%**
NH	4,955,849	1.6%	5,761,000	2.0%	4,486,765	1.6%	5,906,688	2.1%	**8,064,455**	**2.9%**
NJ	21,089,319	6.8%	12,571,000	4.5%	19,093,160	6.8%	15,327,960	5.4%	**29,304,772**	**10.4%**
NY	60,766,437	19.6%	**72,973,000**	**25.9%**	55,014,736	19.6%	64,389,313	22.9%	67,325,439	23.9%
PA	136,895,257	44.0%	110,441,000	39.2%	**123,937,765**	**44.0%**	108,648,319	38.6%	98,930,325	35.2%
RI	3,064,401	1.0%	525,000	0.2%	2,774,347	1.0%	**3,402,591**	**1.2%**	3,308,858	1.2%
VT	10,004	0.0%	196,000	0.1%	9,057	0.0%	279,061	0.1%	**2,309,258**	**0.8%**
Total	310,825,435	100%	281,405,000	100%	281,405,000	100%	281,405,000	100%	281,405,000	100%
9 State	141,854,120	45.6%	142,148,000	50.5%	128,427,259	45.6%	140,710,856	50.0%	158,999,377	56.5%
MD-PA-DC	168,971,315	54.4%	139,257,000	49.5%	152,977,741	54.4%	140,694,144	50.0%	122,405,623	43.5%
Data Source used for Allocation:			USDOE: 1990 Electric Power *Power Annual Table 43*		2002 EIA Form 906 Database Station fossil fuel consumption Multiplied by DOE CO2 Factors		EPA 2002 CEMS Data (June 2003)- Fuel Heat input		EIA Form 906 Data for 2002 Reporting station net generation	

Note: Bold data denote largest emission allocation by stat

As shown in Exhibit 4, Maryland and Pennsylvania would lose nearly 18 million tons of CO2 allowances under an EPS allowance allocation based on total generation versus using a fuel consumption-based formula. Maryland and Pennsylvania would stand to lose 30 million tons of allowances under these approaches versus a carbon emission-based formula.

Finally, the highlighted data in Figure 4 show the emission allocation most favorable (least costly) to each of the 12 states. Five states – Connecticut, Maine, New Hampshire, New Jersey and Vermont – would benefit most from a fuel-neutral EPS based on total generation. New York, Massachusetts, Delaware and DC would gain most from an allocation based on historic 1990 CO2 emissions. Maryland and Rhode Island would benefit from an allocation based on 2002 fossil fuel consumption. Pennsylvania, with its substantial coal generation growth since 1990, would benefit most from an allocation based on 2002 CO2 emissions.

These differences in allocation outcomes underscore the differences in fuel consumption, emissions and generation portfolios among the nine RGGI states and states observing the RGGI process. The results suggest that finding common ground on an allocation method even among the nine RGGI states may be difficult, without considering prior state commitments to greenhouse gas reduction programs.

Estimated EPS Windfalls and Liabilities

In the context of an environmental portfolio standard, firms with large portfolios of nuclear or other non-emitting assets would realize a market windfall in the form of a premium price for their power. Firms primarily dependent on coal, oil or other carbon-intensive generation would incur market penalties for their output.

To estimate potential company-specific carbon emission windfalls and liabilities, we collected 2002 generation data from EIA Form 906 for all power generation located in the 12-state northeastern region, comprised of the six New England states (CT, MA, ME, NH, RI, VT) and six Mid-Atlantic states (DC, DE, MD, NJ, NY, PA). This reported generation includes electric utility, independent power producers, and industrial power generators, totaling 576 Terawatt-Hours (TWh). We calculated carbon dioxide emissions at 310 million tons of CO2, based upon reported fuel consumption and U.S. DOE CO2 emission factors. For renewable biomass, MSW and LFG generation options, we assumed CO2 emissions to be net zero since we considered the carbon emissions to be recycled.

In the next step, we aggregated carbon emissions and generation by power generator, based upon plant ownership interests. Carbon windfalls and liabilities were calculated at a company level for achieving an emissions portfolio standard using the 2002 generation baseline. Since emission rates varied significantly by state, substantial differences exist in the emissions portfolio standard depending upon the participating states. Based upon potential carbon limitations ranging from 2002 CO2 emissions stabilization to a level 20 percent below 1990 emissions, the carbon reduction requirements (or credits in cases of hydro, nuclear and renewable generation) were calculated for each scenario by plant and by company.

The final step multiplied the carbon reduction credit by marginal carbon reduction cost. This cost varied by carbon limitation and was developed from EVA's study, <u>*Setting the Northeastern CO2 Emissions Cap on the Electric Power Industry—Compliance Options, Cost and Market Impacts*</u> (August 2003). These costs are shown with and without credits for carbon sinks (assumed at $5/ton CO2) and emissions trading.

Appendix A provides a summary listing of the "top-10" companies with potential carbon windfalls for the 12-state New England/Mid-Atlantic region, and Appendix B provides a similar analysis for the 9-state RGGI region. Detailed findings for all power generators in the 9- and 12-state regions are contained in the spreadsheet file, "Summary NE Generation Statistics.xls," available from the author upon request.

Based on these preliminary calculations, some nuclear-intensive companies participating in the RGGI process could stand to gain as much as a half-billion dollars of annual revenues from the adoption of an EPS. These preliminary results are illustrative, since individual companies have specific market demand and generation supply options that could indicate substantially different outcomes.

Conclusion

Carbon control policies can significantly increase power production costs that likely would be passed onto regional consumers in higher power bills. Compliance costs and the distribution of emission reduction burdens vary significantly based upon the limits adopted and the method used to allocate emission credits.

Maryland, Pennsylvania and Delaware - with their high degree of dependence upon coal-based generation – potentially have the largest reduction requirements of the 12 Northeastern states. These reductions would decline relative to an emissions portfolio approach using emission allocations based upon historic carbon emissions. Full access to carbon sinks and offsets would dramatically reduce compliance costs for any of the targets evaluated in this report.

Additional Information

Copies of supporting spreadsheets and the author's previous analysis of Northeastern CO2 control costs are available on request from hewson@evainc.com.

APPENDIX A

POTENTIAL CARBON WINDFALLS FOR TOP-10 POWER SUPPLIERS BASED ON EMISSION PORTFOLIO STANDARDS IN A 12-STATE NORTHEASTERN REGION (Includes DC, MD and PA)

(In millions of dollars/yr and $ per MWh)

	1990 Stabilization	**1990 Stabilization**	**1990 –20%**	**1990 -20%**
Top-10 Windfalls	**With sinks and trading**	**Without sinks and trading**	**With sinks and trading**	**Without sinks and trading**
Exelon	**$99/$1.58 MWh**	**$683/$10.96 MWh**	**$68/$1.10 MWh**	**$514/$8.25 MWh**
Entergy	**$79/$2.44 MWh**	**$545/$16.89 MWh**	**$62/$1.95 MWh**	**$474/$14.69 MWh**
PSNY	**$47/$1.89 MWh**	**$322/$13.10 MWh**	**$35/$1.40 MWh**	**$260/$10.57 MWh**
Dominion	**$36/$2.40 MWh**	**$251/$16.60 MWh**	**$29/$1.91 MWh**	**$217/$14.38 MWh**
PSEG	**$28/$0.59 MWh**	**$196/$4.11 MWh**	**$5/$0.11 MWh**	**$38/$0.79 MWh**
FPL	**$23/$1.83 MWh**	**$162/$12.69 MWh**	**$17/$1.35 MWh**	**$129/$10.13 MWh**
Constellation	**$11/$0.24 MWh**	**$78/$1.69 MWh**	**-$11/$0.24 MWh**	**-$85/$1.84 MWh**
Covanta	**$6/$2.40 MWh**	**$40/$16.62 MWh**	**$5/$1.91 MWh**	**$35/$14.40 MWh**
Long Is. PA	**$4/$2.44 MWh**	**$25/$16.89 MWh**	**$3/$1.95 MWh**	**$22/$14.69 MWh**
MA Munis	**$3/$2.44 MWh**	**$18/$16.89 MWh**	**$2/$1.95 MWh**	**$16/$14.69 MWh**

APPENDIX B

POTENTIAL CARBON WINDFALLS FOR TOP-10 MAJOR POWER SUPPLIERS BASED ON EMISSION PORTFOLIO STANDARDS IN A 9-STATE NORTHEASTERN REGION (Excludes DC, MD and PA)

(In millions of dollars/yr and $ per MWh)

	1990 Stabilization	**1990 Stabilization**	**1990 –20%**	**1990 -20%**
Top-10 Windfalls	**With sinks and trading**	**Without sinks and trading**	**With sinks and trading**	**Without sinks and trading**
Entergy	**$70/$2.18 MWh**	**$436/$13.51 MWh**	**$56/$1.74 MWh**	**$424/$13.15 MWh**
PSNY	**$40/$1.63 MWh**	**$249/$10.12 MWh**	**$29/$1.20 MWh**	**$222/$9.02 MWh**
Constellation	**$34/$2.18MWh**	**$210/$13.51 MWh**	**$27/$1.74 MWh**	**$205/$13.15 MWh**
Dominion	**$33/$2.18MWh**	**$201/$13.51 MWh**	**$26/$1.74 MWh**	**$196/$13.15 MWh**
Exelon	**$27/$1.70MWh**	**$170/$10.57 MWh**	**$20/$1.27 MWh**	**$154/$9.57 MWh**
FPL	**$20/$1.57 MWh**	**$125/$9.75 MWh**	**$15/$1.14 MWh**	**$109/$8.58 MWh**
PSEG	**$9/$0.28 MWh**	**$58/$1.75 MWh**	**-$5/($0.15) MWh**	**-$38/($1.16) MWh**
Wheelabrator	**$4/$2.18 MWh**	**$27/$13.51 MWh**	**$4/$1.74 MWh**	**$27/$13.15 MWh**
Covanta	**$4/$2.13 MWh**	**$25/$13.20 MWh**	**$3/$1.69 MWh**	**$24/$12.78 MWh**
Long Is. PA	**$3/$2.18 MWh**	**$20/$13.51 MWh**	**$3/$1.74 MWh**	**$20/$13.15 MWh**