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Massachusetts Renewable Portfolio Standard

Cost Analysis Report

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1. OVERVIEW AND KEY RESULTS

1.1. Overview

The Massachusetts Electric Utility Restructuring Act ("the Act") requires the Massachusetts Division of Energy Resources (DOER) to develop and implement a renewable energy portfolio standard ("RPS") for the state of Massachusetts. To complement the process of developing the design details of the RPS, an analysis of the potential costs and impacts of the RPS was developed. The basic approach and design of this cost and impact analysis is detailed in *White Paper #9: Evaluation Methodology.*[1] The results of the actual analysis are presented in this paper. Overall, the analysis was developed with two basic goals in mind:

1. ***Accountability:*** It is generally good practice for state agencies to evaluate the potential costs and impacts of the policies that they develop and implement.
2. ***Policy Scenario Analysis:*** A policy-analysis tool that can evaluate the costs and impacts of different possible approaches to structuring and applying the RPS may help inform the DOER's RPS design decisions.

Specifically, we focused on these key questions under high, low and base case scenarios of cost-drivers:

- What range of impacts can be expected to result from the minimum new renewables requirements in the Act, in terms of incremental renewable energy generated, rate impacts to retail electricity customers in Massachusetts, and emissions displaced?
- What is the potential impact of a requirement to maintain the baseline fraction of renewable resources historically included in the supply to Massachusetts's customers prior to the Act?

From these base-case and scenario analyses, several implications can be drawn related to important RPS policy design decisions. In addition, we also performed sensitivity analysis to inform the DOER on three specific design issues:

- What is the potential value of providing regulatory certainty to generators that the new renewables requirements in the Act will not be abruptly terminated?
- What are the potential impacts of alternative definitions of biomass eligibility on the new renewables requirements in the Act?
- What are the cost and impact implications of applying the RPS to each of a retail electricity supplier's products individually, versus to the supplier's aggregate sales to end-use customers in Massachusetts?

Finally, we also discuss the potential impact of system benefit charge funds targeted at accelerating the market presence of renewable resources.

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[1] Wiser, R., D. Smith and K. Cory. 2000. Massachusetts Renewables Portfolio Standard White Paper #9: Evaluation Methodology. Prepared for the Massachusetts Division of Energy Resources. 20 April.

The analysis itself is structured to quantitatively estimate the costs and impacts of the Massachusetts RPS under a “base case” outlook, and to test the results under alternative scenarios composed of sets of assumptions for key variables. We focused on the costs and impacts that will be experienced by Massachusetts electricity customers for four “snapshot” years: 2003, 2006, 2009 and 2012 to present a reasonable picture of how developments, costs and impacts unfold over time.

We have estimated the costs of the RPS program as the sum of three components:

- ***Incremental Renewable Generation Costs:*** The incremental cost of renewable energy or renewable energy credits needed to comply with the RPS. This cost will depend primarily on the difference between the “all-in” cost of power from renewable generating sources and the marginal cost of power from non-renewable sources.
- ***Transactions Costs:*** The wholesale (generator and/or broker) and retail (retail supplier) transactions costs related to the personnel and resources needed to buy and sell renewable energy to comply with the RPS.
- ***Administration Costs***: The incremental start-up and ongoing costs of administering the RPS, from both supplier and administrator perspectives.

In addition to estimates of ratepayer costs, the analysis also provides a more limited quantitative and qualitative assessment of other possible impacts, including the amounts of renewable resources developed as a result of the Massachusetts RPS and regional air emissions displaced by the renewable generation.

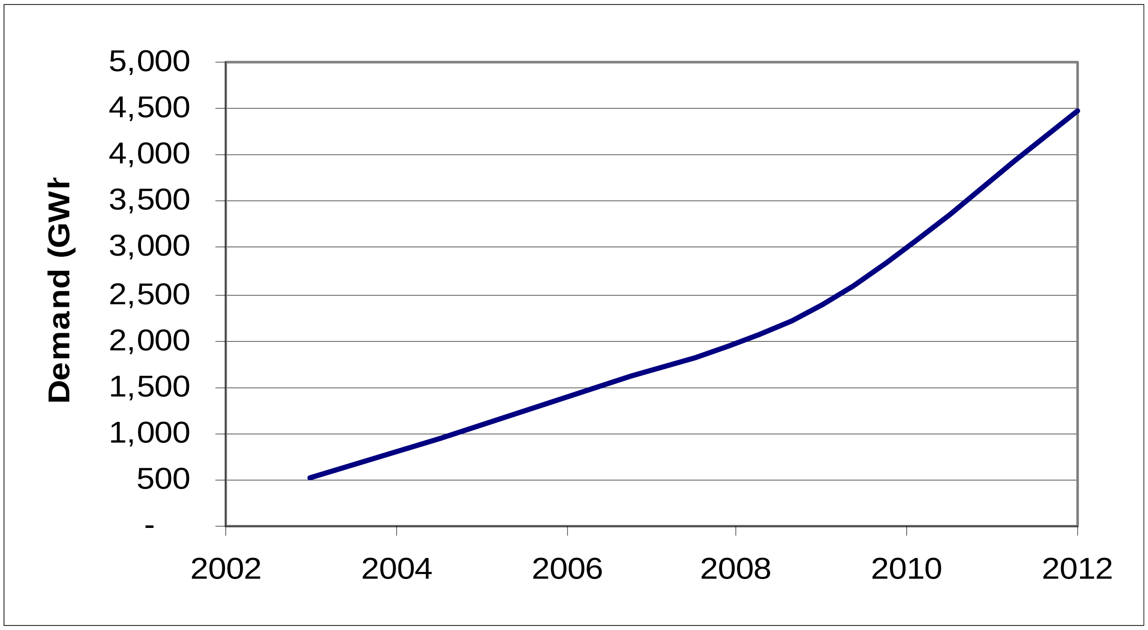
The highlights of our analysis and findings are summarized below in Sections 1.2 – 1.9. Chapters 2 - 4 provide additional detail on the analysis approach, assumptions, and results. Finally, a number of Appendices are included that provide additional detail on model structure and input assumptions.

1.2. Key Results

1.2.1. Quantities of Renewable Generation Developed

The Act prescribes that specific (and increasing) annual fractions of retail electricity sales in Massachusetts be derived from qualifying renewable generation sources. The RPS requirement in terms of GWh of needed renewable energy supply will therefore vary in proportion to electricity consumption in the Commonwealth, and will be expressed in terms of annual *energy production*. Figure 1 presents the estimated Massachusetts RPS requirements for new renewable energy generation (in GWh per year) over time.

Figure 1: Quantity of Renewable Energy Developed Due to the MA RPS



The amounts of new renewable *generating capacity* needed to produce the required amounts of energy will depend on the types of resources that are developed. For perspective, Table 1 shows the range of capacity that would be required to meet the projected requirements if the requirement were met entirely with wind (with an assumed annual capacity factor of 27 percent), or entirely with baseload sources such as landfill methane or biomass generation operating at full availability (assuming an annual capacity factor of 85 percent).

Table 1: Equivalent Capacity to Meet the MA RPS, if Only One Technology is Used

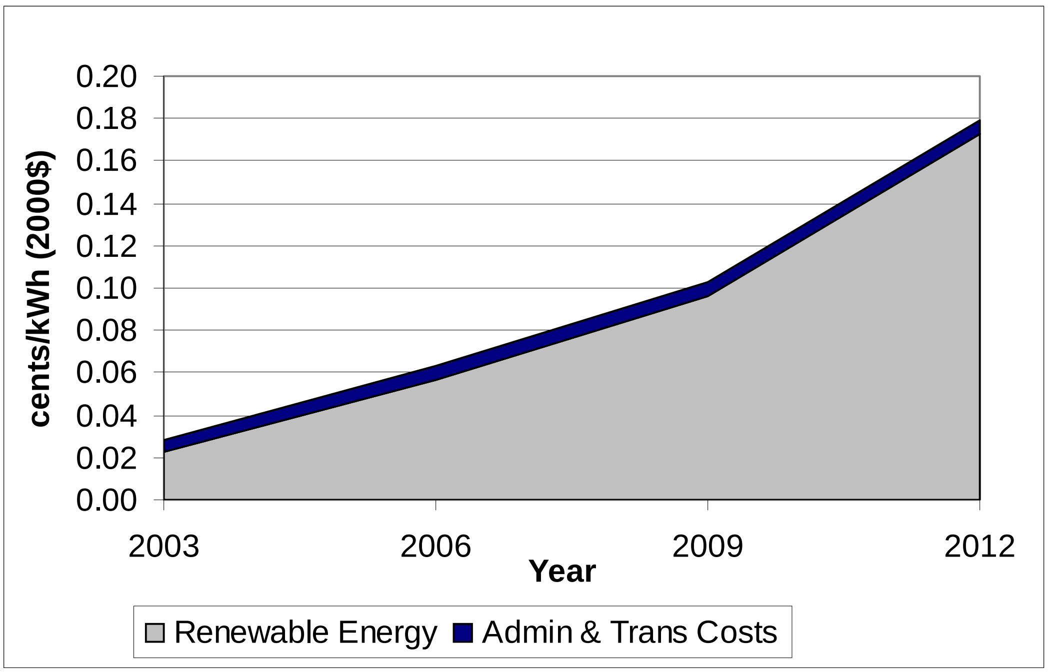
MW	2003	2006	2009	2012
Wind (27% CF)	219	589	1,009	1,889
Baseload (85% CF)	70	187	320	600

1.2.2. Rate Impacts of the New Renewable Energy Requirements

The estimated costs of the RPS program consist of incremental renewable generation costs as well as transaction and administration costs. This analysis assumes that these costs will ultimately be passed through to Massachusetts retail customers, primarily through the price of generation service (whether from competitive suppliers, standard offer service providers, or default service providers).

Figure 2 shows the estimated impact of the RPS program on Massachusetts retail electricity bills, in cents per kWh (year 2000 dollars), for each of the sample years, under our base-case input assumptions. Also illustrated by shading are the relative fractions that are attributable to incremental renewable generation costs versus administrative/transaction costs. For the purpose of this base-case analysis, we assume that Massachusetts renewable energy credits are used to verify RPS compliance (See Figure 5 for the rate impacts of the various accounting approaches.)

Figure 2: New RPS Requirement - REC Rate Impact (base case)



Putting these figures in perspective, if the average total bundled[2] retail rate in Massachusetts holds at approximately 9.0¢ per kWh (in 2000$), the base case rate impacts would reflect a roughly 0.3 percent increase in the average retail rate in 2003, increasing to about 2.0 percent in 2012.

As is evidenced by this analysis, the total costs of the RPS are expected to rise over time as the RPS requirement itself increases. While technology advance and scale economies are expected to drive the costs of renewables down over time, the effect of increasing demand for renewables works to counter these advances as the lower-cost renewable energy sites and resources are depleted. Incremental renewable generation costs are expected to dwarf the administration and

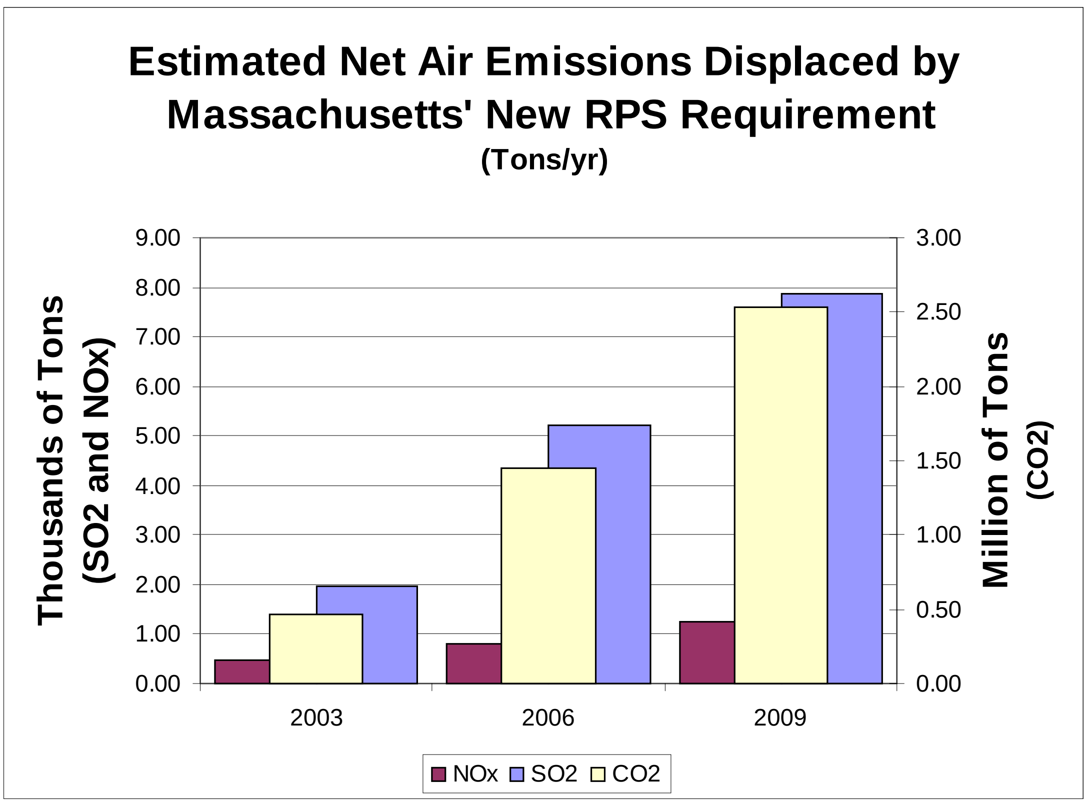
[2] The bundled rate includes all services formerly provided by the monopoly utility, and today provided by the local distribution company (transmission, distribution, transition, and systems benefit charges) and the generation service supplier.

transaction costs related to RPS compliance procedures. For the four years analyzed, administration and transactions costs combine to constitute an average of about 5 percent of the total costs to retail customers of the RPS obligations.

1.2.3. Air Emissions Displaced by Renewables

Generation from new renewable resources should lead to reduced output at fossil-fired generating plants in New England, and therefore to reduced air emissions from those plants. To estimate the air emissions that could be displaced by new renewable generating sources, we used a regional dispatch simulation of the New England electricity market. This analysis estimated the regional emissions of SO_2, NO_x, and CO_2 that could be displaced by new renewables associated with the Massachusetts RPS, along with the emissions (if any) associated with the new renewables. Figure 3 presents the estimated net reduction in air emissions for each snapshot year, assuming that these emissions reductions are permanent.

Figure 3: Net Emissions Displaced by Massachusetts' New RPS Requirement



It is important to note, however, that SO_2 and NO_x are presently regulated under "cap and trade" programs in which the total allowed emissions are fixed on a national and regional basis, respectively. In addition, there is potential for the development of an international market in CO_2 offsets. We therefore anticipate that some portion of the emissions displacement estimated here may ultimately be eroded, to the extent that SO_2 allowances, NO_x emission reduction credits or

CO_2 offsets are created and sold to parties that increase their emissions accordingly (thereby reducing the need for other control measures). DOER's approach is that the capped emission levels are not necessarily affected by the introduction of the RPS. However, to the extent that a generator taps additional revenue streams by selling allowances, ERCs or offsets, the revenue required from sale of energy and attributes is reduced accordingly. Therefore, to the extent that emission reductions fall short of those predicted, we would expect a corresponding decrease in the cost of renewables to retail suppliers, the compliance costs of those suppliers, and ultimately to the cost impact of the RPS to electricity customers in the Commonwealth.

1.2.4. Sensitivities/Bounding Analysis

This analysis is based on a range of assumptions about the cost and depth of the renewable energy supply market and the renewable market demand; the actual outcomes for many of these parameters will vary. Of particular importance is the fact that RPS-driven demand for new renewables will increase substantially over the next decade, putting upward pressure on the supply curve at the same time that technology improvements, additional operating experience, and improved scale economies can be expected to lower the cost of power from some of the key renewable technologies.

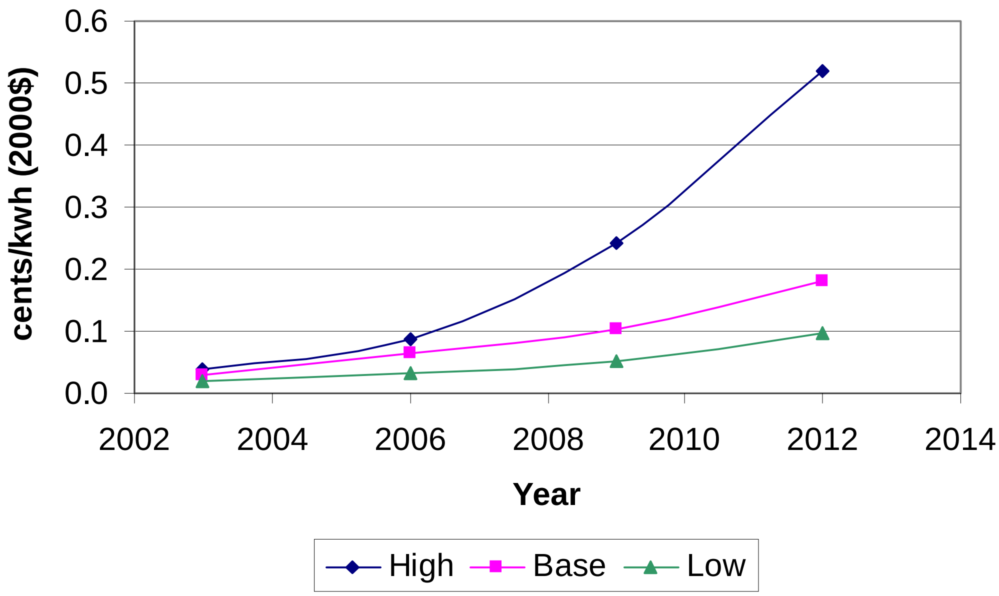
The cost results presented above reflect a base case outlook for each of the major input assumptions, details of which may be found in subsequent chapters and the appendices of this paper. To bound the potential variance in outcomes (particularly impacts on Massachusetts's electricity rates), this analysis also explored high and low cost case sensitivities. As explained further in Chapter 2, applying specific changes to some of the key input assumptions allowed us to develop the high and low compliance cost cases. Our objective was not to assume a "worst case" outcome for every parameter, but to test plausible combinations of outcomes that tend to produce relatively high or low compliance costs. The primary changes were to vary:

- available generation quantities and costs of power from each renewable technology;
- demand for renewables driven by both market and regulatory factors;
- the impact of systems benefit charge fund expenditures upon the renewable supply curve; and
- the role of the Federal Production Tax Credit for wind.

Figure 4 displays the potential range of Massachusetts electricity rate outcomes bounding the expected costs of the Massachusetts RPS requirement for new renewables that result from this analysis. The asymmetrical appearance of the high and low cases can be explained by the shape of the supply curves and the point at which the demand forecast intersects with these curves. In particular, while the difference between high, base and low cases is small in the early years due to a shallow slope to the supply curve, the supply and demand intersect at a steeper part of the supply curve in the high case than in low case in later years. This reflects the possibility that eligible resources may be scarce in combination with higher demand, so that higher-cost renewables will called upon in later years under the high demand case.

Section 2.11 identifies and discusses additional factors (beyond the high and low compliance cost cases examined in Section 2.10) that may affect the overall rate impact of the new RPS requirement.

Figure 4: New RPS Requirement - Range of Rate Impacts



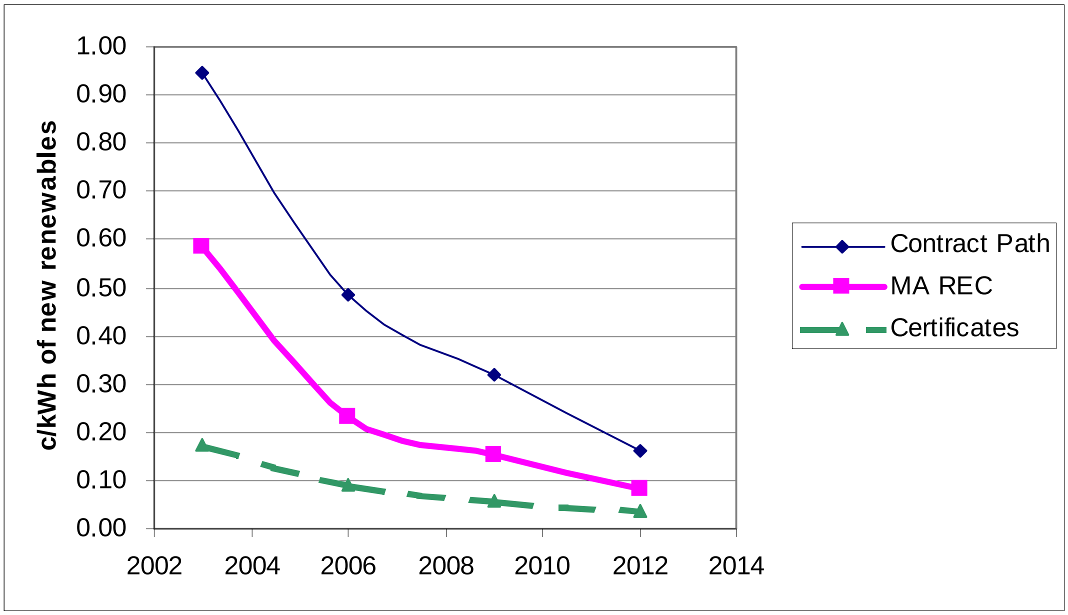
1.2.5. Administration and Transaction Costs

Also of particular importance are the administration and transaction costs associated with meeting and administering an RPS, costs which are likely to vary depending on the accounting and verification system used. The base-case analysis presented in this paper assumes that a Massachusetts Renewable Energy Credit approach is used. As detailed in a later chapter and accompanying Appendix A, a lower incremental-cost possibility would be the use of a "full certificates" program supporting all generation attribute requirements[3] on a region-wide basis. A higher-cost possibility would be to rely on restricted unbundling, a system that tracks the title to renewable attributes via contract path of energy transactions.

Figure 5 summarizes the estimated relative cost (per kWh of new renewables) of these three accounting and verification systems over time. Though the variation in cost is substantial in percentage terms, it should be noted that in all cases the incremental cost of renewable generation is expected to dwarf administration and transaction costs.

[3] Including information disclosure and emission performance standards as well as various state RPS requirements.

Figure 5: MA RPS Administration and Transaction Costs

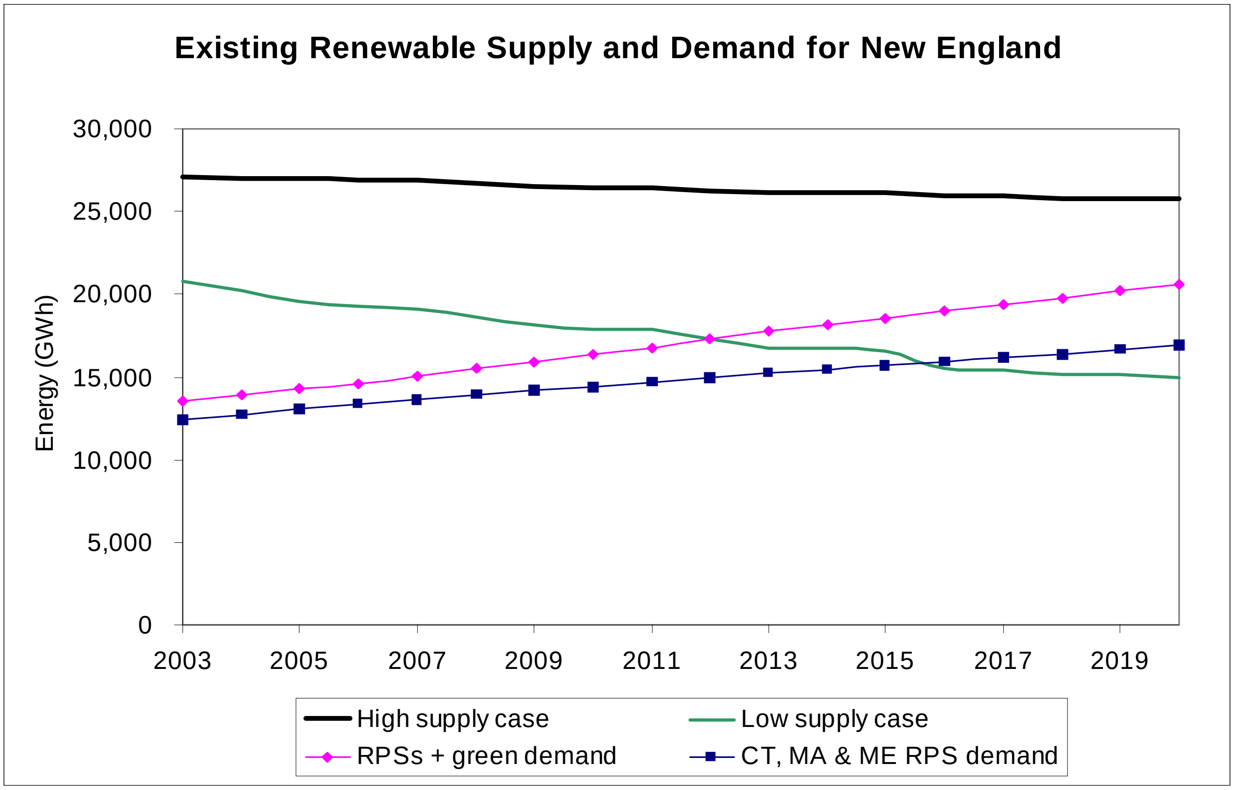


1.2.6. Efficacy of Requirement for Existing Renewables

We examined the potential supply and demand for existing renewables, to inform DOER's determination as to whether implementing an existing renewables requirement at this time would be meaningful. First, we estimated the demand for existing renewables from existing state RPS programs in Maine, Connecticut and Massachusetts, and then we estimated consumer-driven green demand. The supply of existing renewables will depend on a range of factors including future wholesale power prices, the going-forward costs at existing renewable plants, and the magnitude of a market premium (if any) for existing renewables. We constructed high and low supply scenarios for existing renewables, based on alternative assumptions regarding the rate of retirement of existing renewable plants in New England, and potential renewable imports from neighboring regions. Figure 6 illustrates the estimated regional supply/demand balance for existing renewables over time for the high and low supply cases.

Based on our analysis, the supply of existing renewables exceeds the demand throughout the horizon in the high supply case, and for about ten years in the low supply case. Furthermore, our analysis shows that absent the existence and exercise of market power, it appears unlikely that retail suppliers would have difficulty obtaining renewable generation (or credits) to meet an existing renewables requirement, or that there would be a significant market premium for existing renewables in the near term. In this scenario, Massachusetts's retail suppliers and customers would absorb the transaction and administration costs of an existing renewables program, without materially affecting the supply of renewables in the region.

Figure 6: Existing Renewable Supply vs. Demand for New England



1.3. Impact of RPS Design Options

The DOER must choose between several options for certain design elements of the RPS. We have examined the sensitivity of overall rate impact to specific design choices.

1.3.1. Regulatory Certainty Regarding Term of RPS Requirement

According to the Act, by the end of 2003, 1 percent of Massachusetts retail electricity suppliers' sales to end-use customers must be delivered from qualifying new renewable resources, increasing by 0.5 percent annually through 2009. After 2009, the percentage continues to increase at 1 percent each year until a date determined by the DOER.

This cost analysis assumes that the RPS will remain in effect well past 2009, that the RPS percentages increase to at least 7% by 2012 and are not reduced from this level for a substantial term thereafter, and that this schedule will be clear to investors and lenders providing capital to renewable projects. If the term of the RPS was uncertain, and developers and lenders perceived that it could abruptly end any time after 2009, new renewable projects would be more costly to develop. Specifically, projects would have to consider the possibility of a significantly reduced market for their renewable attributes after 2009. Projects would likely face some combination of a shorter financing period, a higher cost of capital, and higher required debt service coverage ratios, particularly as 2009 approaches. The net effect of such uncertainty would be to increase the "all-in" cost of power from new renewables and the cost of RPS compliance during the term of this analysis. This issue is discussed in *White Paper #7: Design Issues*[4].

1.3.2. Biomass Eligibility

Though the Act specifies that "low-emission, advanced biomass power conversion technologies…" are eligible for meeting the Massachusetts RPS for qualifying new renewable resources, it does not precisely define what specific biomass technologies, plant configurations, or emissions requirements must be met for a biomass resource to be eligible. DOER is evaluating a biomass emission limit per unit generation, likely applying to NO_x as well as particulate matter, as the defining criteria of low-emission, advanced biomass. As a result, the amount and cost of biomass resources available to meet the RPS will hinge on two eligibility questions (among others):

1. With respect to an *existing biomass plant that is retrofitted* to reduce its air emissions below the biomass emission limit, how much of the plant's generation should be eligible as new under the RPS? The base case analysis assumes that only incremental generation above actual 1995-1997 output would qualify as new. An alternative approach would qualify all output of the retrofitted plant as new, based on the interpretation that any historical production from *biomass* would not have constituted *eligible biomass* – hence all future generation is *incremental eligible biomass* if it meets the "low-emission, advanced" requirement. The result would imply a much greater quantity of potentially eligible biomass generation.

2. In an instance of *biomass co-firing at a fossil-fired generating plant,* what portion of the plant must meet DOER's proposed biomass emission limits? The base case analysis assumes that the entire plant – including the majority of output that is generated from non-renewable fuel - must meet the biomass emission limit. An alternative approach would require that only the portion of the plant's emissions that are imputed to be biomass fraction of production need meet the requirement, thus leading to a greater amount of eligible biomass potential.

For this scenario, two factors were varied simultaneously. First, for existing biomass plants that are retrofitted to reduce their emission rates, all future production was assumed to be eligible as new renewable generation (in the base case, only incremental production above a historical baseline was considered eligible). The effect of this change was to increase the amount of potential eligible production from retrofitted biomass plants, and to lower the cost per kWh to develop this resource. Second, for a coal facility that co-fires with biomass, only the air emissions imputed to the biomass portion of generation were required to meet emission rate limits (in the base case analysis, the plant's entire emissions were required to meet the biomass emission limit). The effect of this change was to increase the number of coal plants at which biomass cofiring would be possible.

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[4] Wiser, R., R.C. Grace. 2000. *Massachusetts Renewables Portfolio Standard White Paper #7: Design Issues*. Prepared for the Massachusetts Division of Energy Resources. 9 February.

These changes, which expanded the potential scope and reduced the estimated cost of some biomass resource options, resulted in a five to seven percent decrease in average cost of RPS compliance to Massachusetts end-use customers compared to the base case, as shown in Table 2.

Table 2: Percentage Decrease in Average Cost to MA End-use Customers for Different Biomass Eligibility

	2003	2006	2009	2012
Base Case	-7.0%	-5.7%	-6.8%	-5.1%

1.3.3. Product- or Company-Based RPS Requirement

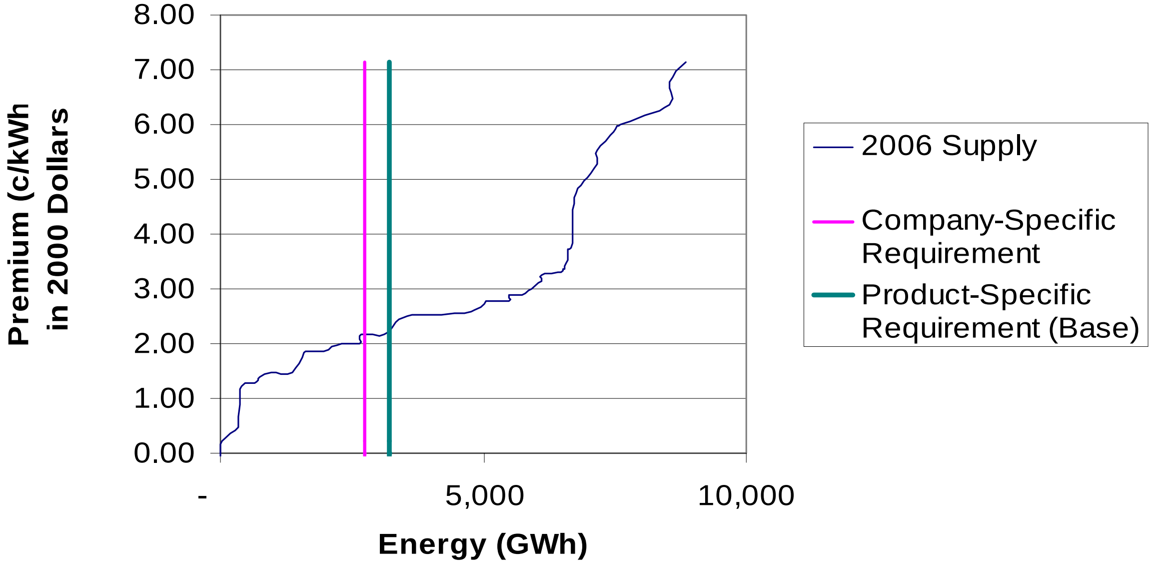
The Act clearly states that every retail supplier must comply with the RPS. It does not indicate clearly, however, whether a retail supplier must provide a minimum percentage of eligible renewables to each end-use customer (product-based compliance), or whether it may instead comply through providing eligible renewables to end-use customers in aggregate (company-based compliance). This issue is examined in *White Paper #1: Applicability*[5].

In the base case, we assumed that compliance would be product-based, thus requiring a minimum percentage of sales to each Massachusetts end-use customer come from eligible new renewable resources. In a sensitivity analysis, we explored potential cost differences between a product-based requirement and a company-based requirement. We assumed two specific changes for the company-based requirement. First, we assumed that retail suppliers would use any renewable power demanded by Massachusetts customers through green retail electricity products to meet the suppliers' minimum RPS requirements. In this situation green retail power purchases by Massachusetts customers would not represent incremental demand for renewables, and the total amount of renewables constructed would be lower than in the base case. The second change assumed in this case was that retail customers would become aware that green retail power purchases were not always supporting incremental renewable development, and that purchases of green retail products would decrease throughout the Northeast region.

Figure 7 shows that company-based compliance was estimated to result in a reduction of total renewable generation in 2006 by 474 GWh, or 15 percent, compared to product-based compliance. This is mainly due to the reduction of retail demand for green electricity products in New England and New York.

[5] Grace, R.C., and E. Holt: *Massachusetts Renewable Portfolio Standard White Paper #1: Applicability*, prepared under contract to DOER, November16, 1999.

Figure 7 Demand Decrease Due to Company-Specific RPS Requirement - 2006



The average cost of RPS compliance to Massachusetts end-use customers is shown in Table 3. In early years, company-specific compliance is estimated to be eleven to twelve percent less than product-specific compliance. However, in later years the difference is estimated to be only two percent less for a company-specific requirement. Although green demand is less, most of this impact is offset in later years because of the large amount of wind anticipated to be available near the marginal cost.

Table 3: Percentage Decrease in Average Cost to MA End-use Customers For Company-Based Compliance, Compared to Product-Based Compliance

	2003	2006	2009	2012
Base Case	-12.4%	-10.9%	-2.0%	-2.0%

1.4. Uncertainties and Implications of the Analysis

In this section, we identify several uncertainties that are inherent in an analysis of this type. We then highlight a number of important conclusions that emerge from our analysis of the potential costs of the Massachusetts RPS and discuss the implications that these conclusions suggest for DOER's RPS design choices.

1.4.1. Uncertainties

For several reasons, we recommend that the reader not place undue emphasis on the specific quantitative results of this analysis. First, the analysis deals with technologies and transactions that are essentially unprecedented on any significant scale in the Northeastern U.S. Second, this is a study of limited scope, based by necessity on numerous assumptions about a range of unknowns. A few of these uncertainties include:

- Fossil fuel prices that drive in large part the market value of generator output, and therefore the renewable generation premium;
- Policy (e.g., will there be other RPS requirements in the region? What will they look like?);
- Technology advance (e.g., rate of change of costs, project scales, efficiencies);
- Prospects for particular technologies (e.g., feasibility of off-shore wind projects; ability to permit new renewable generating sources; ability to permit co-firing at existing fossil plants; depth of resource at given prices; etc.); and
- Expenditures of system benefit charge funds on eligible renewables.

We feel that our forecast is fairly conservative; in Section 2.10.3 we describe those factors that could cause the projected base case RPS rate impact to be either lower (suggesting the estimate is conservative) or higher (suggesting the estimate optimistic). While we believe that actual outcomes are likely to fall within the bounds outlined in this analysis, we recognize the limitations of our ability to accurately predict results for immature technologies and markets. By providing a transparent picture of potential costs and impacts and identifying the important drivers, we hope that this analysis will help facilitate clear and productive dialogue among developers, retailers, and regulators.

1.4.2. Implications of the Analysis

With respect to the *supply curve analysis* for new renewables, it appears that sufficient new renewables will be available to retail suppliers for meeting RPS obligations, provided that suppliers promptly commit to purchases with sufficient lead-time for development and construction to occur[6]. Several tentative conclusions emerge as to the roles that particular technologies may ultimately play:

- Landfill gas appears fairly cost-effective, with among the lowest of estimated premiums, but appears capable of meeting a decreasing fraction of New England's growing need for new renewables during the next decade as limited development opportunities become saturated. Landfill gas is projected to meet approximately 84 percent of the renewable demand in 2003, thereafter declining to 32 percent in 2006, 20 percent in 2009 and 14 percent by 2012.

[6] It appears that sufficient development activity is occurring in the region; however, the lack of commitments by wholesale and retail marketers necessary to finance construction appear to be an impediment to project completion.

- Wind appears likely to play a leading role in the supply of new renewables. Substantial amounts of wind power are likely to be needed throughout the planning horizon, potentially straining the siting and permitting process throughout the Northeastern United States. We do not project any wind power is needed in 2003, but by 2006, wind fulfills 24 percent of the renewable requirement, rising to 27 percent in 2009 and 31 percent in 2012. Even with substantial amounts of wind power, however, it is likely that additional resources (beyond wind and LFG) will be needed as well.

- The feasibility, cost, and depth of new biomass-based resources (particularly co-firing of biomass fuel at fossil-fired plants) may be a critical driver of the shape of the supply curve for new renewables. As a result, the cost of the RPS to Massachusetts customers could depend strongly on the actual availability and characteristics of biomass resources, and on the DOER's decisions with respect to their eligibility.

- The rate of technological-advance-driven and scale-economy-driven cost decreases for renewable technologies is a major driver of RPS compliance costs in the long-term. We have made assumptions on a technology-specific basis regarding these advances, summarized in Appendix B.

- A number of potential renewable technologies eligible for the Massachusetts RPS were not evaluated in detail because our initial screening revealed that they would not likely be cost-effective in volumes sufficient to drive our analysis. These categories included solar photovoltaic or solar thermal electric energy, ocean thermal, wave, and tidal energy. Note that under a future resembling the High Compliance Cost Case, some of the other technologies (e.g., wave) could become cost-effective, providing additional depth to the right hand portion of the renewable supply curve. As discussed in Chapter 2, sufficient SBC funds targeted at higher-cost technologies could help bring them into the relevant portion of the supply curve**.** Finally, depending on the rate of technology improvement, fuel cells (either using renewable or non-renewable fuel) could play a greater role in the regional supply of new renewables than shown here.

While estimated incremental *transaction and administration costs* associated with the RPS are significant in absolute dollars, they are likely to have only a minimal and declining effect on Massachusetts retail electricity prices. As a component of overall RPS costs, administration and transactions costs average only a few percent in our analysis. As discussed in more detail in Chapter 2, the magnitude of these costs also appears to hinge to a large degree on the particular *accounting and verification system* that is chosen.

- The incremental costs attributable to the Massachusetts RPS will clearly be lowest if the Massachusetts RPS is implemented in coordination with a regional system of certificates in which generation attributes are tracked and traded on a centralized basis. While a regional attribute accounting system would be used for RPS compliance, the system would be developed for a range of purposes, including other state RPS, information disclosure, and emission performance standard requirements. This analysis therefore treats the majority of the development costs of such a regional certificates system as sunk, and not a component of the incremental cost of Massachusetts RPS compliance.

- If Massachusetts needed to develop its own system, renewable energy credits would likely to be the least costly option. A more costly option would rely on tracking title to resource attributes via contract path. This analysis assumes that market participants will be allowed to make discretionary allocations of attributes to which they have title to various energy sales, and that they develop fairly efficient markets and transaction methods (e.g., power exchanges, conversion transactions) for renewable attributes. This system would be along the lines of the "restricted unbundling" scenario described in *RPS Accounting & Verification Mechanisms and Policy Coordination Report, Part I: Accounting and Verification for Generation Attribute Requirements*[7]. If this did not occur, the transaction costs associated with a "contract path with restricted unbundling" system could be even greater than shown here and detailed in Chapter 2.

The potential existence of *emissions markets* may influence the cost of RPS. If new renewable generators are awarded emission reduction credits, allowances or offsets that are sold to create alternative revenue streams, the revenues required for renewable energy credits will likely be lower thereby reducing the cost of RPS compliance.

This analysis also indicates that *regulatory certainty* (or lack thereof) with respect to the term of the new renewables requirement could have a significant effect on RPS compliance costs. If financial markets do not have confidence that the RPS requirements will be maintained past 2009, renewable projects could face some combination of shorter debt terms and higher cost of capital, resulting in a higher "all-in" cost of power from new renewable projects.

Finally, with respect to *existing renewables*, the supply/demand relationship in Figure 6 indicates that over most of the study horizon, the projected supply of existing renewable generation in New England and its neighbors (New York, Quebec, and New Brunswick) greatly exceeds potential demand in New England and New York. Large fractions of the renewables in the supply curve either have operating costs below prevailing wholesale prices or are committed to long term power sale agreements at favorable rates. As a result, substantial attrition beyond that assumed in the low supply case seems unlikely.

Importantly, the existing renewable provisions of the Act refer to maintaining the fraction of Massachusetts's retail sales that is derived from renewables. The Act does not attempt to protect the stock of renewables for the region as a whole, and it is doubtful that Massachusetts alone could do so. Figure 6 indicates that even if significant attrition of renewables in the region were to occur, there would be adequate supply to meet a Massachusetts baseline requirement for several years. In this environment, and assuming that market power in renewable supply does not exist or is not exercised, it is unlikely that existing renewables would command a significant premium. The primary cost impact of implementing an existing renewable requirement in the near term would likely be transaction and administration costs.

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[7] Grace, R.C, R.H Wiser, B. Abbanat. 2000. *RPS Accounting & Verification Mechanisms and Policy Coordination Report, Part I: Accounting and Verification for Generation Attribute Requirements.* Prepared for the Massachusetts Division of Energy Resources. March 2.

1.5. Organization of This Report

- Chapter 2 describes in detail our analysis of the new renewable requirements portion of the Massachusetts RPS.
- Chapter 3 describes our analysis of the baseline (i.e., existing) renewable requirements portion of the Massachusetts RPS.
- Chapter 4 describes additional sensitivity analyses that were performed to inform specific DOER design choices with respect to the new renewables requirement.
- Appendices 1 through 3 present further details of some input assumptions and results presented in Chapters 2 through 4.

2. NEW RENEWABLE REQUIREMENTS IMPACT ANALYSIS

2.1. Overview

The Massachusetts Electric Utility Restructuring Act[8] requires that the Massachusetts Division of Energy Resources (DOER) develop and implement a renewable energy portfolio standard, or RPS, to be applied to retail suppliers of electricity to end-use customers in the Commonwealth.

To complement the process of developing the design details of the RPS, this paper summarizes an analysis of the potential costs and impacts of the RPS. The approach taken for this analysis was first presented in *White Paper #9: Evaluation Methodology***.** Overall, the analysis was guided by two basic goals. First, from an agency accountability perspective it is generally good practice for state agencies to evaluate the potential costs and impacts of the policies that they develop and implement. Second, from an RPS policy design perspective, a policy-analysis tool that can evaluate the costs and impacts of different possible approaches to structuring and applying the RPS may help inform the DOER's RPS design decisions. Finally, a transparent analysis may inform and influence the actions of market participants as they prepare to meet the RPS standard.

Overall, we focused on two key questions under high, low and base-case scenarios of cost-drivers:

- What range of impacts can be expected to result from the minimum new renewables requirements in the Act, in terms of incremental renewable energy generated, rate impacts to retail electricity customers in Massachusetts, and emissions displaced?
- What is the potential impact of a requirement to maintain the baseline fraction of renewable resources historically included in the supply to Massachusetts's customers prior to the Act?

The analysis itself is structured to quantitatively estimate the costs and impacts of the Massachusetts RPS under a "base case" outlook, and to test the results under alternative scenarios composed of sets of assumptions for key variables. We focused on the costs and impacts that will be experienced by Massachusetts electricity customers for four "snapshot" years: 2003, 2006, 2009 and 2012 to present a reasonable picture of how developments, costs and impacts unfold over time.

The estimated costs of the RPS program are comprised of three components:

- ***Incremental Renewable Generation Costs:*** The incremental cost of renewable energy or renewable energy credits needed to comply with the RPS. This cost will depend primarily on

[8] Chapter 164, of the Acts of 1997 – "AN ACT RELATIVE TO RESTRUCTURING THE ELECTRIC UTILITY INDUSTRY IN THE COMMONWEALTH, REGULATING THE PROVISION OF ELECTRICITY AND OTHER SERVICES, AND PROMOTING ENHANCED CONSUMER PROTECTIONS THEREIN", Approved November 25, 1997 (hereafter "Restructuring Act").

the difference between the "all-in" cost of power from renewable generating sources and the marginal cost of power from non-renewable sources.

- ***Transactions Costs:*** The wholesale (generator and/or broker) and retail (retail supplier) transactions costs related to the personnel and resources needed to buy and sell renewable energy to comply with the RPS.
- ***Administrative Costs***: The incremental start-up and ongoing costs of administering the RPS, from both supplier and administrator perspectives.

In addition to estimates of ratepayer costs, the analysis also provides a more limited quantitative and qualitative assessment of other possible impacts, including the amounts of renewable resources developed as a result of the Massachusetts RPS and regional air emissions displaced by the renewable generation. This chapter provides information of the approach, assumptions, and results of the cost and impact analysis of the Massachusetts RPS for qualifying new renewable resources.

2.2. Basic Approach

The cost analysis for the new renewables RPS was conducted through the following steps:

1. Estimate the *demand for new renewables* in New England and New York, including that needed to meet the Massachusetts RPS[9];
2. Estimate the cost and depth of supply for specific qualifying new renewable sources, and derive a composite *supply curve for new renewables*;
3. Using the supply and demand curves, estimate the *incremental cost of renewable generation*;
4. Estimate the potential *administration and transaction costs* associated with the Massachusetts RPS.
5. Based on the results above, estimate the *total costs* and *rate impact* of the RPS, as experienced by Massachusetts customers.

We performed a sensitivity analysis to simulate possible high, base, and low-cost scenarios. Emissions displacement analysis was performed to estimate some of the public benefits that the Massachusetts RPS for qualifying renewable energy resource might create.

The remainder of this chapter presents the components of the cost and impact analysis in detail.

[9] We have ignored demand in Quebec and New Brunswick, as there is no retail choice or regulatory requirement in these regions, while new renewable generation is likely to be developed in these regions to meet demands in the U.S.

2.3. Demand for New Renewables

In the Northeast, there are currently two mandated requirements[10] for new renewable generation: one in Massachusetts and one Connecticut. Each state's restructuring legislation requires a specific, increasing amount of retail sales to be derived from eligible technologies over several years[11], as shown in Table 4. The eligible renewable technologies in Connecticut and Massachusetts overlap considerably, although not entirely. Customer-driven green power demand may stimulate additional demand for these same renewable technologies. Because overall region-wide renewable energy demand conditions will affect the cost of the Massachusetts RPS, it is appropriate to assess the supply and demand for new renewables on a regional basis. We estimated the demand for new renewables in each snapshot year as the sum of the Connecticut and Massachusetts RPS requirements, plus an estimate of potential consumer-driven demand for new renewables through purchases of "green" retail electricity products.

Table 4: New Renewables Requirement for CT and MA (As Percentage of Retail Sales)

Timing	CT Requirement	Timing	MA Requirement
Before 7/1/01	0.50%		
7/1/02	0.75%		
7/1/03	1.00%	Before 12/31/03	1.0%
7/1/04	1.50%	12/31/04	1.5%
7/1/05	2.00%	12/31/05	2.0%
7/1/06	2.50%	12/31/06	2.5%
7/1/07	3.00%	12/31/07	3.0%
7/1/08	4.00%	12/31/08	3.5%
7/1/09	5.00%	2009	4.0%
7/1/10	6.00%	2010 and after	Add 1% annually

[10] Maine has a renewables requirement that covers both new and existing renewable energy technologies. Due to the supply surplus of facilities eligible under Maine's standard, it is not anticipated to create a sizable enough incentive to encourage the supply of new renewable resources; it is therefore not included as a requirement for new resources in this analysis. Other states are considering implementing a state RPS, but none were passed at the time of this analysis.

[11] At the time this analysis was developed, it was uncertain if the Connecticut RPS would apply to the standard offer supplier. We assumed that the RPS applies to all suppliers in the analysis. Recently, Connecticut ruled that it does not apply to the standard offer supplier. While there have been attempts to revise applicability to include the standard offer, this change has not yet occurred. Should the Connecticut rules remain unchanged, the renewable generation premium and rate impacts would likely be lower than our projection in 2003; however, because the Connecticut standard offer expires in 2004, this potential disparity is short-lived.

Retail electricity sales for each state were taken from the Energy Information Administration (EIA) for 1998 and escalated according to the regional growth rates found in the 1999 NEPOOL Forecast Report of Capacity, Energy Loads and Transmission ("CELT") document.[12] The resulting Massachusetts and Connecticut RPS requirements for new renewable generation amounts to almost one million MWh per year by 2003 and up to 6.6 million MWh by 2012.

To date, Massachusetts municipal light plants (MLPs) have not opted to participate in retail choice. This analysis assumes that MLPs that represent half of the total municipal retail sales will elect to opt-in to retail choice by 2003, and that all will opt in by 2012. We further assume that retail sales within MLPs who have restructured will be subject to the new renewable requirement, contributing to an increase in demand for new renewables over the horizon of this analysis.

In addition to the defined requirements associated with state RPS programs, some demand for new renewables is anticipated from residential, commercial and industrial end-use customers who are willing to pay a premium so that some or all of their electricity comes from renewables. We developed a regional estimate (including New York) of this "green" power demand, since renewable demand from outside - but still within reasonably cost-effective transmission distance of - Massachusetts will essentially compete for the same new renewable projects available to Massachusetts. Due to different start dates for retail competition, and markets unattractive to retail sellers (in some jurisdictions), we assumed that green demand in each state in the Northeast will begin according to the timeframe listed in Table 5.

Table 5: Start date for non-RPS green demand of new renewables

	State	Beginning of green demand (yr.)
New Eng.	CT, ME	2000
	MA, RI, NH *	2001
	VT	2004
Other	NY**	2001

* MA and RI markets "opened" in 1998, but competition (and hence green marketing) were very limited due to relatively low standard offer prices. The largest utility in New Hampshire recently settled out of court, amending the state's electric restructuring legislation; we therefore assume that retail competition will begin there in 2001

** NY has staged opening starting in 1999. We assumed that green marketing would begin in 2001.

[12] ISO New England. 1999. *NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission (CELT) 1999-2008.* Prepared for the Market Reliability Planning Committee, April 1. Available at http://www.iso-ne.com/main.html.

An important challenge in estimating the potential influence of green power demand is that markets with active competition for retail customers (CA and PA) are still quite young and their markets are structured differently than those in New England. Yet these markets provide most of the available data points for the early years of competition, so we extrapolated their experience to the Northeast while noting the great uncertainty in these estimates. We assumed the following percentage of total residential customers (i.e. customers who shop for a new retail power provider, as well as those who do not) would choose green renewable products above the RPS: 2 percent in year 3; 4 percent in year 8; 6 percent in year 13; and 8 percent in year 20. To account for commercial and industrial demand, we added an additional 25% of the residential demand figures above. Note that the resulting percentages could be achieved by any combination of customer shopping rates and preferences for green power[13].

Only a portion of the estimated green demand was assumed to be from new renewable sources; the remainder could come from a combination of existing renewables and non-renewable sources. Using the Green-e certification requirements as a guide, we assumed that on average 50% of the content of each electricity product would derive from renewable resources; Table 6 shows the percentage of new renewable generation that was assumed in the average product.

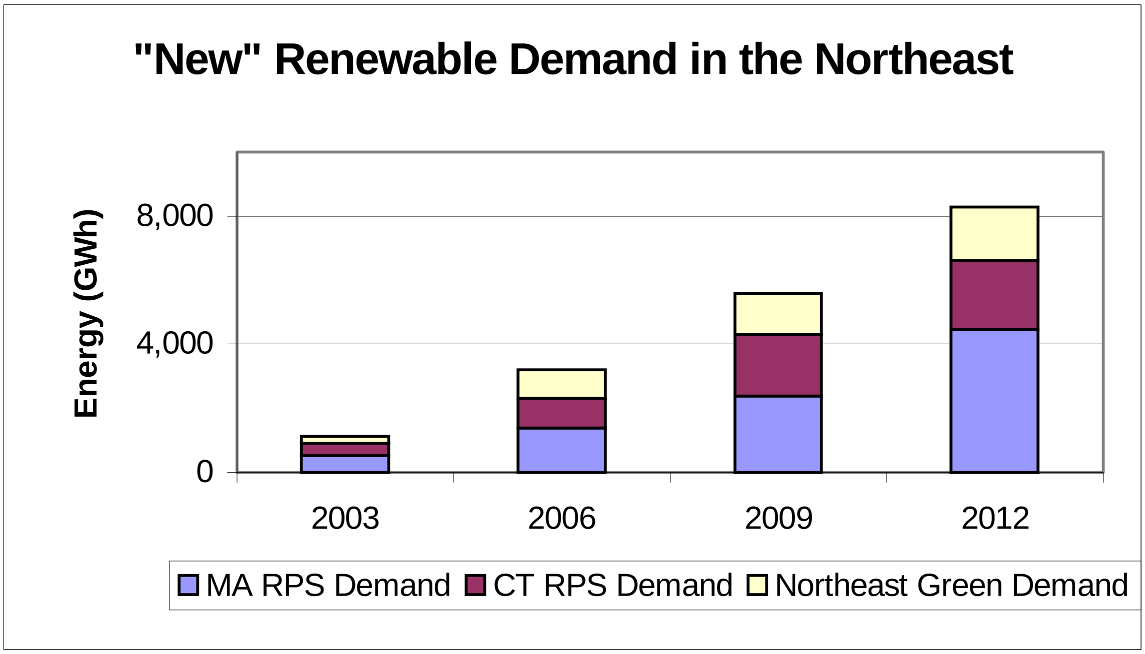
Table 6: Percentage of New Renewable in Green Marketing Products

YEAR	1	2	3	4	5	6	7 and on
% new RE	0%	5%	10%	15%	20%	25%	25%

The estimates of RPS-driven demand and consumer-driven demand described above were summed to obtain the total regional demand for new renewables in each of the snapshot years. Figure 8 summarizes the results.

[13] For example, a 5 percent green demand could be achieved if 25 percent of customers shop and 20 percent of those shoppers choose green power, or if 50 percent of customers shop and 10 percent of the shoppers choose green.

Figure 8: Estimated Drivers of New Renewable Demand



2.4. Supply of New Renewables

Most of the costs associated with the new renewables requirements of the Act will be incremental renewable generation costs, relative to generation costs in the absence of an RPS requirement. Using a range of information sources, we developed estimates of the approximate quantities of energy from each eligible type of renewable generation that could be developed for delivery in each year analyzed, and the approximate cost of energy (including a required profit margin) from projects of each technology type. We estimated the initial capital costs, fixed operation and maintenance (O&M) and variable O&M costs using a range of sources, including:

- "Renewable Energy Technology Characterizations," EPRI/DOE; 1997
- "Scoping Study of Renewable Electric Resources for Rhode Island and Massachusetts: Volume 1: Technology Assessments," C.T. Donovan Associates, 1997
- "Profiles of Leading Renewable Energy Technologies for the Massachusetts Renewable Energy Trust Fund," Arthur D. Little, 1998
- Experience and familiarity of the authors with existing and proposed renewable projects and development activity in the Northeast; and
- Discussions with several of DOER's RPS Advisory Group participants.

<u>2.4.1. Renewable Energy Technologies Considered</u>

This analysis focuses on the new renewable technologies that, based on an initial screening, appear most likely to cost-effectively meet the Massachusetts RPS renewable energy purchase obligations. Technologies that do not appear to be competitive based on cost, or that do not appear likely to be developed in significant quantities, were not analyzed in detail. Appendix B contains a 1-page summary of the key assumptions about the available supply and cost of power from each of the technologies that passed our initial screening.[14] A summary of our key technology assumptions includes:

- <u>Landfill methane</u>
  - We assumed that the quantity is limited by the amount of capped landfill capacity at any given time, and that a relatively high fraction of landfills in the Northeast would be tapped, yielding up to 224 MW of capacity by 2012.
  - Large landfill gas projects and small projects were evaluated separately, because their economics are different. Many large landfills were required to install methane gas collection systems, some of which are eligible for a Federal tax credit and all of whom have scale economy advantages over smaller landfills. We also assumed a large improvement in technology efficiency, since landfills currently burn their methane almost exclusively in diesel generators, but could also use microturbines and fuel cells in the later years of the analysis, which generate electricity with significantly higher efficiency.
- <u>Wind</u>
  - There is a significant uncertainty about the potential for this resource, due to a combination of technological potential, siting capability, project scale, interconnection costs, and readiness of offshore resources. Projections of available energy were built upon assumptions of projects currently known to the authors to be in various stages of development[15] as a foundation for 2003 and 2006 (over 650 MW). This was supplemented by unidentified projects starting in 2006 (an additional 1650 MW by 2012), resulting in total potential capacity of 2300 MW in 2012. We assumed that the feasible wind development within New England is initially limited, so that much of the early supply will come from NY and/or Quebec. We've assumed that over time, additional resources will become available in New England. There is also a fairly wide range of potential costs, driven by varying wind speed, other factors identified above, as well as Federal production tax credit (PTC) eligibility. For the base case, we assumed PTC would be extended at a 0.5-cents/kWh level for projects that are developed between 2001 and 2006.

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[14] Note that potential capacity described below and in the Appendix presents is the total estimated to be available from each technology. Not all of the available capacity from each technology will necessarily be needed to fulfill the RPS new renewables requirement.

[15] We probability derated these projects based on the authors' judgment of the likelihood of success in receiving permits and achieving commercial operation.

- *Biomass*

The Act defines biomass as "low-emission, advanced biomass power conversion technologies." Currently, the DOER is evaluating a biomass emission limit for NO_x (which we assume to be in the 1.5 – 2.0 lb./MWh range) and particulates (not yet specified, but likely to be less binding than a NO_x requirement). Biomass resources considered in this analysis were assumed to meet the biomass emission limit, as defined in the base case. Biomass generation was projected to come from several configurations:

- Co-firing as a solid in coal plants, and in a gasification configuration with plants capable of burning natural gas. The estimated costs associated with co-firing include: (1) incremental fuel costs (i.e., the difference between the cost of wood fuel and the plant's primary fuel); (2) an initial capital investment for fuel handling or gasification equipment, (3) O&M costs to handle the biomass fuel; and (4) any additional operational improvements in efficiency needed to decrease emissions.[16] The ultimate role of co-firing will depend on the ability of fossil-fired plants to obtain or modify the necessary permits. We assumed that the installation of co-firing would not be considered a major modification under the Clean Air Act (potentially triggering New Source Performance Standards). We assumed that by 2012, up to 2,000 MW of coal plants could co-fire at a 10 percent rate with solid biomass (yielding 200 MW of potential biomass production) and another 1,500 MW could co-fire with gasified biomass (yielding 150 MW of potential biomass production).

- Repowering of existing or retired fossil-fired power plants. We assumed that one or two smaller plants could be repowered using biomass fuel (ultimately amounting to 100 MW total capacity), and that capital investments in emission control equipment would need to be made in order for a plant to qualify as a low-emission biomass source.[17]

- Increased production from existing biomass plants meeting (or retrofitted to meet) the biomass emission limit. We assumed that 150 MW of existing biomass capacity that did not operate as baseload units during the 1995-1997 period could increase their annual average capacity factor from 30 percent to 80 percent. This option has the potential to provide incremental renewable generation much less

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[16] Due to the recent decision by the DC Appellate court, 19 states (including MA, NY and RI) are required by the EPA to file state plans to decrease their NO_x emissions. As a result, we estimated that several coal plants would have to take action to meet these more stringent regional emission requirements and that these plants will be the ones most willing to consider biomass co-firing. The incremental cost of implementing co-firing at such plants would therefore not include the sunk cost of emission control equipment needed to meet the RPS emission requirements.

[17] Conceivably, the premium for renewables could rise to such a level that a larger operating coal plant would consider shifting its entire operation from coal to biomass. We chose not to include this potentially large source of repowered biomass, based in part on questions about whether a biomass fuel supply for a much larger scale facility would be achievable at reasonable cost.

expensively than a newly constructed biomass plant. The primary costs of this option are incremental fuel/O&M and emission control retrofits.[18]

- <u>"Greenfield" biomass plants</u> using direct combustion as well as gasification technologies. Initially direct combustion looks more cost-effective, while gasification may improve over time as technology improves, particularly if actual biomass fuel prices are relatively high. Cost and availability of biomass fuel in the region may limit the total potential of new biomass facilities; we assumed that significant volumes of sustainable forestry waste would be available at a delivered price of $3.50/mmBTU.[19]

- <u>*Fuel Cells*</u>

  - We assumed that fuel cells would be commercially available in large enough quantities that their capital costs would decline substantially over the next decade, consistent with a scenario outlined by Arthur D. Little in their renewables analysis performed for the Massachusetts Technology Collaborative[20]. Under this outlook, fuel cells using natural gas (which are eligible under the Connecticut RPS but not the Massachusetts RPS) could become competitive with total retail electric rates by 2006. In all scenarios we assumed that fuel cells using natural gas could provide up to one percent of the Connecticut RPS requirement for new renewables in 2006, growing to 25 percent of the requirement (or about 58 MW) by 2012.[21] Note that in actual practice, many fuel cells would be implemented behind-the-meter at residential, commercial and industrial installations, each of which would probably require a shorter payback period than a wholesale generating company. As a result, the effective cost of power from behind-the-meter fuel cells could turn out somewhat higher than shown here. On the other hand, retail customers with favorable thermal loads or requirements for uninterruptible power may install fuel cells before they are cost-effective relative to electric rates. Both of these impacts may merit further study.

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[18] We understand that installing new emission control equipment at some existing biomass plants could prove difficult based on the plant layouts. We assumed here that such challenges could be overcome at most New England plants.

[19] Preliminary draft information updating biomass cost and resource used in AEO 2000 that will be used in AEO 2001. Conversation with Zia Haq, Energy Information Administration, U.S. Department of Energy, June 12, 2000.

[20] Arthur D. Little, Inc. 1998. *Profiles of Leading Renewable Energy Technologies for the Massachusetts Renewable Energy Trust Fund.* Prepared for the Massachusetts Technology Collaborative. October.

[21] As noted earlier, fuel cells using renewable fuels (e.g. landfill methane), which are eligible in Massachusetts and could be economic in later years, were considered in the landfill methane section.

- *Other Renewable Energy Technologies:*

  - Some eligible renewable technologies were not evaluated in detail because initial screening revealed that they would not likely be cost-effective in volumes sufficient to drive the analysis. These categories included solar photovoltaic and solar thermal electric energy, ocean thermal, wave, and tidal energy. For example, we expect solar photovoltaic installations to result from consumer-driven "green" demand, but probably not in quantities that would significantly affect the regional supply curve during the term of this analysis. Note that sufficient SBC funds targeted at higher-cost technologies could potentially bring such resources into the relevant portion of the supply curve. Further, we assume only a minor role (as part of the landfill gas resource) for fuel cells, which must use renewable fuel to be eligible for the Massachusetts RPS. Fuel cells using other fuels (e.g., pipeline gas) are eligible in Connecticut, and states that define new RPS requirements could possibly include fuel cells as eligible resources. Fuel cells could therefore play a more significant role in the regional supply of new renewables, particularly if the cost of the technology declines rapidly or renewable premiums turn out to be relatively high.

  - For the supply curve analysis, we recognized that some amount of behind-the-meter renewables with higher per-unit costs than the large-scale options presented here will probably be developed. These sources could include photovoltaic installations, as well as small-scale biomass or wind projects. We assumed that 21.9 GWh (equivalent to 2.5 MW at 100% annual capacity factor) of such would be developed by 2012, contributing to the supply irrespective of their per-unit cost. This amounts to several tenths of one percent of New England's total requirements for new renewables.

2.4.2. Wholesale Market Clearing Price

We estimated the "all-in" cost of power for each of the technologies described above. The all-in cost includes fuel costs (as applicable), fixed and variable O&M costs, and the project's initial capital investment. Projects coming online to meet the RPS requirement were assumed to recover their capital investment through an annual carrying charge of 17 percent, which remains constant in real terms through the analysis. This assumption is consistent with a target return threshold of 16 percent over 20 years, a debt term of 12 years and a 60/40 debt/equity ratio. The same carrying charge was applied to all renewable technologies.

We then estimated the revenue that each type of renewable project could obtain from the generic wholesale commodity power market (i.e., assuming no value for the project's renewable attributes, nor for potential emission benefits). The commodity market value of production from renewables was estimated based on a 1999 La Capra Associate's simulation of the New England electricity market, using the PROSYM dispatch simulation software.[22] Table 7 summarizes the

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[22] As part of this cost and impact analysis, we projected potential emission reductions associated with introducing new renewables into the regional electricity market; our goal was to illustrate the tons of physical emissions avoided. We did not adjust the rate impact estimate for two reasons: (1) allowance costs (i.e. of emissions) were implicitly

projected average electricity prices for peak and off-peak hours in each year analyzed. In the long term, the forecast is driven by the estimated cost of power from new merchant combined cycle plants burning natural gas; Table 8 presents the assumed natural gas prices (delivered to baseload electric generators in New England) used to develop the electricity price forecast. As discussed further in Section 2.11.2, the actual premium to renewable generators can be expected to vary inversely with actual wholesale electricity prices.

Table 7 Annual Average Wholesale Market Prices for New England

C/kWh ($2000)	2003	2006	2009	2012
On-peak	4.38	4.72	4.71	4.71
Off-peak	2.39	2.56	2.50	2.50
All Hours	3.34	3.58	3.55	3.55

Table 8 Natural Gas Price Used in PROSYM Wholesale Market Model

$2000/MMBtu	2003	2006	2009
Natural Gas Price	3.32	3.46	3.55

The commodity market value of production from each renewable technology was varied based on the assumed timing of energy production by season and time of day. This method assigns greater value to resources with a greater proportion of on-peak production, and to those capable of varying output on demand. In addition, a greater proportion of output from dispatchable projects (e.g. biomass) was assumed to occur during high-value on-peak periods than from projects with intermittent output (e.g. wind). For example, landfill gas – which was assumed to produce at essentially a constant rate throughout the year – was assumed to achieve average commodity market value of about 3.5 cents/kWh in 2003. Technologies with intermittent output and/or lower output during summer months were assigned values between 3.1 to 3.4 cents/kWh. While these variations in commodity market value per kWh are noticeable, they are much less important than the variances in estimated cost per kWh to produce power from the various renewable technologies.

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included in the bids of fossil-fired electric generators and therefore in wholesale electricity market revenues and (2) our analysis was not meant to be a full-scale societal cost analysis, as described in *White Paper #9: Evaluation Methodology*. Finally, we did not assume that generators would include an opportunity cost for CO_2 emissions in their bids.

For all renewable technologies tested, the estimated "all-in" generation cost exceeded the estimated wholesale value of its output. This difference represents the incremental revenue or premium that the project would need to obtain from its renewable attributes in order to be economically viable. [23] We assembled the estimated quantities of renewable generation by source and the combined results represent a *supply curve* for qualifying new renewable generation in each snapshot year.

2.4.3. Impact of State SBC Funds

We also considered the potential impact upon the RPS that might result from the activities and expenditures of system benefit charge (SBC) funds targeted at accelerating the role of renewable resources. Currently, such renewables funds exist in Massachusetts, Connecticut, Rhode Island, New York and New Jersey. In general, these funds have not addressed the potential interaction with RPS requirements or the resources to be used to meet the RPS requirements.

Regardless of how these funds are ultimately disbursed, there are at least two potential major categories of effects on the RPS: lower renewable technology costs, and greater quantities available. In developing costs and quantities of resources to creates supply curves, we have ignored the effect of SBC funds not already earmarked for certain projects[24]. We believe that the regional SBC funds are likely to have at least some impact on the cost of RPS, but the targets for future SBC funding are highly uncertain at this time. Therefore, we have made an adjustment to reflect the impact of SBC renewables funds on the cost of the RPS in a more generalized fashion.

Over the course of our study period, SBC charges earmarked towards supporting renewables development and market penetration amount to over several hundred million dollars. We expect substantial portions of these funds to be invested in activities such as education or other market pull, manufacturing ventures that will sell their products beyond the region, target resources not eligible for RPS (such as fuel cells) or in other ways that will not directly influence the RPS. However, it is reasonable that many of the SBC-funded programs will serve to reduce the ultimate cost of RPS-renewable resources, either directly or indirectly, through grants, production credits, infrastructure investments, debt or equity financing under favorable terms, or other mechanisms.

These funds are still in the early stages of planning their programs, so it is difficult to analyze their impacts with much precision. So, to approximate the potential magnitude of the impact of SBC funds on RPS compliance costs, we approximated the magnitude of the impact as follows. If the SBC funds wished to lower the cost of the RPS directly or indirectly by \$1/MWh throughout our study horizon, they might create programs that have the effect of a \$1/MWh

[23] The one exception is fuel cells, a technology we assumed would be implemented behind the meter and would therefore be measured against a customers total *retail* electric rates (which include not only market generation prices, but also transmission, distribution and stranded generation costs). While photovoltaics would also be expected in behind-the-meter configurations, they were addressed in the analysis as additions irrespective of their economics, as described above.

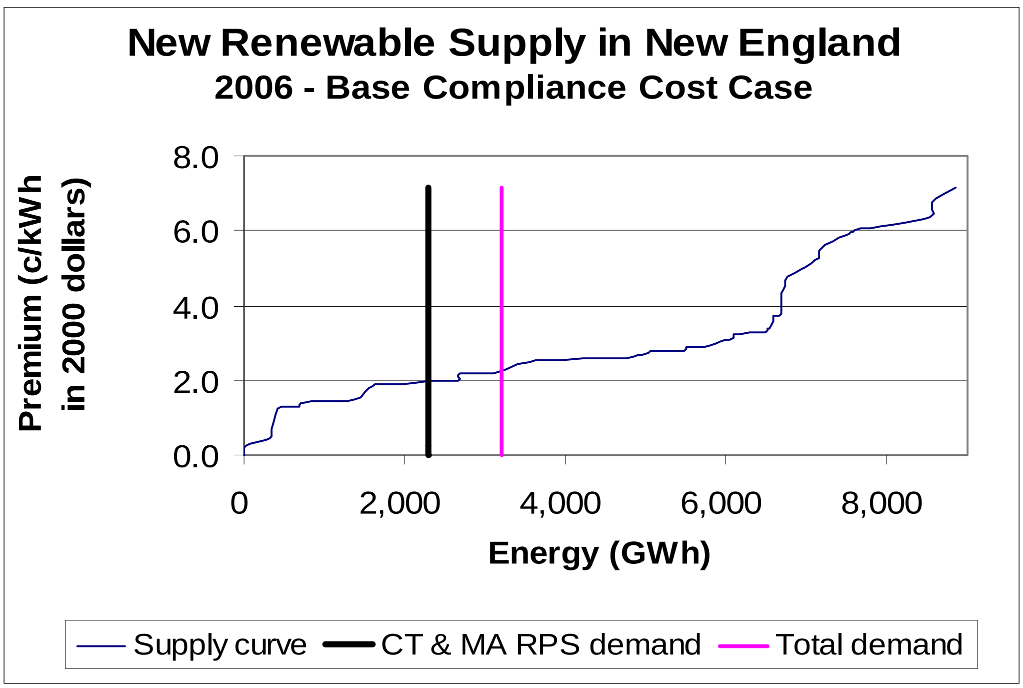
[24] Several funded wind projects in New York were considered in the analysis.

subsidy for the first 10 years of renewable production from any plant likely to set the clearing price. If the SBC funds had to subsidize 30 percent of all incremental generation in each year in order to ensure that they covered the marginal (clearing price-setting) plants, this might cost about $26 million (in 2000$). Given this analysis, it is not unreasonable to assume that SBC funds could reduce the clearing price by about $3/MWh throughout the entire study period by expending about NPV $75m, or about a third of the available funds, on RPS-eligible renewables. Potentially, SBC funds could be used to target marginal renewable resources, such that they could noticeably reduce the clearing price. This is would be a good topic for further study, particularly as SBC spending priorities become apparent.

2.5. Interaction of Supply and Demand

Figure 9 illustrates the estimated supply and demand curves[25] for the year 2006 under a base case outlook. The X-axis represents the cumulative amount of generation per year available from the new renewable resources examined; the Y-axis represents the premium (i.e., the difference between total resource cost and generic wholesale revenues) at which the generation could be available to meet demand in that year.

Figure 9: Estimated Renewable Generation Premium (base case)



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[25] Note that since the RPS-driven demands are prescribed as specific fractions of retail load, and they will not vary based on price, the estimated demand "curve" for new renewables in each year is a single quantity represented as a vertical demand curve. In actual practice, the consumer-driven portion of renewable demand can be expected to vary with price, and the top portion of the demand curve would be negatively sloped. In addition, banking or other flexibility mechanisms might also enable some price response, thereby making the demand curve slope somewhat.

We included two demand lines in Figure 9: one depicting the estimated required demand from the Connecticut and Massachusetts RPS requirements and the second ("total demand") that also includes consumer-driven green demand. The difference between the two emphasizes that the majority of projected demand for new renewable generation is anticipated to be from mandated requirements, based on our assumptions. We assumed that the necessary supply would fulfill demand needs in aggregate, depending on the cumulative amount of renewable energy demanded. This approach implies that the cost of renewables to supply green power demand is equivalent to that used to meet RPS requirements. While this approach is a simplification, it is likely to be conservative. This is because sources used to meet green power may at times be more expensive sources than those used to meet RPS (which will tend to be the lowest cost sources available). If higher-cost renewables are thereby brought into the mix, the supply curve would be shifted, resulting in lower-cost renewables setting the clearing price for remaining demand.

Appendix C presents the supply and demand curves for each year analyzed, along with tables detailing the quantities and prices of renewables that make up each year's supply curve. A summary of the energy and generating sources projected to meet the new RPS requirement for each snapshot year is shown in Table 9.

Table 9 Technologies Projected to Meet Northeast Renewable Demand, by Technology and Snapshot Year

Energy (GWh)	2003	2006	2009	2012
Landfill methane	955	1,254	1,893	1,997
Biomass combustion	177	656	663	669
Fuel cells (CT only)	0	26	263	535
Generic PV. Etc.	0	5	11	22
Bio/gas co-fire	0	407	830	1,281
Bio/coal co-fire	0	93	432	1,191
Wind	0	765	1,492	2,580
TOTAL	**1,132**	**3,206**	**5,584**	**8,276**

As shown in Table 10, landfill methane is expected to play a significant role in meeting renewable demand in the Northeast. As the CT and MA State RPS requirements increase over time, and technology costs decrease, wind turbines are expected to capture a significant portion of the market in the later years. Biomass as a whole will probably also play a major role, through several different technologies.

Table 10 Percentage Contribution from Each Renewable Technology Towards Meeting Projected Renewable Demand in the Northeast.

Energy (% of total)	2003	2006	2009	2012
Landfill methane	84.4%	39.1%	33.9%	24.1%
Biomass combustion	15.6%	20.5%	11.9%	8.1%
Fuel cells (CT only)	0.0%	0.8%	4.7%	6.5%
Generic PV. Etc.	0.0%	0.2%	0.2%	0.3%
Bio/gas co-fire	0.0%	12.7%	14.9%	15.5%
Bio/coal co-fire	0.0%	2.9%	7.7%	14.4%
Wind	0.0%	23.9%	26.7%	31.2%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**

2.5.1. The Incremental Cost of Renewable Generation

The marginal incremental cost of renewable generation, which we will refer to as the **renewable generation premium** (RGP), is estimated for each year of the analysis as the cost indicated by the intersection of the estimated supply and demand curves. Depending on the accounting system used, the RGP could represent the renewable *premium* associated with purchasing renewable energy, or the price of a renewable energy credit or certificate for RPS-eligible new renewables. The key features of this RGP estimate are:

- A marginal cost approach. The clearing price for RGP reflects the premium associated with the most expensive unit needed to meet the demand, and all renewable attributes receive the market-clearing price.
- An equilibrium approach. As explained above, the all-in cost of energy from each renewable technology was calculated assuming that all fixed costs associated with the initial capital investment are spread over a 20-year period using an annualized carrying charge that is constant in real terms.

The value of this approach is that over time, the new renewable market entrants that are needed to meet the RPS requirements will achieve approximately the revenues needed to cover their initial investment and ongoing operating costs, plus a profit margin. On the other hand, the incremental cost of renewable generation is likely to differ from the estimated RGP prices for several reasons:

- Temporary imbalances in supply and demand may occur, caused by changes in demand growth, delays in anticipated renewable projects, scarcity or instances of oversupply. The effect may be prices that fluctuate significantly above and below the equilibrium prices estimated in this analysis. To the extent that banking provisions are adopted, the magnitude of these variations could be tempered.

- Actual technology costs, performance, or (particularly) depth could turn out differently, particularly over time.
- Fuel costs for biomass supply will fluctuate over time.
- Carrying charge assumptions represent a meaningful and consistent but simplified view of long-term pricing in a competitive market. Factors such as financing structure, debt term, minimum debt service coverage requirements, and the economic life over which renewable projects are evaluated will impact the decision on whether to build a plant. Once that plant is operational, the market will dictate what price can be successfully charged, and any plant once built will continue to operate so long as its cash-flow allows (and perhaps beyond, under protection from creditors). As such, a carrying charge approach better reflects the price associated with long-term contracts.

The simplifying assumption that all generation in a particular year will receive that year's RGP is consistent with a situation in which all generators sell their output to the spot market, at a single price that is sufficient to support the highest-cost entrant. In actual practice we would expect most renewable projects to sell substantial fractions of their output and/or renewable attributes under multi-year contracts, at prices that meet their project-specific financial requirements. The upward sloping supply curve in our analysis indicates that many renewable projects would be viable at prices noticeably below the annual RGP, which is defined by the highest-cost entrant needed in each year. To the extent that such projects sell their attributes under long term contracts at prices below the price required by the highest-cost entrant, the average costs for retailers to acquire their RPS requirements could turn out lower than the RGP. While a detailed analysis of the bidding behavior of market participants is beyond the scope of this analysis, it may be a suitable topic for future study by the DOER.

Figure 10: Base Case Renewable Generation Premium

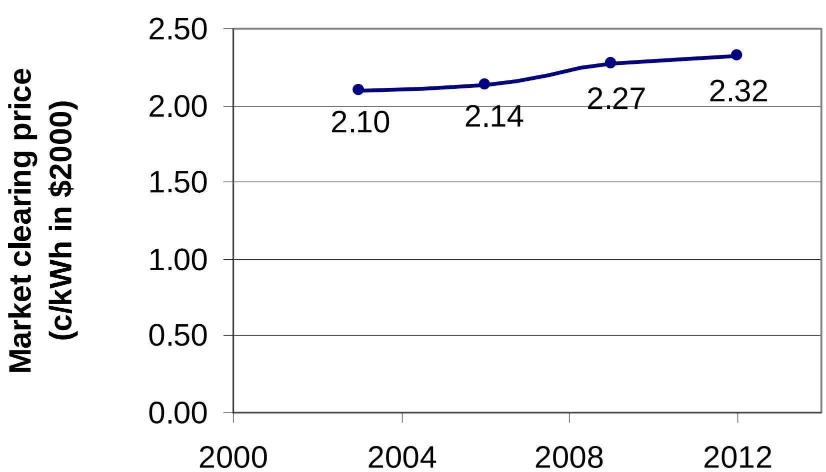

Figure 10 illustrates the estimated trend over time for the renewable generation premium based on each of the years analyzed. Note that the increase in costs over time occurs despite declines in technology costs driven by technological advance and economies of scale, due to the increased demand pressure that forces higher cost generators on the supply curve to set the market-clearing price.

2.6. Administration and Transaction Costs

In addition to renewable energy supply costs, the cost of the Massachusetts RPS for new renewable resources was also assumed to be influenced by administration and transaction costs associated with procuring sufficient renewables to comply with the RPS, and with documenting and verifying compliance with the RPS. Massachusetts end-use customers were also assumed to face certain costs associated with DOER's administration of the RPS. Appendix A explains in detail our assumptions for the administration and transactions costs associated with the Massachusetts RPS for qualifying new renewable resources. In this section we briefly review the approach taken to develop these estimates and the final assumptions used in our analysis.

In developing preliminary estimates for these costs, we split the administrative and transactional requirements of the Massachusetts RPS into a number of specific categories. The cost estimate for each category was assumed to depend on the accounting and verification option selected by the DOER. The three accounting and verification options considered include: (1) contract-path tracking with restricted unbundling approach,[26] (2) a renewable energy credits approach applied only in Massachusetts, and (3) a full certificates approach applied to all generation sources on a regional basis. [27]

As detailed in the appendix, the administrative and transaction cost categories that we considered included:

- Program administrative costs
    - Ongoing DOER administrative costs
    - Start-up costs associated with RPS administration and development of REC or certificates registry

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[26] In a contract-path tracking system, title to attributes is assumed to be flow with title to energy. Each energy contract is identified at the generator and all power is tracked through to the final sale. As used here, title is assumed to be bundled with energy. However, where a wholesale or retail supplier makes multiple sales from a portfolio of energy with associated attributes, a discretionary allocation of attributes among these sales by the supplier, as well as transactions of energy and attributes through a renewable power exchange or similar trading hub are presumed to be recognized under the accounting system. In effect, this allows the temporary unbundling of energy and attributes and a subsequent re-bundling either within a portfolio or through a transaction hub, hence "restricted unbundling."

[27] After this analysis was completed, NEPOOL members voted on November 3, 2000 to pursue a region-wide certificates program called the Generation Information System Database. This is equivalent to option number three. While these costs are significantly less than a MA REC system, the final results of the analysis would not change significantly because transaction and administration costs are small compared to renewable generation costs.

  - Costs to operate a registry
- Supplier transaction and filing costs
  - Retail supplier transaction and filing costs
  - Wholesale transaction costs

We assumed that all administrative and transaction costs experienced by wholesale or retail suppliers in complying with the RPS requirements would ultimately be passed on to customers. We also assumed that program administrative costs would ultimately be passed on to renewable generators or retail suppliers, and ultimately passed through to end-users. Only incremental costs were included in the analysis, that is, those costs that the Massachusetts RPS was assumed to directly and incrementally impose on market participants and that we assumed would ultimately be passed on to end-use customers in Massachusetts. The estimates do not presume that administration and transaction costs will be shared with a Massachusetts requirement for existing renewables[28].

For some of the cost categories, we assumed that per-unit costs would decrease over time as transactional and administration efficiencies are gained. Our estimates, as described in detail in the Appendix, should be considered highly uncertain and preliminary. Under the REC system, we assume that such a system is only used in Massachusetts and is paid for by DOER and Massachusetts customers. If the REC registry were to be used by other states, its incremental cost to Massachusetts end-use customers could decline as fixed costs are spread over a larger base. Under a full, regional certificates model, we assume that the incremental cost associated with accounting and verifying the Massachusetts RPS is more modest since it is but one of many state policies that would rely on the system. In this instance, we assume that setup costs associated with a regional certificates program are essentially sunk and that the RPS program does not cause Massachusetts to absorb a greater share.

Table 11 shows the overall cost estimates that result from our aggregated detailed assumptions for each accounting and verification system for Massachusetts' RPS for new renewable resources.

[28] In the event of a requirement for existing renewables, fixed costs of procurement, compliance and administration would be spread over a greater number of units, resulting in lower average rate impacts per kWh of RPS requirement.

Table 11: Estimated Administration and Transaction Costs

Accounting System	Start-up Costs	Fixed Ongoing Costs	Variable Ongoing Costs
Contract Path with Restricted Unbundling	$200,000	$3,000,000/year	$1.5/MWh in 2003 decreasing to $0.5/MWh by 2012
Massachusetts RECs	$500,000	$1,975,000/year	$0.5/MWh in 2003 decreasing to $0.2/MWh by 2012
Full Certificates	$175,000	$840,000/year	$0.5/MWh in 2003 decreasing to $0.2/MWh by 2012

We assume that all start-up costs are passed on to Massachusetts's end-use customers in 2003 and that variable operating costs decrease linearly between 2003 and 2012. Applying these assumptions, and the aggregated cost estimates above, to the estimated demand for qualifying new renewable energy resources in Massachusetts needed to comply with the new renewables RPS, Table 12 provides overall administration and transaction cost estimates (per kWh of new renewables), by year and accounting method selected.

Table 12: MA RPS Administrative and Transaction Cost

¢/kWh of new renewables	2003	2006	2009	2012
Contract Path with Restricted Unbundling	0.95	0.48	0.32	0.16
MA REC	0.59	0.23	0.15	0.08
Certificates (NEPOOL)	0.17	0.09	0.06	0.04

Note that for all of the scenarios examined, we assumed that a Massachusetts REC system would be implemented for a variety of reasons. Currently, it is difficult to ascertain if and when the states with RPS requirements in NEPOOL would create a regional certificates program so this option was not considered further. Also, the REC system cost is estimated to be approximately half as much as a contract path with restricted unbundling and was therefore chosen as the base case option. Finally, we decided not to vary the administrative and transaction costs in the high and low cost of compliance scenarios due to the relatively small impact they have on the overall cost of compliance, as compared to the RGP.

2.7. Rate Impacts

2.7.1. Assumptions

Table 13 provides a summary of assumptions that we used to develop the rate impact estimates for the Base Case.

Table 13 Summary of Assumptions

Element	Assumption
Supply:	
• Wind production tax credit	Extended at 0.5 cent/kWh for 2001 - 2006
• Increased production at existing biomass plants	Increase in output over 1995 - 1997 is eligible as new, subject to emissions limits
• Biomass co-firing with coal	Would not trigger New Source Performance Standards
• Biomass emissions limit	1.5 - 2.0 lb/MWh NOx
• Biomass plant emissions	Carbon-neutral, due to sustainable biomass production
• LFG plant emissions	Carbon- and NOx-neutral when compared to flaring
• Project financing	17% carrying charge
• Imports	No restrictions on use of imports for RPS compliance
• Effect of SBC funds	Reduces marginal cost of supply by $3/MWh
• Effect of emission markets on RPS prices	All revenue requirement comes from sale of energy & attributes in electricity market (no reduction due to alternate revenue streams from sale of allowances, ERCs, etc.)
Demand for new renewables	Includes mandates: MA and CT RPS requirements and consumer willingness to pay
Accounting and verification	State-wide Renewable Energy Credits for base case
Retail Electricity Supplier compliance	Design features assure essentially 100% compliance

2.7.2. Results

The aggregate cost to Massachusetts's end-use customers for incremental renewable generation is estimated for each sample year as the product of: (1) the required quantity of renewable generation; and (2) the estimated renewable generation price plus per-unit administration and transaction costs. These total costs are summarized in Table 14 for each of the accounting and verification approaches evaluated. These costs are expected to increase substantially over time, as more renewables are required under the Act. In addition, part of the compliance cost increase is driven by an increase in the per-unit cost of incremental renewables being developed, reflecting the expectation that a rapid increase in renewable requirements under the Massachusetts and Connecticut RPS programs is likely to deplete the lower-cost renewable technologies and sites. The base case analysis indicates that the increase in renewables required and hence the shift to more costly technologies and sites is likely to more than offset the technological advance and economies of scale that are anticipated to drive down the cost of renewable technologies over time. The cost to customers also includes administration and transaction costs, which are expected to decline on a per-unit basis over time as they are spread over larger transaction volumes.

Table 14 Total Cost to MA End-use Customers

$ (million)	2003	2006	2009	2012
Contract Path with Restricted Unbundling	$15.8	$36.6	$61.8	$110.7
MA REC	$13.9	$33.1	$57.8	$107.2
Certificates	$11.8	$31.1	$55.5	$105.3

Table 15 translates the total costs from Table 14 into the average rate impact (in ¢/kWh) to all Massachusetts end-use customers by dividing the total cost over the projected retail sales to Massachusetts end-use customers[29]. If the average total bundled[30] retail rate in Massachusetts holds at approximately 9.0¢ per kilowatt-hour (in 2000$), the base case rate impacts would reflect a roughly 0.4 percent increase in the average retail rate in 2003, increasing to about 2.2 percent in 2012. To put these figures into perspective further, consider an average Massachusetts household whose average electricity use per year is approximately 6,000 kWh. The RPS increases their annual expenditure by $1.80 in 2003 (or 15 ¢/month on average), $3.60 in 2006 (30 ¢/mo. on ave.), $6.00 in 2009 (50 ¢/mo. on ave.) and $10.80 in 2012 (90 ¢/mo. on ave.), measured in today's dollars.

Table 15 Average Cost to MA End-use Customers, ¢/kWh

¢/kWh of retail sales ($2000)	2003	2006	2009	2012
Contract Path with Restricted Unbundling	0.03	0.07	0.11	0.18
MA REC	0.03	0.06	0.10	0.18
Certificates	0.02	0.06	0.10	0.18

[29] Excluding those customers of the fraction of Municipal Light Plants assumed to not open their territories to retail choice. See Section 2.3 for our assumptions about Municipal Light Plant participation.

[30] The bundled rate includes all services formerly provided by the monopoly utility, and today provided by the local distribution company (transmission, distribution, transition, and systems benefit charges) and the generation service supplier.

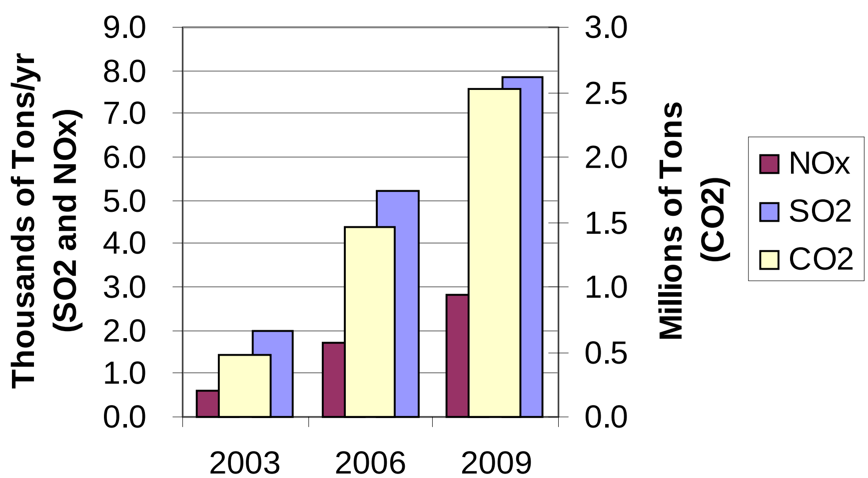
2.8. Displaced Air Emissions

Addition of renewables to the grid will lead to reduced output at marginal generating plants in New England and neighboring control areas. Today these marginal sources primarily oil and gas-fired steam plants[31]. We expect that the marginal generating sources will change significantly in the near future, as substantial amounts of newly constructed natural gas-fired combined cycle plants enter the market. These new plants will displace output from some of today's marginal sources, and will become an increasing fraction of the New England margin.

To estimate the air emissions that will be displaced by new renewable generating sources, we used regional dispatch simulation of the New England electricity market. This analysis tracked regional emissions of SO_2, NO_x, and CO_2 and from it, we were able to determine the marginal emissions that will be displaced by the Massachusetts RPS requirement.

Figure 11 illustrates the estimated regional air emissions that would be displaced by new renewables developed to meet the Massachusetts RPS.[32] The displaced emissions in this analysis come primarily from New England generating plants; we estimate that a small fraction of the reduction would come from generation in neighboring control areas.

Figure 11: Estimated Air Emissions Displaced by MA RPS



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[31] To the extent that renewables imports supplant imports currently associated with fossil generation, or more likely, undifferentiated energy, without increasing the total quantity of energy imported, the displaced air emissions impacting Massachusetts citizens may be overstated by assuming displacement of the New England marginal generating plants. However, to the extent that imports from new renewables are from upwind sources/facilities, the net benefit in terms of air pollutant emissions reductions may actually increase if the exporting region has a "dirtier" marginal emission rate than New England.

[32] The dispatch analysis of emission displacement was conducted through 2009. The estimated savings in 2012 would be approximately proportional to those for 2009, with the absolute tons increasing with the size of the RPS requirement.

While many of the eligible renewable resources have no air emissions, some renewable technologies have emissions that must be included in order to determine the *net* emissions displaced. We assumed that incremental SO_2 and CO_2[33] emissions for all renewables were negligible. NO_X emissions need to be considered, however. For landfill methane, we assumed that flaring was the default mode of operation and that combustion of the resulting methane would have approximately the same NO_X emissions whether flared or converted to electricity. Thus, net NO_X emissions associated with electric generation are assumed at zero.[34] For biomass technologies, we assumed that they would on average use a low-$NO_{X,}$ sustainable supply of biomass and that they would meet the proposed 1.5 to 2.0 lb./MWh NO_X emission rate limit (on average at 1.75 lb./MWh).

The net emissions associated with RPS-driven generation were calculated by subtracting out the total marginal emissions that are projected to be displaced from NEPOOL, and by adding in the emissions associated with renewables generation. Figure 12 presents the estimated net reduction in air emissions for each snapshot year, assuming that these emissions reductions are permanent.

As discussed in Section 1.2.3, SO_2 and NO_X are presently regulated under "cap and trade" programs in which the total allowed emissions are fixed on a national and regional basis, respectively. In addition, there is potential for the development of an international market in CO_2 offsets. We therefore expect that some portion of the emissions displacement estimated here may ultimately be eroded, to the extent that SO_2 allowances, NO_x emission reduction credits (ERCs) or CO_2 offsets are created and sold to parties that increase their emissions accordingly. For that portion of reductions for which allowances or ERCs are resold, the effect will ultimately serve to reduce the regional cost of emission compliance (by reducing the need for other control measures), rather than reducing the absolute amount of regional emissions. The magnitude of the potential for cap and trade programs to erode the projected emission reductions is unclear without further study of the extent to which allowances or ERCs would be conferred upon the developers of new renewable generation. If DOER wished to ensure that new renewable generation will produce emission reductions, it would be necessary to require that qualifying renewable generators retire any tradable allowances or ERCs awarded as a result of the installation. However, it does not appear that the Act explicitly identified this objective or assigned the DOER the authority required to implement it. Therefore DOER's approach is that the capped emission levels are not necessarily affected by existence of the RPS. However, to the extent that a generator taps additional revenue streams by selling allowances, ERCs or offsets,

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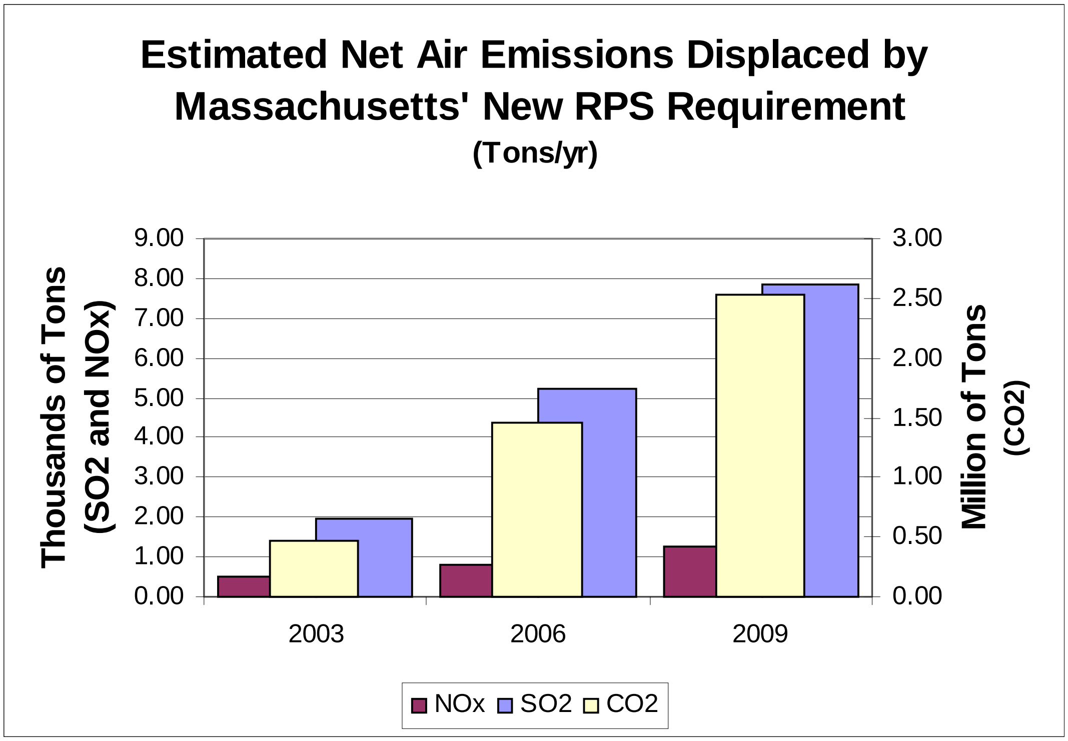
[33] CO_2 emissions for biomass technologies are considered effectively zero. We assumed that all carbon dioxide emitted due to biomass combustion was captured by the biomass during its growth cycle so that, in effect, no additional carbon dioxide is added to the atmosphere. And although combustion of landfill gas yields CO_2 emissions, when compared to the default assumption of flaring methane, emissions are effectively the same.

[34] Flaring landfill methane uses a lower temperature for combustion, which yields less NO_X emissions than combustion for electric generation. On the other hand, generators are subject to control regulations on a state and federal level, which will tend to limit emission rates. We assumed that these factors offset each other, so that the net change in NO_X emissions from electric generation burning landfill gas is approximately zero. This assumption is likely to slightly overstate NO_x emission reductions. However, as we assume that the conversion technology for landfill gas will evolve towards low- NO_x -emitting micro-turbines and ultimately fuels cells which create no thermal NO_x, decreasing any such overstatement over time.

the revenue required from sale of energy and attributes is reduced accordingly. Therefore, to the extent that emission reductions fall short of those predicted, we would expect a corresponding decrease in the cost of renewables to retail suppliers, the compliance costs of those suppliers, and ultimately to the cost impact of the RPS to electricity customers in the Commonwealth.

Figure 12: Estimated NET Air Emissions Displaced by MA RPS



2.9. Effect of New Renewables on Natural Gas Market

The new renewable generation stimulated by the Massachusetts RPS will, in the short run, displace production from marginal generating units in New England. These marginal sources are primarily steam and combined cycle units burning natural gas, and steam units burning residual oil or natural gas. In the long term, the displaced generation will be increasingly from new combined cycle units that burn natural gas. It is therefore possible that by reducing the quantities of natural gas and oil that are required for electric generation in New England, the new renewables will decrease the market clearing prices (and therefore, the cost to consumers) for those fuels.

Using some simplified assumptions, we took a quick look at the potential impact on natural gas supply. The new renewable requirement in Massachusetts is estimated at about 518,000 MWh in 2003, increasing to about 4.5 million MWh in 2012. This is equivalent to about 70 MW of baseload generating capacity (producing at an 85 percent capacity factor) in 2003, increasing to about 600 MW by 2012. Assuming that the displaced generation were from new natural gas-fired combined cycle plants with an average heat rate of 6,700 BTU/kWh, the 2012 RPS generation would reduce the burning of natural gas in the region by about 29,000 million cubic feet per year. For context, the U.S. Energy Information Agency reports that in 1999, total natural gas consumption in New England (including all end-uses) amounted to about 590,000 million cubic feet per year.[35] Nationwide, in 1998 only 17.2 percent of total natural gas consumption is used in the electric sector and by 2020, it is projected to increase to approximately 30 percent by 2020.[36] However, New England's natural gas usage (both for electric generation and other sources) is significantly behind the rest of the country and is expected to increase significantly over time. Therefore, it is reasonable to conclude that by 2012, RPS-induced generation will probably reduce New England's natural gas consumption by at least several percent.

The specific impacts of such a reduction in natural gas consumption are difficult to quantify, particularly for the later years in which the RPS requirement has grown to a substantial size. For example, the RPS could reduce the cost of upgrading gas pipelines that are needed to serve the region reliably. It is also possible that a reduction in natural gas consumption would lower spot and/or forward market prices of natural gas in New England, thereby reducing the cost to supply gas to a range of retail customers.

Some industry analysts have examined the potential impacts from increased renewable electricity generation. The 1996 report by the New England Governors' Conference examined the case where half of all new generation capacity was from renewable resources instead of it all being fueled by natural gas (their base case assumption). This new renewable case predicts that the decrease in natural gas demand due to new renewable generation could decrease electricity prices by approximately one to two percent.[37] In another study, the U.S. Energy Information Administration examined the potential impact of the Administration's aggressive national RPS proposal from the Comprehensive Electricity Competition Act, submitted to Congress on April 15, 1999. This report predicts that for a RPS without a cap and without a sunset provision, electricity prices would be 3.2 percent above reference case prices in 2010 and 1.4 percent above reference case prices in 2020.[38] EIA's projection of electricity costs implicitly includes the resulting cost decrease due to reduced natural gas use in power plants. Projected costs would have been higher were it not for this effect. Isolating the magnitude of this impact requires further analysis beyond the scope if this study. In addition, end-use customers could realize additional cost savings in other sectors if overall natural gas prices decrease due to reduced use in the electric sector.

Quantifying these effects, and their probabilities, is beyond the scope of this Massachusetts RPS cost and impact analysis. This may be a suitable topic for further research.

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[35] Energy Information Administration, *Historical Natural Gas Annual 1930-1999*, U. S. Department of Energy DOE/EIA-E-0110(99), October 2000, Table 15 page 189.

[36] Energy Information Administration, *Annual Energy Outlook 2000*, U. S. Department of Energy DOE/EIA-383(2000), December 1999, pages 23-24.

[37] New England Governor's Conference, Inc., *Assessing New England's Energy Future*, December 11, 1996.

[38] Energy Information Administration, *Annual Energy Outlook 2000*, U. S. Department of Energy DOE/EIA-383(2000), December 1999, page 19.

2.10. High and Low Compliance Cost Cases

Testing the sensitivity of assumptions helps us understand, and to some degree bound the range of potential results. Due to the complex nature of the analysis, the large number of variables involved, and the uncertainty with making long-term forecasts involving many variables undergoing rapid change, we felt it most useful to define two primary sensitivities to the base case: (1) a high compliance cost case and (2) a low compliance cost case. For these cases we adjusted each of several input assumptions simultaneously, in order to create relatively high and low cost outlooks for the incremental cost of new renewable power. The high and low cost cases likely encompass the majority of possible actual outcomes, but they do not represent the upper and lower bounds of potential outcomes.

Table 16 Assumptions for High and Low Compliance Cost Cases

		High cost case	Base case	Low cost case
Supply-side	1)Technology-specific cost per kWh	2003: +10% 2006: +10% 2009: +10% 2012: +10%	As estimated from various sources.	2003: -10% 2006: -10% 2009: -10% 2012: -10%
	2) Technology – specific available generation	'03 '12 LFG: -5% -15% Bio: -10% 15% Wind*: -10% -20%	As estimated from various sources.	'03 '12 LFG: +5% +15% Bio: +10% +15% Wind*:+10% +20%
	3) Impact of renewables SBC fund expenditures	$1/MWh reduction to RGP	$3/MWh reduction to RGP	$3/MWh reduction to RGP in 2003, $4/MWh in 2006, $5/MWh thereafter
Demand-side	1) RPS demand	Assume VT has a requirement like MA; NY requirement is half of MA.**	CT & MA only	CT & MA only
	2) Retail sales growth	CELT + 0.5%/year	At CELT projected historical growth	CELT – 0.5%/year
	3) Non-RPS green demand (as % of resid.)	6.25% in 5 years 18.75% in 20 years	2.5% in 3 years 10% in 20 years	2.5% in 5 years, remains at 2.5%

* For wind, we assume changes in the federal production tax credit as well. In the base case, we assumed it was extended at only 0.5¢/kWh (2000$) through 2006. In the high-cost case, we assumed that PTC was not extended; in the low-cost case, we assumed that it was extended at its current level of about 1.8¢/kwh ($2000) through 2006.

** Due to New York's proximity and access to several states and Canadian provinces, we assumed that if New York were to implement a RPS requirement, two thirds of the required new renewable production could be obtained from outside NY and New Eng. – that is, from areas outside the scope of this analysis.

Table 16 gives a summary overview of the variables that were adjusted, relative to the base case, to develop the high and low compliance cost cases. Some of the key assumptions are explained in more detail later in this chapter.

To test the potential range of compliance costs, the high and low compliance cost cases focus on the range of renewable generation costs. Administration and transaction costs, which we expect will make up a small fraction of total compliance costs, were not varied. On the supply side, we varied the amount of generation available from each renewable technology, and the all-in cost of generation from each technology. On the demand side, we tested the effects of alternative RPS requirements, rates of electricity demand growth, and consumer-driven green demand.

2.10.1. Supply Side Variations

Because the estimated cost of power from new renewables depends on a large number of assumptions (particularly capital costs, annual carrying charge rates and O&M costs), we tested a considerable range of per kWh costs around the base case values. To derive renewable supply costs for the high and low compliance cost cases, we varied the cost per kWh for each technology, by plus or minus ten percent in all years of the analysis. In addition, for wind, we assume changes in the federal production tax credit as well. In the high-cost case, we assumed that PTC was not extended; in the low-cost case, we assumed that it was extended through 2006.

We expect that the amount of generation available could also vary significantly, and could vary more strongly for particular technologies. In particular, the size of the wind resource will depend strongly on a large number of site-specific issues, and on the success and timing of siting efforts. Table 17 presents the technology-specific ranges that were used to estimate the amount of generation available from the largest renewable technologies. All percentages are relative to the base case assumptions that are summarized in Section 2.4 and Appendix B.

Table 17: Resource Quantities for High and Low Compliance Cost Cases

	2003	2006	2009	2012
Landfill gas	±5%	±8.3%	±11.7%	±15%
Biomass	±10%	±11.7%	±13.3%	±15%
Fuel Cells*	±10%	±11.7%	±13.3%	±15%
Wind	±10%	±13.3%	±16.7%	±20%

* Fuel cells using fossil fuel only. This source is only eligible in Connecticut and assumed to comprise a maximum of 25 percent of their requirement.

2.10.2. Demand Side Variations

Demand for new renewable energy generation could be impacted by (1) additional RPS requirements; (2) annual growth rates in retail sales; and (3) changes in non-RPS demand for renewables.

Currently, only Connecticut and Massachusetts have a RPS requirement for new renewable energy generation. When considering a high cost scenario, we decided to include potential demand from Vermont and New York, since RPS requirements have been proposed, but not yet adopted, in both states. Additional demand will put additional pressure on the available resources and could drive up the cost to consumers, perhaps significantly. We assumed that both come on-line by the end of 2003 and that the Vermont standard is equal in percentage to the Massachusetts requirement, whereas the New York requirement is half of the percentage requirement of Massachusetts. We assumed the RPS demand would not vary between the base and low compliance cost case.

Next, we considered changes in retail sales growth. In general, since the RPS requirements are stated as a percentage of total sales, the greater the demand for electricity in New England (particularly in Massachusetts and Connecticut), the higher the cost of renewable supply will be, since more costly supply sources will be required. Predictions for retail sales growth are based on historical growth rates, but shifts in the economy's growth rate, the number of businesses entering or leaving and area and shifts in population can significantly alter retail sales growth for electricity. To reflect some of these possibilities, we assumed that retail sales grow at the CELT forecast growth rate for the base case. For the high cost case we increased the growth rate at 0.5 percent per year relative to the base case, and for the low cost case decreased the base case growth rate by 0.5 percent per year.

Finally, we incorporated sensitivities around our non-RPS, or green market-driven demand assumptions. The base case percentages are stated for ease of calculation as an equivalent percentage of residential demand. For the high cost case, we assumed there was a combination of more demand and greater customer participation in retail shopping, which could lead to the equivalent of 4.4 percent of residential demand in year 5 and 18.8 percent of residential demand in year 20. Conversely, lower penetration of green marketing products and smaller customer participation in retail shopping was assumed to result in 2.5 percent of residential demand in year 5 coming from new renewables, which then flattens out to remain at 2.5 percent.

2.10.3. Results

Figure 13 presents the estimated total RPS premium over the term of the analysis for the Base, High Compliance Cost, and Low Compliance Cost cases. Based on the projected RGP results, and including administration and transaction costs, Figure 14 presents the estimated rate impacts of the RPS under the Base, High Compliance Cost, and Low Compliance Cost cases.

Figure 13 Renewable Generation Premium Above Wholesale Market Price

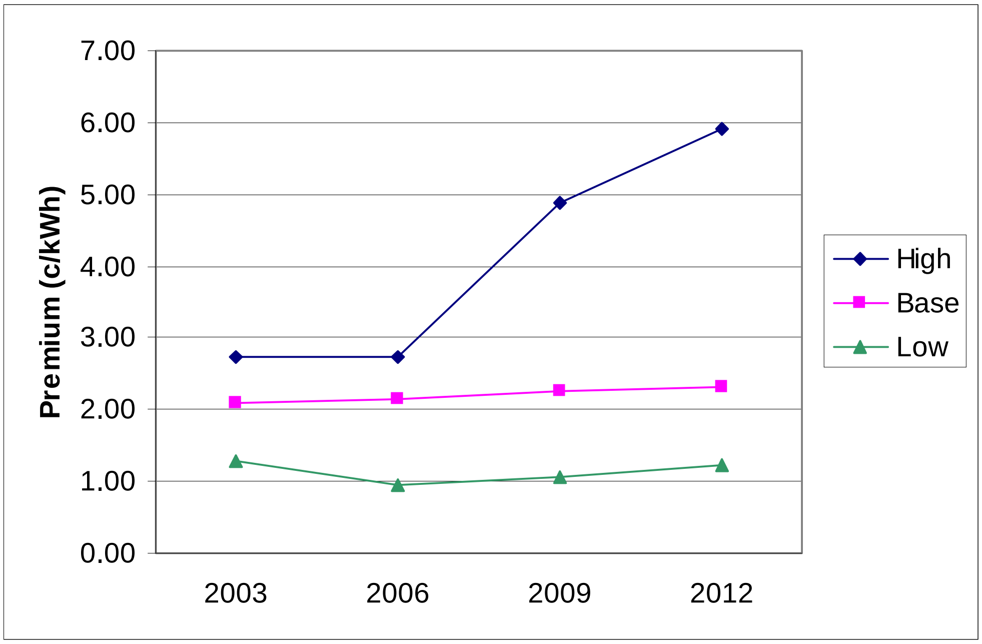
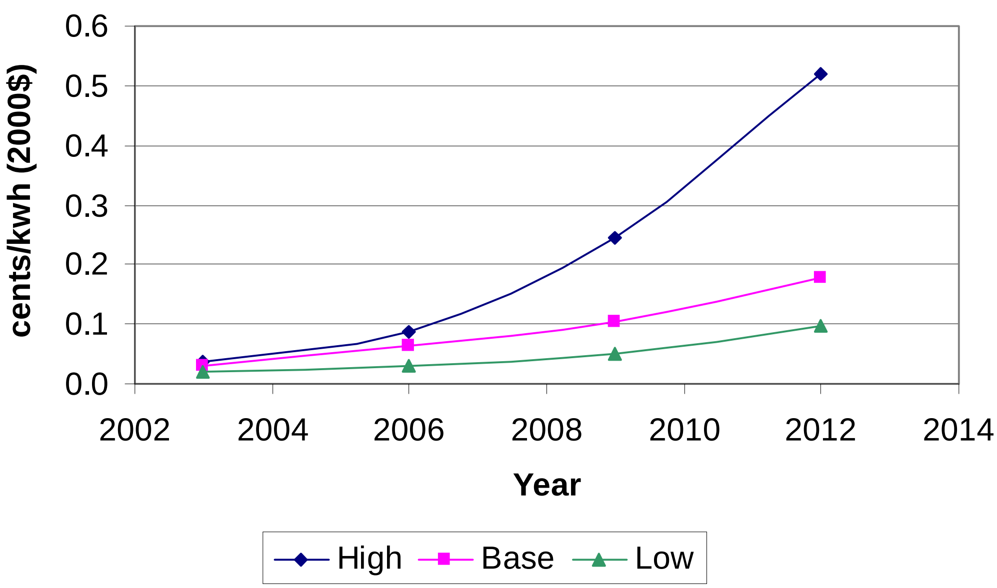


Figure 14: New RPS Requirement - Range of Rate Impacts



The following are key observations based on the results High and Low Compliance Cost Cases:

- The wide range of results reflects our expectation that actual costs and volumes for renewable technologies could vary substantially around our estimates.

- The asymmetrical appearance of the high and low cases can be explained by the shape of the supply curves and the point at which the demand forecast intersects with these curves. In particular, while the difference between high, base and low cases is small in the early years due to a shallow slope to the supply curve, the supply and demand intersect at a steeper part of the supply curve in the high case than in low case in later years. This reflects the possibility that eligible resources may be scarce in combination with higher demand, so that higher-cost renewables will called upon in later years under the high demand case.
- The High Compliance Cost Case results are driven not only by higher assumed costs for renewable technologies, but also by the assumed decrease in renewable resource depth and the assumed introduction of additional demand through a New York RPS and higher consumer-driven green demand. Variations in the actual *volumes* of demand and available supply may strongly affect the actual RPS compliance costs for Massachusetts, as different resources may set the clearing price.

We feel that our forecast is fairly conservative and that we incorporated reasonable supply and demand assumptions for new renewables and future market conditions. Table 18 compares those factors that could cause the projected cost of compliance with the MA RPS to be conservative, against those that could cause them to be aggressive. In addition to there being more reasons for the analysis to be considered conservative, the conservative factors seem more likely to materialize than the optimistic ones given current market conditions.

Table 18 The Base Case Analysis: Conservative and Optimistic Factors

Factors that could cause the projected base case RPS rate impact to be CONSERVATIVE	Factors that could cause the projected base case RPS rate impact to be OPTIMISTIC
CT RPS does not (currently) apply to standard offer, therefore, renewables demand in 2003 (standard offer ends 2004) likely to be less, reducing RGP in all three cases for 2003.	**Biomass Co-firing.** The role of biomass co-firing could be restricted if plants cannot co-fire without triggering New Source Performance Standards. This impact would make the supply curve steeper and increase prices in all cases.
Allowances, Offsets and ERCs. If renewable generators are able to generate supplemental revenue streams by selling off allowances, offsets or ERCs, the revenue required from the RPS market will be reduced. This effect would lower the rate impact (see Figure 13) for all three cases throughout the analysis period.	**Compatibility of Neighboring Regions.** Bordering regions in which eligible renewables are located are assumed to have "compatible information systems" allowing imports to qualify. If information systems are not deemed comparable, or imports are otherwise restricted (NY regulators may not want wind sold outside of state), eligible supply could be curtailed increasing costs in all cases.

Factors that could cause the projected base case RPS rate impact to be CONSERVATIVE	Factors that could cause the projected base case RPS rate impact to be OPTIMISTIC
ISO-NE certificates system would result in lower incremental transaction costs, consistent with Low Compliance Cost Scenario.	**Fossil fuel prices** ultimately plummet below original forecast, causing wholesale electric market prices to significantly decrease (as noted in the *conservative* column, prices currently exceed the forecast substantially, suggesting this outcome is less likely than the converse). The cost premium for renewables would increase, increasing rate impacts in all cases.
Fossil Fuel Cost Forecast. The current costs of fossil fuels, and the resulting commodity market price of electricity in the region, exceeds the long-term forecast used to generate the RGP and rate impact (substantially in the near term). If these commodity fuel and energy prices continue to exceed the forecast, the cost premium for renewables will be lower, and hence the rate impact will be reduced. This effect would lower the rate impact (see Figure 13) for all three cases, at least in the earlier years and perhaps throughout the analysis period.	**Project Financing.** We have assumed that projects can be financed on commercial terms. Today there is little evidence that the market is ready to finance plants on a merchant basis due to lack of regulatory certainty, while retailers and wholesalers appear unwilling to offer term commitments necessary for project financing due to perceived risks. The result may be increased costs of financing to reflect shorter-term commitments and greater revenue risk beyond the level accounted for in the analysis, or reduced availability of resources due to supplier inaction rather than lack of resource potential. This effect would increase the rate impact for all three cases.
Wind Energy Costs. Recent data suggests that the busbar cost of wind may be declining faster than projected. In addition to NREL projections, several projects under development considered in building the supply curve have been revising cost figures downward, and recent turbine procurement for projects under development have resulted in lower-than-expected capital costs. As wind is often found in the portion of the supply curve that sets the RCG, lower wind costs would reduce the RPS rate impact. This would shift the rate impact towards, or below, the low case.	**Market rules** may impose scheduling and regulation penalties on intermittent generation that increases the effective cost to the market. This could increase wind costs in particular by up to 0.1-0.2 cents/kWh, resulting in a small increase to the RGP and RPS rate impact in all three cases, to the extent wind is (and would remain) the marginal resource in any given year.
Wind Power Development Trends. Recent information suggests considerably greater amounts of wind power in the development pipeline than assumed in developing supply curves. This includes data from recent NYSERDA wind prospecting funding as well as increased capacity & funding of off-shore plans. Additional wind would flatten the supply curve, reducing the RGP and rate impact particularly in later years of the analysis. This would push the rate impact towards the low case, particularly in later years of the analysis.	**Congestion Management System.** Wind projects in New England are likely to be located in regions with relatively low transmission congestion. If a congestion management system is implemented by ISO-NE, then wind generators will receive somewhat lower spot market prices for power. Thus, the wind generator would require a higher renewable generation premium to recover capital and operating costs.

Factors that could cause the projected base case RPS rate impact to be CONSERVATIVE	Factors that could cause the projected base case RPS rate impact to be OPTIMISTIC
Biomass Fuel Costs. If biomass plants are able to procure eligible fuel on a delivered basis for a lower cost than forecast, supply costs may be lower (if biomass is marginal fuel or displaces other sources) and rate impacts would decrease in all cases.	
Natural Gas Supply. Renewables for the MA RPS are expected to displace significant natural gas use in New England. Potentially, this offset could decrease regional natural gas expenditures.	

2.11. Other Factors that Could Affect the Renewable Generation Premium

The high and low compliance cost cases examined in Section 2.9 do not address all possible factors that could affect the actual RGP. In this section we discuss some of these additional factors qualitatively and make suggestions for further quantitative analysis. Also, section 4.4 discusses the potential impact of state-system benefits charge funds such as the Massachusetts Renewable Energy Trust.

2.11.1. Analysis of Potential Alternative RGP Outcomes

As discussed above, the sensitivity cases incorporate combinations of assumptions (e.g., higher consumer-driven green demand, significantly higher renewable costs) that are reasonable on their own but may not represent realistic combinations. As a topic for further study, DOER may wish to examine the bounds of potential RGP outcomes in a more comprehensive manner, addressing the interrelationships among the driving variable.

2.11.2. Effect of Wholesale Electricity Prices on Renewable Generation Premium

The estimated Renewable Generation Premium reflects the difference between (1) the all-in cost of power from various renewable technologies; and (2) the value of the output from those technologies in the regional wholesale electricity market, without accounting for any renewable attributes. The cost of power from most renewables is not driven by the same factors that drive wholesale market prices. Actual RGPs (and most of the RPS compliance cost) will therefore tend to vary inversely, on essentially a one-for-one basis, with prevailing wholesale electricity market prices. The higher wholesale market prices (or price expectations) that result, the lower premium renewable projects will need in order to be viable investments. The base, high, low scenarios of RGP, which are described in Section 2.9, were developed by varying the supply curve (i.e., the amounts available at various price levels) for new renewables. The same outlook for wholesale electricity prices was used in each RGP scenario. This electricity price forecast reflects a range of input assumptions that were developed in 1999 using a "base case" approach.

In actual practice, wholesale electricity prices (and the outlook for those prices going forward) will vary considerably over time. Key drivers of electricity prices in the northeast U.S. will be fossil fuel prices (particularly the delivered prices of natural gas and residual oil) and the amount of new generating capacity that enters the market. Changes in the outlook for wholesale power prices essentially change the outlook for RGP on a one-for-one basis. The higher the price for generic wholesale power, the lower the RGP.

During 2000, short-term fossil fuel prices have risen substantially above those assumed in the 1999 electricity price forecast. For example, recent prices of futures contracts for natural gas at Henry Hub, Louisiana for 2001 have averaged about $4.60/mmBTU, compared to an assumption of about $3.50/mmBTU in the electricity price forecast. Similarly, recent futures contract prices for crude oil at New York Harbor for 2001 have exceeded $30 per barrel, compared to an assumption of about $18/barrel in the 1999 electricity price forecast. These fossil fuel price increases, along with other market factors, have significantly increased New England spot market electricity prices during 2000, and have increased the "forward" prices at which power for 2001 delivery is being traded. While forward market prices have been notoriously poor predictors of future prices, the implication is significant. We estimate that if electricity market prices in 2003 were to turn out as suggested by recent forward prices, new renewables could be delivered to market at prices approximately equal to the prevailing wholesale price. The estimated RGP would essentially be zero.[39]

Whether the recent electricity price increases will persist over time is, of course, unknown. The DOE long term fuel price forecast used in the electricity price forecast was developed using estimates of future demand, reserves, and production costs; these would seemingly not be affected by changes in short term market conditions. Similarly, it is important to keep in mind that approximately 4,500 MW of gas-fired merchant generating capacity is presently under construction in New England, and is expected to come online during 2000 and 2001. This substantial new capacity can be expected to put downward pressure on average electricity prices and on price volatility. It is not clear to what degree forward electricity prices reflect these effects.

A comprehensive analysis of future electricity prices is beyond the scope of the current analysis. Near term electricity price expectations clearly exceed those assumed in the RGP analysis, indicating that for the first snapshot year of 2003 the RGP is more likely to end up in the low end of the range estimated in this report. The longer-term outlook is more uncertain, and it will depend strongly on natural gas prices. If natural gas prices were to remain above levels in the 1999 forecast, the RGP would tend to be lower than shown throughout this analysis.

A logical topic for further quantitative analysis is the extent to which RGPs will vary based on plausible alternative wholesale electricity prices. The combined effects of renewable cost/depth and wholesale electricity prices would produce a somewhat wider range of potential RGPs than shown here.

[39] This analysis assumes that the RGP will equal the difference between: (a) "all-in" cost of production from new renewable generators; and (b) the prevailing price of generic wholesale power. If these two quantities are equal, the estimated RGP is zero. It is conceivable that if renewable generators were able to produce power at the prevailing wholesale price, they might still be able to command some premium.

2.11.3. Effect of Renewables on Regional Electricity and Gas Supply

In this study, the incremental cost of renewable generation above was derived for each year as the product of the RGP and the required amount of renewables. We did not attempt to estimate the extent to which the introduction of new renewable supply sources will have the additional (and offsetting) effect of reducing ratepayer costs by reducing the prevailing prices for wholesale electricity or natural gas in the region.

Specifically, as shown in Table 1, we estimate that the renewables stimulated by the Massachusetts RPS will amount to the equivalent of 70 MW of baseload power in 2003, and about 600 MW in 2012. These amounts, particularly toward the end of our study period, are not insignificant relative to the NEPOOL load, and are larger than many thermal generating units. A resource at the large end of this range would, all else being equal, be expected to lower the market-clearing price for electricity by a noticeable amount on an annual basis. Alternatively, the new renewables might displace an equivalent amount of new merchant combined cycle capacity. In that instance, the clearing price for electricity would essentially be unaffected in the long term, but significantly less natural gas would be consumed for electric generation and the regional price for gas could be affected.[40]

To the extent that the new renewables do place a downward influence on either gas or (particularly) electricity prices in this fashion, that influence will serve to offset some of the effect of the Massachusetts RPS on customers' retail rates and bills as estimated in this analysis. While we do not expect that this effect could offset nearly all of the costs, we note that the effect could be significant because it would theoretically affect all consumption, not only the renewable portion. We therefore believe that this topic would be appropriate for further analysis by DOER.

2.11.4. Offshore Wind

The base case analysis assumes that about 2,200 MW of wind projects could become available, if needed, by 2012. This resource is assumed to consist primarily of land-based wind projects in New England and neighboring regions, and up to 300 MW of offshore wind.

While there are no commercial offshore wind projects at this time, offshore wind resources offer several advantages relative to land-based systems. The advantages include higher and steadier wind speeds (resulting in higher potential capacity factors and lower production cost per kWh), and the prospect for easier permitting. Some commenters and studies suggest that the technical potential for offshore wind available to the Northeast U.S. is orders of magnitude larger than assumed in the base case analysis, and in fact larger than the entire regional renewable requirement. Such a large resource would, if demonstrated to be viable, greatly extend the renewable supply curve. Offshore wind would become central to the analysis in 2009 and 2012 when RPS-driven demand in the region becomes very substantial, and it could place an effective

[40] In 1996 the Regional Energy Assessment Project (REAP) conducted an energy analysis for New England. REAP examined a scenario in which renewables accounted for 50% of new electric generation construction in New England. The analysis projects a decrease in demand for natural gas and a corresponding slight decrease in electricity prices. (New England Governor's Conference, Inc., *Assessing New England's Energy Future*, December 11, 1996).

cap on compliance costs in a high-cost environment where the amounts and costs of power from other renewables turn out less favorably than expected.

Because the offshore wind resource is essentially unproven and its potential contribution to the regional supply is extremely large, a valuable topic for future study would be a more detailed review of its likely cost, depth, and timing.

2.11.5. Price of Biomass Fuel Supply

Several biomass technologies play a significant role in the supply curves for new renewables and in the base case analysis, are forecast to supply a considerable portion of renewable demand in the long term. The price of biomass fuel will depend in part on the total volume of fuel required in the region, and could vary significantly by location.

This analysis assumes that all new biomass projects will be able to purchase a sustainable wood fuel supply at a price of $3.50/mmBTU ($2000). This price is lower than the long term price estimated by the Energy Information Administration (EIA)[41] for large volumes of sustainable biomass harvest in New England and neighboring markets, but we understand that it is higher than the historical fuel cost at most existing New England biomass plants. Because regional wholesale electricity prices are not significantly correlated with biomass fuel prices, the actual premium required for biomass-based technologies will vary directly with actual with the price(s) for biomass fuel. Appropriate topics for further study therefore include:

- A more comprehensive analysis of the base case outlook for biomass fuel prices;
- The extent to which biomass fuel prices will increase with the total volume of biomass generation;
- The extent to which biomass fuel prices are likely to vary across New England and neighboring markets;
- Sensitivity analysis to illustrate the extent to which RGPs and RPS impacts would change under alternative biomass fuel price outcomes.

2.11.6. Effect of RPS-Driven Generation on Allowance Prices

Because new renewable generation (with zero or low air emissions) stimulated by the Massachusetts RPS will displace output from higher-emitting fossil-fired plants in the region, it is possible that one of its effects would be to lower the clearing price of air emission allowances. We considered this possibility for SO_2 allowances (which are traded on a national basis) and for NO_x allowances (which are traded on a regional basis across the eastern U.S.). For several reasons, we conclude that the MA RPS is unlikely to perceptibly impact the allowance clearing prices.

First, the new renewable generation that will be stimulated by the Massachusetts RPS is equivalent to about 70 MW of baseload power in 2003, increasing to about 600 MW by 2012. These amounts are very significant relative to the state's electricity requirements, but very small

[41] Preliminary draft information updating biomass cost and resource used in AEO 2000 that will be used in AEO 2001. Conversation with Zia Haq, Energy Information Administration, U.S. Department of Energy, June 12, 2000.

relative to the SO2 and NOx allowance markets. For context, the SO_2 and NO_x markets encompass several hundred thousand MW of coal-fired generating plants, and similar amounts of gas- and oil-fired plants. In 2003, the emissions displaced by the MA RPS generation would be imperceptible in the marketplace. Even in 2012, the MA RPS generation would be relatively small compared to variations in the factors (e.g., electricity demand, generating unit performance, merchant plant development) that drive variations in the SO_2 and NO_x markets. For example, the total fossil-fired generation displaced by the Massachusetts RPS in 2012 would only amount to less than one tenth of one percent of electricity demand growth in the relevant market region of over 500,000 MW.

Second, the impact of MA RPS generation on allowance markets will be limited by the fact that the New England power plants it displaces tend to be cleaner than the fossil-fired generation in the rest of the eastern U.S. This is due in part to the New England fuel mix, as well as to the existing levels of emission controls. In addition, because large amounts of cleaner gas-fired merchant plants are presently under construction and will reach the market before 2003, we expect marginal emission rates in the region to decline further.

These factors indicate that while the MA RPS generation has the potential to noticeably reduce the air emission profile of the Massachusetts electricity supply, it will not affect the clearing price for SO_2 and NO_x allowances to any significant degree.

2.11.7. Additional Factors

As discussed in section 2.5, the estimated base case renewable generation premium increases slightly from 2003 to 2012. To the extent that such projects sell their attributes under long term contracts at prices below the price required by the highest-cost entrant, the average costs for retailers to acquire their RPS requirements could turn out lower than the RGP. Thus, the total cost to Massachusetts end-use customers would be reduced.

Also, RPS will increase the diversity of electric generation sources that serve Massachusetts end-use customers, especially in the later years of the study period. The potential for greater diversity's reduction of overall generation portfolio risk to lead to lower costs for RPS is topic to consider for further study.[42]

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[42] See Awerbuch, Shimon, *Getting it Right: The Real Cost Impacts of a Renewables Portfolio Standard*, Public Utilities Fortnightly, February 15, 2000.

3. BASELINE REQUIREMENTS ANALYSIS

3.1. Objectives

As discussed above, the Act requires that retail suppliers of Massachusetts end-users derive specific fractions of their supplies from certain eligible *new renewables*; all such projects must have come online after December 31, 1997. In addition, the Act instructs DOER to determine the fraction of Massachusetts' historical supply that was derived from a group that we will refer to as *existing renewables*. Existing renewable projects include those that were commercial before December 31, 1997 and they include several technologies (most importantly hydroelectric and municipal solid waste) that are not eligible as new renewables. The Act does not clearly specify whether a requirement to maintain the historical level of renewable resources serving Massachusetts end-users, comparable to that for new renewables, should be implemented. This section of the cost/impact analysis estimates the potential supply and demand for existing renewables, to inform DOER's determination as to whether implementing a standard for existing renewables would be meaningful. In this context, we define a meaningful impact to be one in which the presence of a Massachusetts RPS requirement to maintain the historical level of renewable resources leads to additional revenue available to renewable generators above the commodity market value of their production.

3.2. Methods and Assumptions

We estimated the demand and supply for existing renewable generation available to New England over the next 20 years. Our primary assumptions and methods are as follows.[43]

The largest components of *demand for existing renewables* are the RPS requirements that have been established in Maine and Connecticut, along with the Massachusetts RPS whose design is the focus of this analysis. Each state defines a different set of eligible renewables, but there is sufficient overlap across the state requirements (e.g., municipal solid waste and at least a subset of hydro are eligible in all three states) such that renewables can flow to where they are eligible, displacing those eligible in other states. The demand for existing renewables was therefore estimated on a regional basis, including the three state RPS programs plus an estimate of consumer-driven demand for green electricity products that contain existing renewables.

The *supply of existing renewables* will depend on future wholesale electricity prices; the condition of equipment and expected going-forward O&M costs at existing renewable plants; the commercial decisions of market participants (e.g., whether to sell energy in New England or elsewhere); and the magnitude (if any) of a market premium for existing renewables. Using a range of sources, we constructed an informed set of assumptions for high and low availability scenarios. The highlights of the high and low supply cases are as follows:

- The low supply assumptions are intended to represent a scenario in which there is not a substantial market premium for existing renewables. Imports from neighboring regions are

[43] An additional discussion of assumptions and methods was also presented in a May 12, 2000 letter from La Capra Associates to the RPS Advisory Group.

assumed to be less than historical levels. Existing biomass and municipal solid waste facilities presently selling under long-term power sale agreements are assumed to experience retirement rates of between 25 and 75 percent after those agreements expire. 70 percent of existing small hydro projects are assumed to remain on-line.

- The high supply assumptions reflect a scenario in which more renewables are available to the New England market, whether due to exogenous forces or to a significant renewable market premium. This case assumes that imports from neighboring regions will be available at levels above those experienced in the past several years and that existing biomass and municipal solid waste plants will experience retirement rates of 25 percent or less. Small hydro is assumed to experience little attrition, with approximately 90 percent of existing generation remaining on-line. The potential for additional imports reflects the fact that there are substantial volumes of existing renewables (primarily hydro) in New York, Quebec, and New Brunswick[44]. If a significant renewable energy premium were to materialize in New England, these significant volumes would face only limited cost barriers (e.g., transmission charges and losses) to sell into New England. Of course, the amount of renewables available to New England would be limited by transmission constraints across neighboring systems (particularly New York) and by the transmission interfaces into New England.

- The analysis assumes that there would be no size restrictions on hydropower eligibility.

3.3. Results

Figure 15 illustrates the estimated regional supply/demand balance over time, assuming the high and low supply cases. Note that two lines represent demand: one reflecting only RPS-driven demand and one including an estimate of consumer-driven green demand in the region.

Highlights of the results are as follows:

- If Massachusetts were to implement an existing renewables requirement in the near term, the regional supply appears more than adequate to meet the requirement, even if significant amounts of existing renewables in the region retire.
- The supply of existing renewables exceeds the demand throughout the horizon in the high supply case, and for about ten years in the low supply case. The surplus of supply relative to demand reflects, in part, the fact that only three of the New England states have established RPS requirements.
- The difference in supply between the two cases is driven primarily by assumed reductions in imports to New England. Most of the renewable generation (in terms of production volume, although not necessarily in terms of number of plants) within New England are either hydro plants with relatively favorable cost structures or are among the various types of plants that

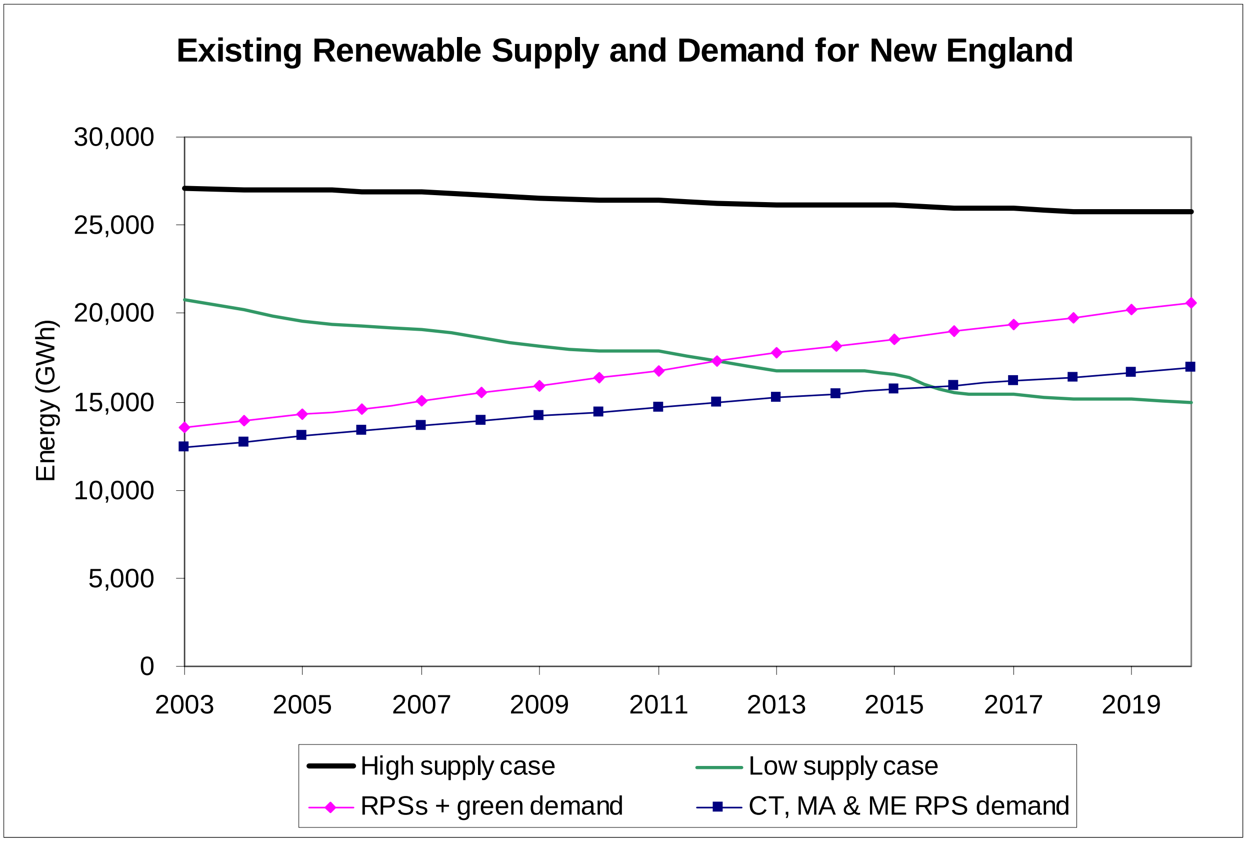
[44] This analysis did not address potential suppliers more than one control area away from NEPOOL. In addition to the suppliers mentioned here, significant quantities of renewable generation (particularly hydro) exist in Ontario, for example, which could compete for the New England renewables market.

have guaranteed revenue streams through long term power sale contracts. By 2010, only about half of these contracts will have expired.

- Some plausible future events (e.g., other states implementing existing renewables requirements) could produce a tighter supply outlook.

- Absent the existence and exercise of market power, it appears unlikely that retail electricity suppliers would have difficulty obtaining renewable generation (or renewable energy credits) to meet an existing renewables requirement, or that there would be a significant market premium for existing renewables in the near term. In this scenario, Massachusetts's retail suppliers and customers would absorb the transaction and administration costs of an existing renewables program, without materially affecting the supply of renewables in the region.

Figure 15: Comparison of Supply and Demand for Existing Renewable Resources



4. OTHER SENSITIVITY ANALYSES

Presented earlier were base, low, and high cost analyses for the potential costs of the Massachusetts RPS for qualifying new renewable resources. Here we examine three specific design choices facing DOER:

- What is the potential value of providing regulatory certainty to generators that the new renewables requirements in the Act will not be abruptly terminated?
- What are the potential impacts of alternative definitions of biomass eligibility on the new renewables requirements in the Act?
- What are the cost and impact implications of applying the RPS to each of a retail electricity supplier's products individually, versus to the supplier's aggregate sales to end-use customers in Massachusetts?

4.1. Regulatory Certainty Analysis

4.1.1. Objective

The objective of this sensitivity case is to evaluate the potential impacts of regulatory uncertainty on the cost of RPS compliance by systematically varying the assumed financing terms that renewable energy generators are able to obtain under different levels of regulatory uncertainty.

The Act specifies that, after 2009, the RPS is to increase at "an additional 1 per cent of sales every year thereafter until a date determined by the division of energy resources." Consequently, important policy design issues facing the DOER include:

- At what point after 2009, and on what basis, should DOER stop increasing the required percentage of new renewables by 1 percent per year?
- What should happen with the RPS requirement after the percentage has been capped?
- Under what conditions should the DOER phase-out and/or terminate the RPS?

As discussed in *White Paper #7: Design Issues*, resolution of these issues may impact the stability of the RPS, with its accordant impacts on the financing of renewable energy projects, the type and length of contracts established between retail suppliers and renewable energy generators, and the ultimate cost of RPS to retail suppliers and end-use customers in the Commonwealth. After all, while short duration policies can create immediate markets for renewables, as evidenced by the experience with renewables development in the 1980s, this development path can be destabilizing, making the renewable energy industries vulnerable to ongoing political forces. Policy duration and stability are especially important under a RPS, where new facilities will be brought on-line under the expectation of continued support over time through the sale of renewable energy attributes. If it is not clear that revenue from such attributes will be available in the long-term, the entry and financing requirements of new renewable projects will need to consider the possibility that long term revenues will reflect only “generic” wholesale electricity prices, at worst, or perhaps some small consumer-driven green premium in an environment where renewable supply might suddenly exceed demand by a substantial margin.

The cost analysis presented earlier in this paper assumed that the RPS would remain in effect well past 2009 (to at least 2019), either increasing or holding at a constant percentage, and *that this fact would be clear to investors and lenders* providing capital to renewable projects at the time of their investment decision. This certainty would allow relatively long debt repayment terms and limit the required returns on equity requirements, and consequently a lower incremental yearly cost of RPS compliance. Projects coming online to meet the RPS requirement were assumed to recover their capital investment through a real-levelized carrying charge of 17 percent.[45] This assumption is consistent with a 60/40 debt/equity financing ratio; a 12-year debt term; and a 16 percent annual return on the equity investment over 20 years. The same carrying charge was assumed in each of the sample years, implying a RPS requirement that is understood to remain in place until well after 2009.

If, on the other hand, the term of the RPS is uncertain and the financial community perceives that it may end (or decline significantly) as early as 2009, new renewables will likely face some combination of shorter financing periods, higher costs of capital, and higher required debt service coverage ratios as investors absorb the risk that RGPs may cease or diminish dramatically before the capital investment and loans are paid off. The net effect of such uncertainty would be to increase the “all-in” cost of power from new renewables, and therefore the cost of RPS compliance, in the near term. For example, if retail suppliers in Massachusetts were no longer required to meet any RPS purchase obligations after 2009, the cost of RPS compliance would likely increase significantly in the years leading up to this date as renewable generators shorten the amortization period of their above-market costs. This level of this potential increase (translating to an implied value of certainty with respect to the RPS requirement) is evaluated here.

4.1.2. Methods & Assumptions

This scenario assumes that regulatory uncertainty exists regarding whether the RPS purchase obligations will be maintained after 2009. The analysis hinges on the proposition that if the duration of the RPS requirement is in doubt, renewable project investors and lenders will have to plan the possibility that project revenues after 2009 may reflect only generic wholesale market prices, with little or no additional value from renewable attributes. We would expect a similar effect if project output is sold on a merchant basis or through long term contracts, because contract buyers (e.g., retail suppliers planning to sell in Massachusetts) will probably not be interested in making long term commitments past the date at which their RPS obligations end.

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[45] The real-levelized carrying charge assumption means that for each $100 of capital cost, a project would need to obtain revenues of at least $17 in the first year of project operation to cover its loan payments, depreciation, return on investment and taxes. Revenues would also need to cover any project expenses such as fuel and O&M costs. This estimated carrying charge requirement increases each year at the rate of general inflation; actual project financial requirements would vary somewhat from year to year.

While a comprehensive analysis of project financing assumptions is beyond the scope of this study, we performed a limited set of pro-forma analyses to test the effect of alternative financing assumptions. Recall that in the base case analysis, a target revenue per kWh for each renewable technology was derived assuming that the project would plan to achieve a pattern of revenues that remains approximately constant in real terms over 20 years. In this alternative scenario, it is assumed that renewable projects will price their output assuming that they will only achieve significant renewable attribute revenues through 2009, and will only receive prevailing generic wholesale prices thereafter. In other words, it is assumed that renewable generators will amortize most or all of their above-commodity-market fixed costs by the end of 2009.

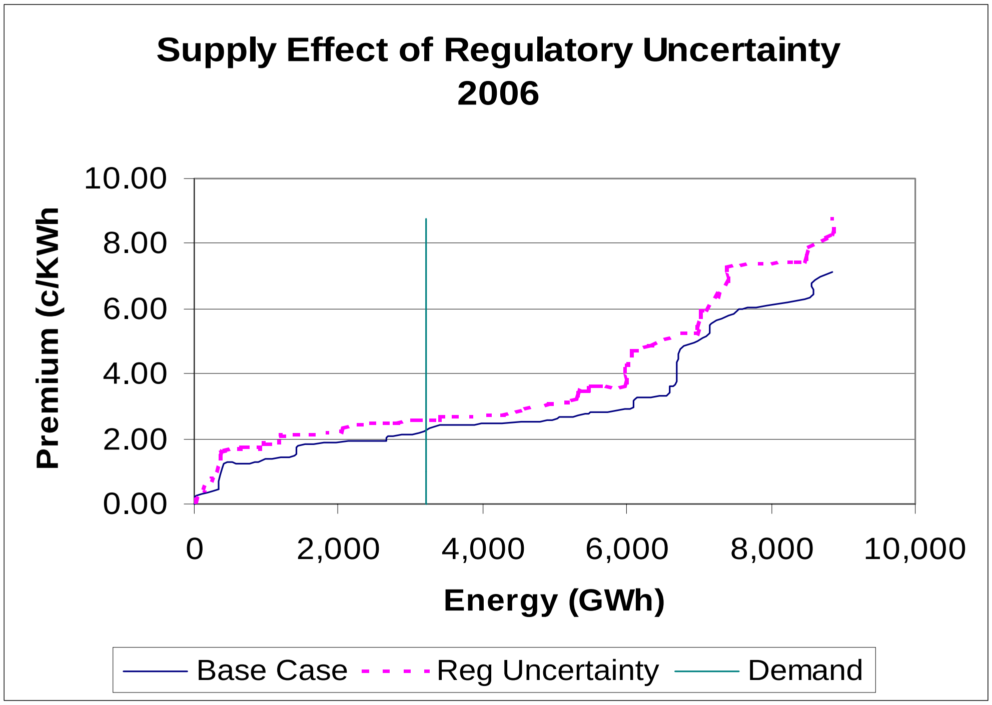
Our estimates suggest that a project coming online in 2003 would need to price its output through 2009 based on an annual carrying charge of around 20 percent, rather than 17 percent in the base case. If the term of the RPS obligation were not resolved by 2006, the effect on projects coming online in that year would be even more pronounced because they would only perceive four years (2006 through 2009) of revenue certainty. We estimate that a project coming online in 2006 would need to price its output through 2009 based on an annual carrying charge on the order of 26 percent. Because the online date is close to the date of regulatory certainty in question, this result is particularly sensitive to variations in input assumptions and should be considered only a rough indicator.

Using the results above as a guide, we tested the potential cost of regulatory certainly by developing alternative supply curves for 2003 and 2006. Specifically, we assumed that renewable projects reaching operation by 2003 would price their output through 2009 based on an annual carrying charge of 20 percent, rather than the 17 percent figure used in the base case analysis. For the 2006 supply curve, which would include a mix of projects reaching operation from 2002 to 2006, we assumed an average annual carrying charge rate of 23 percent. Relatively capital-intensive renewable projects (e.g., wind plants) would be more strongly affected than less capital-intensive projects (e.g., biomass cofiring).

Figure 16 illustrates the results of this sensitivity case on the supply curve for new renewables in 2003, relative to the base case. Because projects are assumed to require a more rapid recovery of their capital investments, the supply curve shows consistently higher premiums. Other summary results (all expressed in $2000) are as follows:

- The estimated RGP in 2003 is 2.60 cents/kWh, compared to 2.40 cents/kWh in the base case. The estimated RGP in 2006 is 2.56 cents/kWh, compared to 2.44 cents/kWh in the base case.
- Total estimated RPS compliance costs for 2003 in this case are estimated at $15.5 million, which represents an increase of $1 million (or about six percent) relative to the base case. Total RPS compliance costs for 2006 in this case are estimated at $39.0 million, which represents an increase of $1.7 million (or about five percent) relative to the base case.

Figure 16: Effect of Regulatory Uncertainty on RGP in 2006



These results reflect technology-specific increases in the cost of power from renewables, along with a shift in the order of the supply curve based on these alternative costs. In particular, less capital-intensive options (e.g., increasing output at existing biomass plants) appear more attractive in this scenario and are called upon earlier in the supply curve, offsetting the effect of cost increases for more capital-intensive options such as wind and landfill gas. Importantly, the NO_x emission benefits would be eroded somewhat by this uncertainty, as the emissions of biomass resources would displace zero-emission resources.

We did not conduct this alternative analysis for 2009 and 2012, largely because it seems unlikely that Massachusetts would fail to establish the path of its RPS requirement by then. Clearly, however, the effect of regulatory uncertainty would be significantly greater after 2006, for at least two reasons. First, as RPS demand increases, the marginal renewable resources that define the RGP tend to be more capital – intensive ones that are more strongly affected by financing assumptions. These resources are evident on the right hand portion of Figure 14, where the supply curve in this scenario diverges significantly from the base case. Second, if the duration of the RPS were not resolved until past 2006, new renewable projects built after 2006 would have only a few years in which to amortize their above-market costs, leading to higher premiums than shown here. At the extreme, a supplier seeking to purchase output from a new renewable source at or near 2009 might have to pay for all of the source's above-market costs in one or two years.

4.2. Biomass Sensitivity Analysis

4.2.1. Objective

The Act specifies that new low-emission, advanced biomass resources are eligible as new renewable resources for the Massachusetts RPS. DOER has interpreted this to include increases in generating capacity at existing biomass facilities that are made after December 31, 1997; DOER may also consider existing biomass facilities retrofitted with advanced conversion technologies to qualify as new renewable generating sources. However, the Act does not define what specific biomass technologies, plant configurations, or emissions requirements must be met for a biomass resource to be eligible. The DOER therefore has substantial authority to develop the specific implementing regulations that will define the eligibility of production from certain plants using biomass fuels.

In order to clarify the definition of eligible biomass resources, the DOER is currently considering different definitions for eligible biomass. For all technologies, they are considering different levels of NO_X and particulate emission rate requirements. Through work with the Department of Environmental Protection, the DOER hopes to determine feasibility and compatibility with emission disclosure regulations. In addition to these emission-based requirements, the DOER is considering specific interpretations for two different biomass configurations: existing biomass plants and biomass co-fired at fossil plants. This sensitivity analysis examines the potential impact of making the definition of eligible biomass less restrictive, and the resulting impact on cost.

4.2.2. Methods & Assumptions

Our previous analysis assumed that eligible biomass met certain NO_X emissions requirements, consistent with current DOER thinking in this area. Here we systematically vary two additional possible eligibility requirements to evaluate the potential cost implications of varying the biomass eligibility guidelines:

- With respect to an *existing biomass plant that is retrofitted* to reduce its air emissions below RPS threshold requirements, how much of the plant's generation should be eligible as "new" under the RPS? The analysis presented earlier assumed that only incremental generation above actual 1995-1997 output would qualify as new. An alternative approach, evaluated here, would qualify all output of the retrofitted plant as new based on the proposition that any historical generation did not constitute *eligible biomass*.
- In an instance of *biomass co-firing at a fossil-fired generating plant,*[46] what portion of the plant must meet DOER's proposed NO_x emission rate requirement? The analysis presented earlier assumed that the entire plant – including the majority of output that is generated from

[46] For the purpose of this analysis, we have assumed that installation of biomass co-firing at an existing fossil-fired plant would not constitute a "major modification" under the Clean Air Act, thereby requiring the entire plant to achieve New Source Performance Standards. If the implementation of biomass co-firing were to constitute a major modification, the economic potential of available biomass co-firing would be greatly reduced.

non-renewable fuel – must meet the emission requirement. An alternative approach, evaluated here, requires that only the portion of the plant's emissions that are imputed to the biomass fraction of production need meet the requirement.

A less restrictive requirement was modeled in the following manner. First, for all of the plants in the base case which we assumed could reduce their air emissions sufficiently to qualify as eligible renewables, the entire production (not only the incremental production above a 1995-1997 baseline) would qualify as a new renewable. Second, we assumed that several additional existing plants (250 MW in total capacity) would be able to become eligible by implementing emission control equipment, particularly those whose emissions are close to the biomass emission limit yet whose output was close to their maximum in the baseline years of 1995-1997. Finally, we assumed that for coal plants co-firing with biomass, only the emissions associated with the biomass fuel input (not the plant's average emissions) would need to meet a biomass eligibility threshold. As a result, this scenario includes another 1000 MW of coal (at 10% co-firing, 100 MW of equivalent biomass capacity) as an available renewable resource. Note that we did not assume any increase in co-firing at natural gas plants, since we assumed that the additional biomass would not impact facility emissions substantially.

4.2.3. Results

We simultaneously varied the portion of generation eligible for retrofitted existing plants (from only incremental production eligible to all production eligible) and whether a co-firing coal facility's emissions must come into compliance with the biomass emission limit on an entire-plant basis or for just the imputed incremental biomass fraction, as described above. The result was a five to seven percent decrease in average cost to Massachusetts end-use customers compared to the base case, as shown in Table 19.

Table 19 Percentage Decrease in Average Cost to MA End-use Customers

	2003	2006	2009	2012
Base Case	-7.0%	-5.7%	-6.8%	-5.1%

There are several potential impacts that would result from expanded biomass eligibility. By including all existing biomass facilities that retrofit to meet emission standards and putting the emission requirement for co-firing on only the incremental biomass emissions, we estimate (as shown above) that a notable decrease in cost to the customers will result. In addition, to the extent that biomass displaces wind production from the mix of generation, somewhat higher air emissions result, relative to the base case. Also, the technologies (increased capacity factors at existing biomass plants, and cofiring at existing coal plants) addressed in this sensitivity entail increased utilization of existing generating plants, rather than the construction of new renewable capacity. If the RPS requirement were terminated or reduced at some point in the future, these biomass options may not persist as long as other renewable resources. Specifically, it seems likely that the quantity of new renewable production would decline more dramatically as biomass capacity factors fall and fossil plants cease co-firing, relative to the base case in which more of the renewable production comes from new renewable plants that would likely continue to operate.

Note that there is a potential that the DOER's eligibility choices with respect to biomass will directly impact the regional supply of existing renewables. Every existing biomass facility that takes action and retrofits to meet NO_X emission requirements for the new renewable RPS would increase the stock of new resources and decrease the cost. However, the overall stock of existing biomass plants available to meet any potential existing renewable requirement would decrease. The result is that the existing resources depicted in Section 3 would be drawn down by any biomass facility who decided to decrease emissions and be counted as a new renewable resource. Yet we anticipate that this shift would not fundamentally impact the conclusions of the existing analysis, because the existing renewable resources are dominated by the sum of hydroelectric and Municipal Solid Waste resources. Therefore, this potential shifting of existing biomass resources to qualify as new does not appear to significantly alter the expectation that existing supply will exceed anticipated demand for several years. The DOER may wish to examine this issue more closely in the future to more thoroughly understand this interaction.

4.3. Product-Based vs. Company-Based RPS Compliance

4.3.1. Objective

The Act clearly states that every retail supplier must comply with the RPS. It does not indicate clearly, however, whether a retail supplier must provide a minimum percentage of eligible renewables to each end-use customer, or whether it may instead comply through providing eligible renewables to end-use customers in aggregate. This section explores whether a retail electricity supplier's compliance with the RPS should be defined, measured and verified across its aggregate retail sales to Massachusetts customers (aggregate, or **company-based compliance**), or whether it should be applied to each customer, also referred to here as **product-based compliance**.

4.3.2. Methods & Assumptions

In the base case analysis, we assume that RPS compliance would be product-based, thus requiring a minimum percentage of sales to each Massachusetts end-use customer be derived from eligible new renewable resources. At a minimum, product-based compliance requires that this minimum RPS amount be attributed to each customer, and would presumably be reflected in the product-based information disclosure label provided periodically to each customer[47]. If a supplier provides a customer with eligible renewable resources in excess of the RPS minimum, this excess quantity cannot be used to reduce the amounts allocated to other customers to a level below the RPS minimum.

Company-based compliance allows retail electricity suppliers to satisfy their RPS percentage requirements across sales in aggregate. Company-based compliance would be determined by dividing (a) the aggregate quantity of RPS-qualifying renewable sources of the supplier that are

[47] If a customer purchases a product offering with additional renewable content, then the disclosure label on the customer's bill will show the total renewable generation supported by the customer, from the RPS and consumer purchases.

dedicated to its end-use customers in the Commonwealth; by (b) the aggregate sales of the supplier to end-use customers in the Commonwealth[48].

At least two potential implications of company-based compliance merit consideration. First, under the company-based compliance method, consumer-driven demand for new renewables would not necessarily cause incremental development of renewables. A retail supplier could use renewables supported by purchasers of its green power products to offset some (or even all) of its company-wide minimum RPS requirements. [49] In this situation, consumers who purchase renewable-based retail electricity products would effectively be supporting their supplier's RPS compliance costs, without increasing the total development of renewables. The total costs paid by the sum of all Massachusetts customers would be lower than under a product-based compliance method, because fewer new renewables generating sources would be developed.

The second potential implication is that consumer perceptions of green power products could be adversely affected by a company-based compliance method. A reasonable consumer would expect that a retail electricity product sold at a premium and described as containing a certain fraction of new renewables might lead to or support an increased amount of renewables actually being developed. If company-based compliance were implemented in Massachusetts, retailers would be able to use some or all of customers' voluntary renewable purchases to offset their total company RPS requirements, rather than to purchasing additional renewables. Under a company-based RPS, customers would likely come to understand (through media reports, environmental advocate newsletters, and other means) that their purchase decisions are not actually causing new renewables to be developed. This could undermine consumer confidence and interest in green power products in general (those that provide incremental renewables as well as those that don't), both within and outside Massachusetts.

Finally, we note that the choice between company- and product-based compliance can affect the cost structure[50] for retail suppliers. Consider a retail supplier that chooses to market product "A" which includes 25% total new renewables, and product "B" which includes the minimum level of new renewables. If RPS compliance is on a company basis, then new renewables included in product "A" can offset the need to include any new renewables in product "B." If RPS compliance is on a product basis, then the retail supplier will have to allocate the minimum level of new renewables to product "B" (e.g. 1% in 2003) in addition to the 25% included in product "A." Thus, the retail supplier will have to purchase slightly more new renewables and will likely incur additional costs if compliance is on a product basis. However, the choice of company- or

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[48] It is important to note that (i) *company* as used here does not extend to consideration of the retail sales activities of a corporate entity beyond the borders of Massachusetts, nor to the actions of any corporate affiliate, but simply to the sales to customers in the Commonwealth by a retail supplier, and (ii) the scope of company-based compliance does not match the scope of *company resource portfolio* for Massachusetts information disclosure purposes, which is applied to all retail electric suppliers to end-use customers in the Commonwealth, on a New England-wide basis.

[49] Presumably, the retail supplier would have to disclose such circumstances to consumers or risk being accused of deceptive marketing.

[50] In this discussion, the term "cost" refers to financial obligations incurred by retail suppliers (e.g. for marketing, power and attributes) and the term "price" refers to the rate that a retail supplier charges consumers for purchase of an electricity product.

product-based compliance has no direct influence on how a retail supplier prices its electricity products for consumers. A retail supplier is free to set the price for any electricity product as it sees fit. There is no obligation for a retail supplier to recover all of its costs for a particular product directly from the sale of that product. The choice of company-based compliance will not necessarily cause cross subsidy between two electricity products or classes of customers.

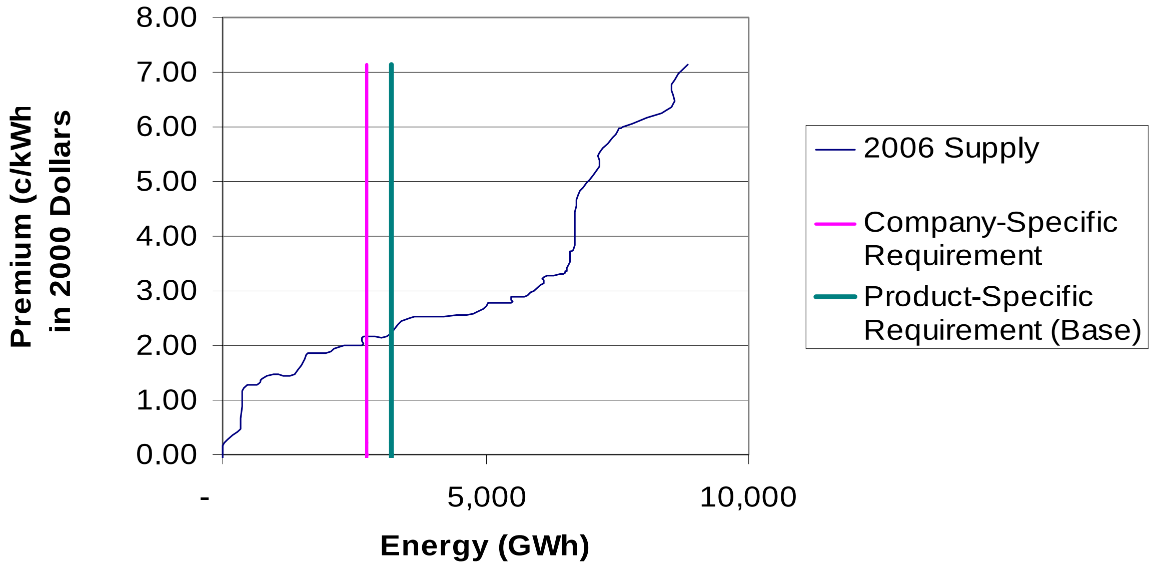
This sensitivity case tests the effects of a product-based vs. company based RPS requirement as follows. First, for each year of the analysis, we estimated the amounts of new renewables in the base case demanded by Massachusetts's customers through green power products. This estimate ranged from about 45 GWh in 2003 to about 350 GWh in 2012. Next, we addressed the fraction of the MA green demand that, under a company-based compliance method, would be used by suppliers to offset their RPS requirements rather than to develop incremental renewables. The extent to which retail suppliers would actually use voluntary customer purchases in this fashion is a significant uncertainty that is beyond the scope of this study. This analysis assumed that fifty percent of renewables purchased by Massachusetts customers through green power products were used to offset minimum RPS requirements rather than to develop new renewables.

Next, we explored the potential adverse effect of a company-based compliance approach on regional green demand. The key driver is the extent to which consumers would reduce their purchases of green electricity products, both those that provided incremental renewables and those that served to shift RPS requirements, if they understood some green products to be of the latter type and were not readily able to distinguish the offerings that sponsor the incremental development new renewables. Detailed analysis of this question is beyond the scope of this analysis. For illustrative purposes, we show the effect if green demand for the Northeast region (including the six New England states and New York) were reduced by fifty percent from our base case projection. Based on the regional nature of retail suppliers and media coverage, an effect of this magnitude seems plausible.

4.3.3. Results

Figure 17 shows the decrease in demand due to the company-specific RPS requirement, as compared to a product specific requirement, for 2006.

Figure 17 Demand Decrease Due to Company-Specific RPS Requirement - 2006



Overall, the variance in green demand is overshadowed by RPS compliance because renewable demand from RPS in the base case is up to four times as much as assumed customer-demanded renewables. Second, the impact of reducing total demand for non-RPS renewables in all of New England and New York was the major driver in reducing the average cost to customers for compliance. A summary of other results includes:

- Company compliance was estimated to result in a reduction of total renewable generation by 876 GWh, or 12 percent, compared to product-based compliance.
- The estimated RGP in 2003 is 2.10 cents/kWh, compared to 2.40 cents/kWh in the base case. The estimated RGP in 2006 is 2.17 cents/kWh, compared to 2.44 cents/kWh in the base case. The estimated RGP in 2009 is 2.52 cents/kWh, compared to 2.57 cents/kWh in the base case. The estimated RGP in 2012 is 2.57 cents/kWh, compared to 2.62 cents/kWh in the base case.
- Total estimated RPS compliance costs for 2003 in this case are estimated at $13.5 million, which represents a decrease of $2 million (or about thirteen percent) relative to the base case. Total RPS compliance costs for 2012 in this case are estimated at $117.8 million, which represents a decrease of $2.8 million (or about two percent) relative to the base case.
- These results reflect a shift in the demand curve, which intersects the supply curve at a lower price, thus decreasing RPS costs.

Appendix A

Administration and Transaction Cost Estimates[1]

The most significant cost of the Massachusetts RPS is expected to come from the added cost of renewable energy relative to undifferentiated energy supply. That said, significant costs might also arise from a retail supplier's internal administration and transaction costs associated with procuring sufficient renewables to comply with the RPS, and with documenting and verifying compliance with the RPS. Massachusetts end-use customers will also be faced with certain costs associated with DOER's administration of the RPS. These costs will vary considerably depending on the nature of the accounting and verification system selected by the DOER, the frequency with which firms engage in RPS-compliance activities (such as trading of renewable energy credits), the number of other Massachusetts generation information requirements that rely on the system, as well as the number of other states that elect to rely on similar systems.

This section presents our preliminary estimates for administration and transaction costs. In developing preliminary estimates for these costs, we split the administrative and transactional requirements of the Massachusetts RPS into a number of specific categories. The cost estimate for each category is assumed to depend on the accounting and verification option selected by the DOER.

The three accounting and verification options considered include:

- A restricted unbundling approach (e.g. tracking title to resource attributes by relying on a contract path, either bundled with energy, through discretionary allocations, or through transaction stages allowing restricted unbundling and rebundling); ,
- A renewable energy credits approach applied only in Massachusetts, and
- A full certificates approach applied to all generation sources on a regional basis.

The administrative and transaction cost categories include:

- Program administrative costs
  - Ongoing DOER administrative costs
  - Start-up costs associated with RPS administration and development of REC or certificates registry
  - Costs to operate a registry
- Supplier transaction costs
  - Retail supplier transaction costs
  - Wholesale transaction costs

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[1] After this analysis was completed, NEPOOL members voted on November 3, 2000 to pursue a region-wide certificates program, called the Generation Information System Database. This is equivalent option number three. While these costs are significantly less than a MA REC system, the final results of the analysis would not change significantly because Transmission and Administration costs are small compared to renewable generation costs.

Only incremental costs are included in the analysis, that is, those costs that the Massachusetts RPS directly and incrementally imposes on market participants and ultimately end-use customers in Massachusetts. Costs incurred by the DOER and market participants during the Advisory Group process and the subsequent development of RPS regulations and the creation and submission of the renewable energy credit study are considered to be sunk costs and are not included in this analysis. Administrative requirements and costs are derived, in part, from analysis presented in *White Paper #8: Administrative Issues and Information Requirements.*

Table 1, below, provides our preliminary estimates for the costs for each of the categories depending on the accounting and verification system used for the Massachusetts RPS. These estimates should be considered highly uncertain and preliminary. We assume that each of these costs will be passed on to end-use consumers in the Commonwealth in one way or another. Under the REC system, we assume that such a system is only used in Massachusetts. If the REC registry were to be used by other states, its incremental cost to Massachusetts end-use customers could decline as fixed costs are spread over a larger base.

Table 1. Program Administration and Transaction Cost Estimates

Cost Category/Accounting Method	Cost Estimate	Assumptions
Ongoing DOER Administrative Costs		
Restricted Unbundling	$450,000/year	3 FTE at $150k/year each
Renewable Energy Credits	$450,000/year	3 FTE at $150k/year each (product-based requirement)
Full Certificates	$225,000/year	1.5 FTE at $150k/year each
Administrative/Registry Start-up Costs		
Restricted Unbundling	$200,000	includes development of compliance filing protocols and education/ outreach/customer service
Renewable Energy Credits	$500,000	includes set-up of registry, developing the software specs for the registry, development and purchase of computer systems, education/outreach/ customer service, and initial burst of registration/certification applications

Full Certificates	$175,000	Includes education/outreach/ customer service as well as interface between DOER and the regional certificates registry (including treatment of behind the meter generation)
Registry Ongoing Costs		
Restricted Unbundling	$0/year	no registry required; ongoing compliance filing and protocol costs included in retail supplier transaction costs
Renewable Energy Credits	$425,000/year	2.5 FTE at $150k/year each; $50k/year computer support
Full Certificates	$90,000/year	0.5 FTE at $150/year each; $15k/year computer support
Retail Supplier Transaction Costs		
Restricted Unbundling	$2,550,000/year	per supplier: 1 FTE at $150k/year each; $5k/year for preparation of RPS compliance filing; $15k/year for RPS "audit" by CPA; 15 total retail suppliers
Renewable Energy Credits	$1,200,000/year	per supplier: $5k/year for preparation of compliance filing; 0.5 FTE at $150k/year each (product-based requirement); 15 total retail suppliers
Full Certificates	$525,000/year	per supplier: 0.2 FTE at $150k'year each; $5k/year for preparation of compliance filing; 15 total retail suppliers
Wholesale Transaction Costs		
Restricted Unbundling	depends on RPS volume	$1.5/MWh in 2003 decreasing to $0.5/MWh in 2012
Renewable Energy Credits	depends on RPS volume	$0.5/MWh in 2003 decreasing to $0.2/MWh in 2012
Full Certificates	depends on RPS volume	$0.5/MWh in 2003 decreasing to $0.2/MWh in 2012

Program Administrative Costs

- **Ongoing DOER Administrative Costs:** Ongoing DOER administrative requirements are detailed in *White Paper #8: Administrative Issues and Information Requirements*, and may include: (1) reviewing the functioning of the RPS and making mid-course corrections as necessary, (2) issuing advisory ruling on renewable energy plant eligibility, (3) accepting and verifying retail supplier compliance filings, (4) investigating potential non-compliance and applying sanctions for non-compliance, (5) reporting to industry stakeholders and the legislature on the process and functioning of the RPS, (6) hearing appeals to RPS-related decisions; and (7) potentially interacting with and overseeing a credits or certificates registry.

  These costs will vary considerably within and among years. On a levelized basis, we estimate that the functions identified above would require an incremental 3 full-time equivalent staff (FTE) of effort under a restricted unbundling accounting and verification regime, 2 FTE under the REC approach, and 1.5 FTE under a full certificates approach (a detailed breakdown of the FTE requirements by administrative task for a REC system is provided in *White Paper #8: Administrative Issues and Information Requirements*). We further assume that a fully loaded rate for an FTE is $150,000/year, including overhead, administrative support, office space and supplies, etc..

  The restricted unbundling approach is assumed to have the highest ongoing administrative costs given the need to verify individual compliance filings by retail supplier and to perform audits of contract path and related documentation on at least a spot-check basis. REC and certificate programs will require less effort to verify compliance filings. We further assume that the REC or certificates registry will bear much of the verification requirement under the REC and certificates options. Compliance verification is expected to be easier under a full certificates model than under a Massachusetts-specific REC system given a greater ability to account for and verify all generation in the region in a manner that obviates most double-counting and policy coordination issues. Under a certificates system, however, DOER may need to specifically address the administrative needs of certain aspects of the RPS not covered by the certificates administrator, including the tracking and verification of behind-the-meter generation.

- **Administrative/Registry Start-up and First Year Costs:** Administrative/registry start-up and first year costs might include: (1) designing the specifications for the software and hardware systems needed for registry set-up; (2) purchasing and designing the computer hardware and software systems needed to establish the registry functions; (3) designing the specifications for outsourced operation of a registry, and contracting for a vendor to operate the registry; (4) handling the initial burst of facility and retail supplier registration and certification expected shortly after registry start-up; (5) development of a detailed compliance filing protocol in the case of the restricted unbundling tracking model, and far less extensive protocols under REC or certificates systems; and (6) development of education, outreach, and customer service materials.

  We estimate these costs at $500,000 under the REC system, $200,000 under the restricted unbundling case, and $175,000 under a full certificates system. Under the certificates system, we assume that the incremental costs associated with the Massachusetts RPS are restricted to the education, outreach, and customer service component of the requirements detailed above, with some additional cost in ensuring that the regional certificates system can easily be adapted for use in Massachusetts RPS compliance. Additional costs might also be incurred by the DOER to handle behind-the-meter generation, which may not be handled adequately by the regional certificates administrator. Other costs are assumed to be incurred by the regional administrator in lieu of a Massachusetts RPS[2]. Under restricted unbundling, development of a detailed compliance filing protocol (building off similar work in California and other states) would also be required. A Massachusetts-specific REC system is projected to have the highest cost in this category, given incremental registry system design and hardware/software procurement costs. These costs are highly uncertain, and could easily vary by plus or minus $200,000 depending, in part, on the ease of adapting existing software systems.

- **Registry Ongoing Costs:** In addition to start-up costs, a REC or certificates registry would also have ongoing costs, including: (1) registration and certification of plant eligibility (including contractual and on-site audits); (2) certification of production from generators; (3) establishment of REC or certificates accounts for all relevant market participants; (4) operation of a web-based REC or certificates registry; (5) receiving and helping to verify retail supplier compliance filings; (6) development of systems to scale-up a REC registry to a more regional and multi-attribute system; and (7) customer service. These function may or may not be outsourced.

  Under the restricted unbundling case, where no registry is required, these costs are assumed to be zero. Under a REC system, the incremental costs are estimated to equal 2.5 FTE (at $150,000/year each) plus $50,000/year in computer support. These FTE are expected to be split among management, analysis (and audit), technical, and administrative functions. Under a full certificates system used by multiple states and for multiple requirements, the incremental cost associated with the Massachusetts RPS is expected to be much more modest. We assume an 0.5 FTE requirement to ensure that such a system meets Massachusetts RPS requirements on an ongoing basis (e.g., ensure that Massachusetts-specific eligibility requirements are reflected in the regional system) plus $15,000/year in incremental computer support (including ensuring a seamless link between the full certificates registry and the DOER RPS compliance verification requirements).

Supplier Transaction Costs

- **Retail Supplier Transaction Costs:** Retail supplier transaction costs refer to the incremental costs imposed on retail suppliers associating with learning about the Massachusetts RPS requirements, arranging for and contracting for the required renewable generation (or RECs

[2] An alternative approach would consider that the Massachusetts RPS is one of several drivers for establishing a full certificates program, and that there would be some degree of sharing of startup costs among the states. Such an approach might allocate costs based on share of load – Massachusetts has approximately 40% of New England load – and among the different purposes – Massachusetts has three generation attribute requirements. If the costs of establishing a full certificates system was $1.5 million, then the MA RPS share might be ($1.5 m + 40%/3) = $200,000). Such an approach would increase our cost estimates for the certificates program.

or certificates), performing incremental risk management activity, and preparing RPS compliance filings and associated documentation. Based on our collective experience in wholesale energy and renewable energy transactions, we estimate the FTE requirements for these functions to be 1 FTE in the restricted unbundling case, 0.3 FTE under RECs, and 0.2 FTE under full certificates (though these requirements will certainly decline over time, we assume a levelized FTE requirement here). FTE requirements are estimated to be higher under the restricted unbundling case, given that solicitations and/or negotiation of numerous bilateral contracts may be required (note that if an APX-like green market developed in Massachusetts, these FTE requirements could decline substantially). Incremental FTE requirements under RECs and certificates approaches are expected to be low. We estimate a slightly lower FTE for full certificates (0.2 FTE) than for REC systems (0.4 FTE) due to assumed efficiencies if all attributes are traded as in a full certificates system.

We further assume a $5,000/year cost in each case for compliance filing preparation. Finally, under the restricted unbundling model we assume that the DOER requires each retail supplier to provide a contractual "audit" prepared by a CPA attesting to and demonstrating compliance with the RPS. Based on experience in California, the cost of such an audit is assumed to be $15,000 per "audit" (note that due to requirements on the term "audit," the California system is actually referred to as "agreed upon procedures"). Finally, we assume that 15 retail suppliers are active in the Massachusetts market, consistent with experience in other retail electricity markets (e.g., Pennsylvania and California).

- **Wholesale Transaction Costs:** Wholesale transaction costs are perhaps the largest but also most difficult cost to estimate with confidence. These costs include the incremental costs to generators associated with learning about the Massachusetts RPS requirements, registering and certifying plant eligibility for the RPS; certification of generation; arranging for and contracting with retail supplier or brokers for the sale of renewable generation, RECs, or certificates, and brokerage fees that might be imposed by wholesale brokers.

  Data on these costs come from transactions costs on wholesale commodity electricity transactions, brokerage fees imposed by the Automated Power Exchange (APX) green market in California, brokerage fees charged in emissions trading markets, and wholesale premiums available to renewable generators in locations where eligible supply far exceed eligible demand (e.g., California green market, Maine and Connecticut RPS markets).

  Based on our understanding of wholesale electricity markets, transaction costs declined from as much as 0.3 cents per kWh to well below 0.1 cents per kWh as wholesale markets became more efficient and competitive over the last decade**.** Experience with other credit trading markets suggests that brokerage fees often start relatively high (5-7% of credit trading value) but frequently decline rapidly to as low or lower than 1% of the credit trading value as volume increases and market inefficiencies decline**.**[3] APX charges a trading fee for

[3] The costs of trading under the SO2 allowance and RECLAIM programs, for example, are relatively low. Brokers handle most of the trades under the SO_2 allowance program. They charge both the buyer and the seller a commission of $0.50 per allowance, for a total cost of $1.00 per allowance. The price of an allowance has fluctuated between $100 and $200, so the transaction cost is less than 1%. Many of the RECLAIM RTCs are sold through periodic auctions. Auction managers charge a fixed fee to both the buyer and the seller of either 3.5% or $35 per ton transacted plus a flat $150 per order placed. The total fee includes a $50 fee charged by SCAQMD to register each

renewable generation transactions in California equal to approximately 12.5 cents per MWh, or 0.0125 cents per kWh[4].

Finally, in both the California green market and the Maine RPS, where eligible renewable generation far exceeds demand, such generation still commands a premium. This premium may reflect actual wholesale transaction costs, or conditions of market power, or market dis-equilibrium. Under the APX in California, for example, generic renewable energy "tickets" from May 1999 through April 15, 2000 have averaged 0.14 cents/kWh premium over commodity electricity. Similarly, eligible renewable generators in Maine have reportedly received an 0.1 – 0.15 cents/kWh premium from retail suppliers seeking to meet their RPS requirements (in the very early stages of the Maine market)[5]. (We have some evidence that existing renewables to serve the Connecticut RPS will receive a similar payment). =

Though this experience provides only modest insight into the potential wholesale transaction costs that we might see under the Massachusetts RPS, it provides a starting point for estimating these costs and suggests that these costs may decline substantially over time. Using this data, we assume that under the restricted unbundling case, wholesale transaction costs equal 0.15 cents/kWh in 2003, declining to 0.05 cents/kWh by 2012. For both certificates and credits (where transaction fees are expected to be lower given standardization in contracts and the development of low-cost exchanges), wholesale transaction costs are assumed to be 0.05 cents/kWh in 2003 declining to 0.02 cents/kWh by 2012. These costs include generator and broker FTE requirements, overhead, and computer systems.

Summary

Aggregating these assumptions, the following overall cost estimates are offered:

- **Restricted Unbundling:**

  Start-up costs: $200,000

  Fixed ongoing costs: $3,000,000/year

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trade. The SCAQMD collects the registration fee each time, so it receives at least $100 for each trade through a broker. Thus, the total cost to complete a trade is $300 plus $70 per ton. An average trade consists of a little over 1,000 tons and the weighted average price has been just over $1,000 per ton. Thus the transaction cost averages about 7% of the price. (Margaree Consultants Inc., "Review of Alternative Emissions Trading Options," Pilot Emissions Reduction Trading (PERT) Project, Toronto, September, 1998, p. 46. (available at www.pert.org)

[4] Based on conversation with Jan Pepper, APX, May 2000. Fees consist of $0.03 per MWh to each participant for just for the "green tickets". Energy is a separate transaction with a separate fee: if within the in APX market, an additional energy trading fee of 3 cents per kWh is charged to each side of the transaction. In addition, if APX performs scheduling duties, an additional fee of 6.25 cents/kWh is charged.

[5] Based on a very unscientific survey of a few participants in the Maine RPS market.

Variable ongoing costs: \$1.5/MWh in 2003 decreasing to \$0.5/MWh by 2012

- **Massachusetts RECs**

  Start-up costs: \$500,000

  Fixed ongoing costs: \$1,600,000/year

  Variable ongoing costs: \$0.5/MWh in 2003 decreasing to \$0.2/MWh by 2012

- **Full Certificates**

  Start-up costs: \$175,000

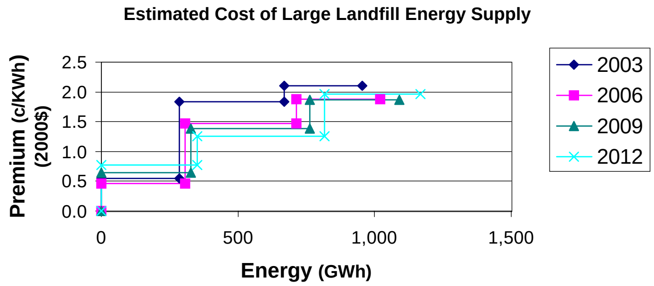
  Fixed ongoing costs: \$840,000/year

  Variable ongoing costs: \$0.5/MWh in 2003 decreasing to \$0.2/MWh by 2012

APPENDIX B
Renewable Energy Technology Assumptions and Results

One-Page Summaries

Large Landfill Gas



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	115	955
2006	118	1020
2009	121	1089
2012	124	1167

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR LARGE LANDFILL GAS FACILITIES

Assumed: ICE with heat rate of 11,000 Btu/kWh; and production distributed uniformly throughout the year

	2003
Capital cost ($/kW)	$1,800
Variable O&M ($/kWh)	$0.015
Fixed O&M ($/KW-yr)	$0
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/KWh)	0
Capacity Factor	95%

Notes *Capital cost includes gas collection system*
Fuel is assumed to be generated on-site and free.

To extraoplate over time, we reflected a combination of:
- declining resource quality
- depletion of methane at capped landfills over time
- addition of new waste-in-place to uncapped landfills
- technology evolution - over time
(shift from ICE to fuel cells; increased CF; lower installation cost and more capacity at existing LF)

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	5.18	5.03	4.89	4.75

Commodity market value of production	2003	2006	2009	2012
(cents/kWh)	3.34	3.56	3.51	3.49

	2003	2006	2009	2012
Over-market premium (c/kWh)	1.84	1.47	1.38	1.25

PREMIUM DISTRIBUTION AROUND AVERAGE

Some LFG will be cheaper and some more expensive. This will be driven by whether:
- collection system is a sunk cost (since some, but not all landfills already have collection systems in place);
- scale economies of facility and infrastructure
- qualification for Section 29 gas tax credits
- which technology uses the gas - in later years, we assume more efficient microturbines and fuel cells are used.

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

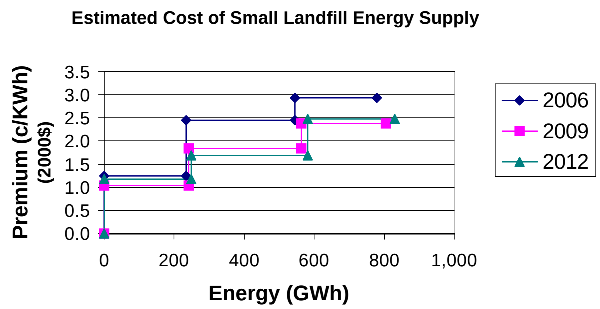
	2003	2006	2009	2012
High cost premium (c/kWh)	2.099	1.873	1.870	1.964
Ave. cost premium (c/kWh)	1.840	1.470	1.381	1.252
Low cost premium** (c/kWh)	0.546	0.463	0.646	0.777

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects
** Note that the low costs reflect those projects that already have gas collection systems in place, some of whom get the tax rebate.

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	30%	40%	30%

Small Landfill Gas



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	0	0
2006	93	778
2009	97	804
2012	100	830

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR SMALL LANDFILL GAS FACILITIES

small landfills install collection and generation equipment between 2004-2006
cost is greater than that for large landfills by:
1 cents/kWh in 2006 and
0.5 cents/kWh in 2009 and 2012
use all other assumptions, as stated in "large landfill gas" summary

To extraoplate over time, we reflected a combination of:
- declining resource quality
- depletion of methane at capped landfills over time
- addition of new waste-in-place to uncapped landfills
- technology evolution - over time
(shift from ICE to fuel cells; increased CF; lower installation cost and more capacity at existing LF)

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	N/A	6.03	5.39	5.25

Commodity market value of production

	2003	2006	2009	2012
(cents/kWh)	N/A	3.58	3.55	3.55

	2003	2006	2009	2012
Over-market premium (c/kWh)	N/A	2.45	1.84	1.69

PREMIUM DISTRIBUTION AROUND AVERAGE

Some LFG will be cheaper and some more expensive. This will be driven by whether:
- collection system is a sunk cost;
- scale economies of facility and infrastructure
- qualification for Section 29 gas tax credits

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

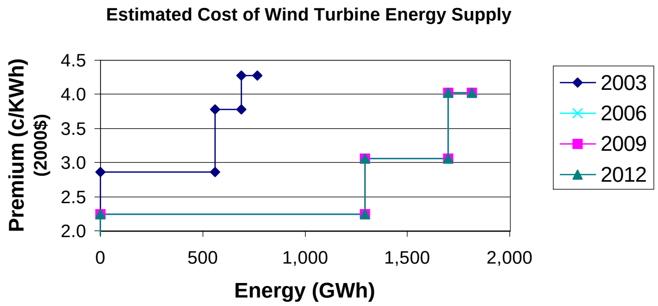
	2003	2006	2009	2012
High cost premium (c/kWh)	0.00	2.93	2.38	2.48
Ave. cost premium (c/kWh)	0.00	2.45	1.84	1.69
Low cost premium (c/kWh)	0.00	1.24	1.03	1.17

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	30%	40%	30%

Wind Projects (specific)



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	284	766
2006	656	1814
2009	656	1814
2012	656	1814

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR WIND TURBINE FACILITIES

Major assumptions:

-Amounts and costs developed based on consulting team's familiarity with existing and proposed projects.
- Unlike all other technologies, these projects were included on a project-by-project basis.
- Projects are located in New England, New York and Canada.
- Federal PTC would be reauthorized at a lower level (0.5 cents/kWh in $2000) for projects developed between 2001 through 2006.
- Technology improvements are assumed to reduce capital cost over time.
- Known SBC funds for NY projects were included, but all other SBC funds were ignored.

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	6.24	5.47	5.47	5.47

Commodity market value of production	2003	2006	2009	2012
(cents/kWh)	3.18	3.02	3.02	3.02

	2003	2006	2009	2012
Over-market premium (c/kWh)	3.16	2.54	2.54	2.54

PREMIUM DISTRIBUTION AROUND AVERAGE

Some wind projects will be cheaper and some more expensive. This will be driven by whether:
-quality of the wind resource at each location;
- scale economies of facility and infrastructure; and
- qualification for tax credits (on a state basis and national basis).

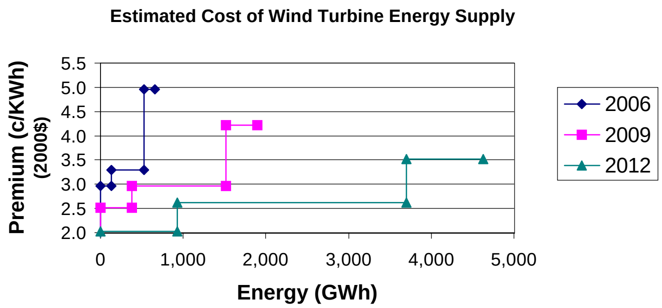
Project specific information helped us determine a range of cost premiums:

	2003	2006	2009	2012
High cost premium (c/kWh)	4.28	4.02	4.02	4.02
Med. cost premium (c/kWh)	3.78	3.06	3.06	3.06
Low cost premium (c/kWh)	2.86	2.24	2.24	2.24

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

The above cost premiums were aggregated from project specific information into three average costs: high, med and low

Wind Projects (Generic)



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	0	0
2006	250	657
2009	700	1898
2012	1650	4628

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR WIND TURBINE FACILITIES

	2003
Capital cost ($/kW)	$900
Variable O&M ($/kWh)	$0.005
Fixed O&M ($/KW-yr)	$17
Capacity Factor	29%

Major assumptions:
- technology improvement reducing capital cost over time
- federal PTC at 0.5 cents/kWh for projects developed 2001 through 2006.

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	7.19	6.67	6.30	5.96

Commodity market value of production

	2003	2006	2009	2012
(cents/kWh)	3.12	3.38	3.34	3.34

	2003	2006	2009	2012
Over-market premium (c/kWh)	4.07	3.30	2.96	2.62

PREMIUM DISTRIBUTION AROUND AVERAGE

Some wind projects will be cheaper and some more expensive. This will be driven by whether:
-quality of the wind resource at each location;
- scale economies of facility and infrastructure; and
- qualification for tax credits (many projects captures are outside of the US).

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

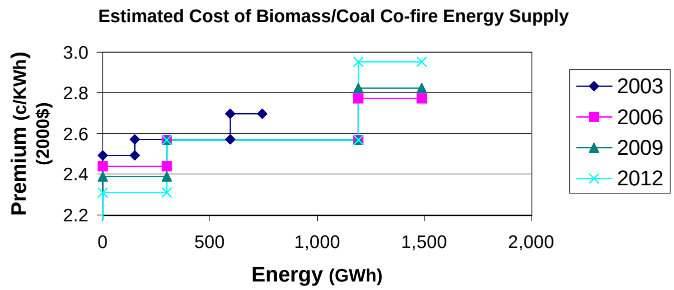
	2003	2006	2009	2012
High cost premium (c/kWh)	6.23	4.96	4.22	3.51
Ave. cost premium (c/kWh)	4.07	3.30	2.96	2.62
Low cost premium (c/kWh)	3.86	2.96	2.52	2.02

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

Biomass Co-Firing with Coal



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	100	745
2006	200	1489
2009	200	1489
2012	200	1489

* For each year, these maximum capacities take into account:

1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR BIOMASS/COAL CO-FIRE FACILITIES

	2003
Capital cost ($/kW)	$261
Variable O&M ($/kWh)	$0.000
Fixed O&M ($/KW-yr)	$10
Fuel Cost ($/KWh)	$0.0184
Heat Rate (Btu/KWh)	10,489
Capacity Factor	85%

Major assumptions:

- fuel is pulverized biomass
- Costs and commodity market value of production are incremental to existing coal plant costs.
- substantial biomass volumes available at $3.50/mmBTU
- sustainable biomass fuel will cost about $1.75/mmBTU above coal
- biomass will provide about 10 percent of total plant fuel input
- capital cost: incremental fuel handling equipment and emission control
- biomass cofiring will not trigger Clean Air Act NSPS.

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	2.57	2.57	2.57	2.57

Commodity market value of production	2003	2006	2009	2012
(cents/kWh)	0.00	0.00	0.00	0.00

	2003	2006	2009	2012
Over-market premium (c/kWh)	2.57	2.57	2.57	2.57

PREMIUM DISTRIBUTION AROUND AVERAGE

Some biomass co-firing with coal will be cheaper and some more expensive. This will be driven by whether:

- the coal plant is close to the biomass resource (i.e. transport costs will dominate fuel cost);
- cost of bringing the incremental emissions into NOx and PM compliance; and
- coal technology used on site (i.e. some are easier and cheaper to co-fire than others).

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

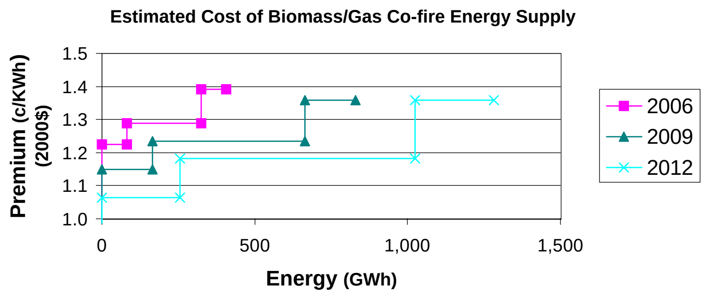
	2003	2006	2009	2012
High cost premium (c/kWh)	2.699	2.773	2.824	2.953
Ave. cost premium (c/kWh)	2.570	2.567	2.567	2.567
Low cost premium (c/kWh)	2.493	2.439	2.388	2.311

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

Biomass Co-Firing with Natural Gas



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	0	0
2006	50	407
2009	100	830
2012	150	1281

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR BIOMASS/GAS CO-FIRE FACILITIES

	2003
Capital cost ($/kW)	$600
Variable O&M ($/kWh)	$0.001
Fixed O&M ($/KW-yr)	$5
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/KWh)	9,300
Capacity Factor	92%

Major assumptions:
- fuel is gasified biomass
- sustainable biomass fuel cost approx. equal to pipeline gas ($3.50/MMBtu
  Therefore, incremental fuel cost is zero. All other costs are incremental
- biomass will provide about 10 percent of total plant fuel input
- capital cost reflects gasifier & incremental fuel handling equipment
- biomass cofiring will not trigger NSPS or other retrofits
- baseload plant operation
- Costs and commodity market value of production
  are incremental to existing coal plant costs.

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	0.00	1.29	1.24	1.18

Commodity market value of production	2003	2006	2009	2012
(cents/kWh)	0.00	0.00	0.00	0.00

	2003	2006	2009	2012
Over-market premium (c/kWh)	0.00	1.29	1.24	1.18

PREMIUM DISTRIBUTION AROUND AVERAGE

Some biomass co-firing with natural gas will be cheaper and some more expensive. This will be driven by whether:
- the natural gas plant is close to the biomass resource (i.e. transport costs will dominate fuel cost);
- cost of bringing the incremental emissions into NOx and PM compliance; and
- facility configuration (i.e. where space is available for fuel preparation and gasifier).

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

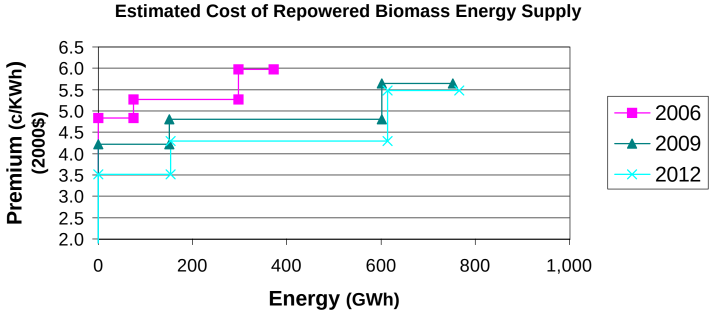
	2003	2006	2009	2012
High cost premium (c/kWh)	0.00	1.39	1.36	1.36
Ave. cost premium (c/kWh)	0.00	1.29	1.24	1.18
Low cost premium (c/kWh)	0.00	1.22	1.15	1.06

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

Coal plants Repowered with Biomass



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	0	0
2006	50	372
2009	100	752
2012	100	767

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR REPOWERED BIOMASS FACILITIES

Major assumptions:

- placeholder cost/kWh figure based on info from developers.
- only includes small coal plants that are currently deactivated
  (and therefore not conversion of existing coal plants in operation)
- range of cost of energy was given as: 7 - 8 cents/ kWh
- on top of gived cost of energy, we included SNCR (we assume this is needed to meet NOx emission requirments)
- substantial biomass volumes available at $3.50/mmBTU

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	0.00	8.88	8.37	7.86

Commodity market value of production

	2003	2006	2009	2012
(cents/kWh)	0.00	3.61	3.57	3.56

	2003	2006	2009	2012
Over-market premium (c/kWh)	0.00	5.27	4.80	4.30

PREMIUM DISTRIBUTION AROUND AVERAGE

Repowering of old coal plants with biomass will be cheaper in some instances and more expensive in others. This will be driven by wh
- the plant is close to the biomass resource (i.e. transport costs will dominate fuel cost);
- cost of bringing the incremental emissions into NOx and PM compliance; and
- facility configuration (i.e. if space is available for any retrofits or reconfiguration).

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

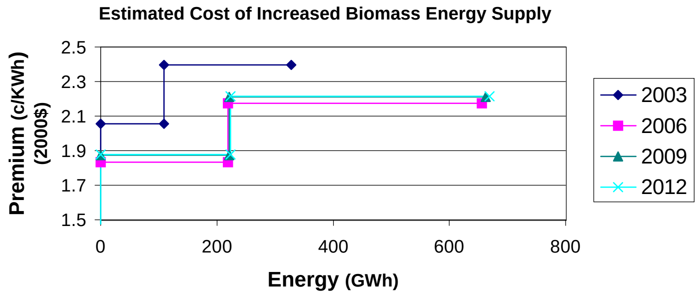
	2003	2006	2009	2012
High cost premium (c/kWh)	0.00	5.98	5.64	5.48
Ave. cost premium (c/kWh)	0.00	5.27	4.80	4.30
Low cost premium (c/kWh)	0.00	4.83	4.22	3.51

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

Increased Biomass Production at Existing Plants



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	75	329
2006	150	657
2009	150	664
2012	150	670

* For each year, these maximum capacities take into account:

1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR INCREASED BIOMASS FACILITIES

	2003
Capital cost ($/kW)	$50
Variable O&M ($/kWh)	$0.002
Fixed O&M ($/KW-yr)	$0.5
Fuel Cost ($/MMBtu)	$3.50
Heat Rate (Btu/KWh)	15,000
Capacity Factor (increase from historical)	50%

Major assumptions:

- only increased output over historical qualifies as "new" in MA
- increased output will be somewhat weighted toward offpeak hours
- capital cost reflects placeholder value for emission control equipment
- substantial biomass volumes available at $3.50/mmBTU

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	5.66	5.66	5.65	5.65

Commodity market value of production	2003	2006	2009	2012
(cents/kWh)	3.26	3.48	3.44	3.44

	2003	2006	2009	2012
Over-market premium (c/kWh)	2.40	2.17	2.21	2.22

PREMIUM DISTRIBUTION AROUND AVERAGE

The cost of increasing production at existing biomass plants will be driven by whether:
- the plant is close to the biomass resource (i.e. transport costs will dominate fuel cost);
- cost of bringing the incremental emissions into NOx and PM compliance; and
- facility configuration (i.e. if space is available for any retrofits or reconfiguration).

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

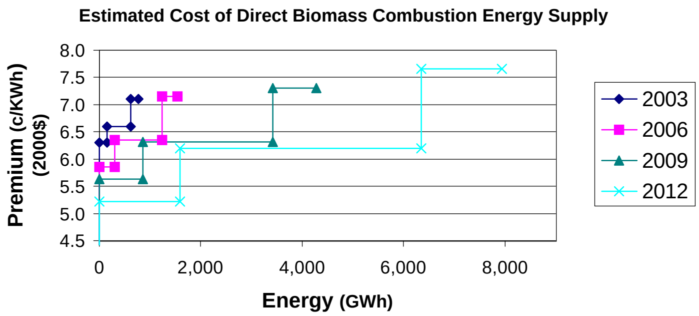
	2003	2006	2009	2012	Emission control notes
High cost premium (c/kWh)	0.00	0.00	0.00	0.00	We assumed none needed SCR.
Ave. cost premium (c/kWh)	2.40	2.17	2.21	2.22	We assumed SNCR is needed.
Low cost premium (c/kWh)	2.06	1.83	1.87	1.88	Operational tuning sufficient

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	0%	67%	33%

Direct Biomass Combustion



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	100	771
2006	200	1542
2009	550	4282
2012	1000	7940

* For each year, these maximum capacities take into account:

1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR DIRECT BIOMASS COMBUSTION FACILITIES

	2003
Capital cost ($/kW)	$1,795
Variable O&M ($/kWh)	$0.009
Fixed O&M ($/KW-yr)	$61
Fuel Cost ($/MMBtu)	$3.50
Heat Rate (Btu/KWh)	12,322
Capacity Factor	88%

Major assumptions:

- baseload plant operation
- substantial biomass volumes available at $3.50/mmBTU

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	9.96	9.96	9.88	9.75

Commodity market value of production	2003	2006	2009	2012
(cents/kWh)	3.36	3.60	3.56	3.55

	2003	2006	2009	2012
Over-market premium (c/kWh)	6.60	6.36	6.32	6.20

PREMIUM DISTRIBUTION AROUND AVERAGE

Some direct combustion of biomass will be cheaper and some more expensive. This will be driven by whether:

- the plant is close to the biomass resource (i.e. transport costs will dominate fuel cost);
- cost of bringing the incremental emissions into NOx and PM compliance; and
- scale economies of facility and infrastructure.

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

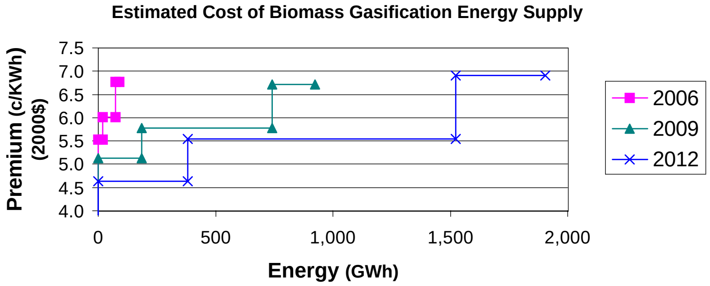
	2003	2006	2009	2012
High cost premium (c/kWh)	7.10	7.15	7.31	7.66
Ave. cost premium (c/kWh)	6.60	6.36	6.32	6.20
Low cost premium (c/kWh)	6.30	5.86	5.63	5.22

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

Biomass Gasification



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	0	0
2006	13	91
2009	125	925
2012	250	1904

* For each year, these maximum capacities take into account:
1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR BIOMASS GASIFICATION FACILITIES

	2003
Capital cost ($/kW)	$2,500
Variable O&M ($/kWh)	$0.005
Fixed O&M ($/KW-yr)	$43
Fuel Cost ($/MMBtu)	$3.50
Heat Rate (Btu/KWh)	9,223
Capacity Factor	82%

Major assumptions:
- baseload plant operation
- substantial biomass volumes available at $3.50/mmBTU
- technology improvement reduces capital cost over time

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	0.00	9.62	9.35	9.10

Commodity market value of production

	2003	2006	2009	2012
(cents/kWh)	0.00	3.61	3.57	3.56

	2003	2006	2009	2012
Over-market premium (c/kWh)	0.00	6.01	5.78	5.54

PREMIUM DISTRIBUTION AROUND AVERAGE

Some direct combustion of gasified biomass will be cheaper and some more expensive. This will be driven by whether:
- the plant is close to the biomass resource (i.e. transport costs will dominate fuel cost);
- cost of bringing the incremental emissions into NOx and PM compliance; and
- the advancement of this technology which is not yet commercial.

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

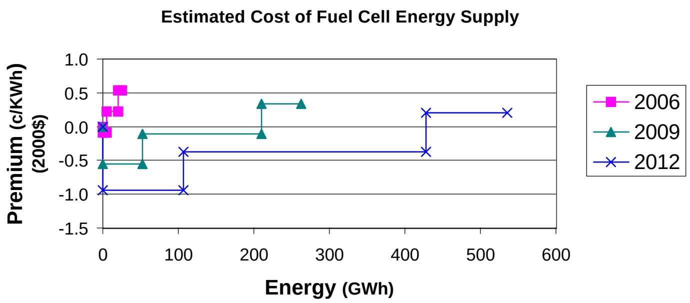
	2003	2006	2009	2012
High cost premium (c/kWh)	0.00	6.78	6.71	6.91
Ave. cost premium (c/kWh)	0.00	6.01	5.78	5.54
Low cost premium (c/kWh)	0.00	5.53	5.12	4.63

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

Fuel Cells



	Annual Maximum Available Capacity* (MW)	Total Estimated Energy (GWh)
2003	0	0
2006	3	26
2009	34	263
2012	68	535

* For each year, these maximum capacities take into account:

1) resource availability
2) permitting feasibility
3) technology commercial potential
4) developer reaction to renewables market

ASSUMPTIONS FOR FUEL CELL FACILITIES

	2003
Capital cost ($/kW)	$2,500
Variable O&M ($/kWh)	$0.000
Fixed O&M ($/KW-yr)	$110
Fuel Cost ($/MMBtu)	$3.50
Heat Rate (Btu/KWh)	3,000
Capacity Factor	85%

Major assumptions:

- fuel cells using pipeline gas qualify in CT, not in MA
- no substantial volume through 2006
- technology improvement reduces capital cost over time
-High cost case assumes low penetration, BUT constrained supply of other tech. provides opportunity for fuel cells at a higher capital cost ($3,500/kW
-Low cost case assumes significant penetration, therefore economies of scale reduce capital costs to $1,500/KW
- Premium measured vs. *retail* electricity costs.

RESULTING COST AND OVER-MARKET PREMIUM(all in 2000 Dollars)

	2003	2006	2009	2012
Cost (cents/kWh)	0.00	7.81	7.44	7.17

RETAIL value of production

	2003	2006	2009	2012
(cents/kWh)	0.00	7.59	7.55	7.54

	2003	2006	2009	2012
Over-market premium (c/kWh)	0.00	0.23	-0.11	-0.37

PREMIUM DISTRIBUTION AROUND AVERAGE

Some fuel cells will be cheaper and some more expensive. This will be driven by whether:
- transmission and distribution savings (depends on location, etc.);
- scale economies of facility and infrastructure
- the advancement of this technology which is just emerging commercially.

Therefore, we assumed a range reflecting these factors, which resulted in a range of premiums around the average:

	2003	2006	2009	2012
High cost premium (c/kWh)	0.000	0.538	0.337	0.205
Ave. cost premium (c/kWh)	0.000	0.226	-0.110	-0.369
Low cost premium (c/kWh)	0.000	-0.087	-0.556	-0.942

The above table shows the distribution of the overmarket premium to the high, low, and average cost projects

To complete the distribution of costs around the average, we assigned a percentage of total capacity available at each cost level. The amount capacity for each is shown in the graph at the top. We assumed the fractions remain constant over time.

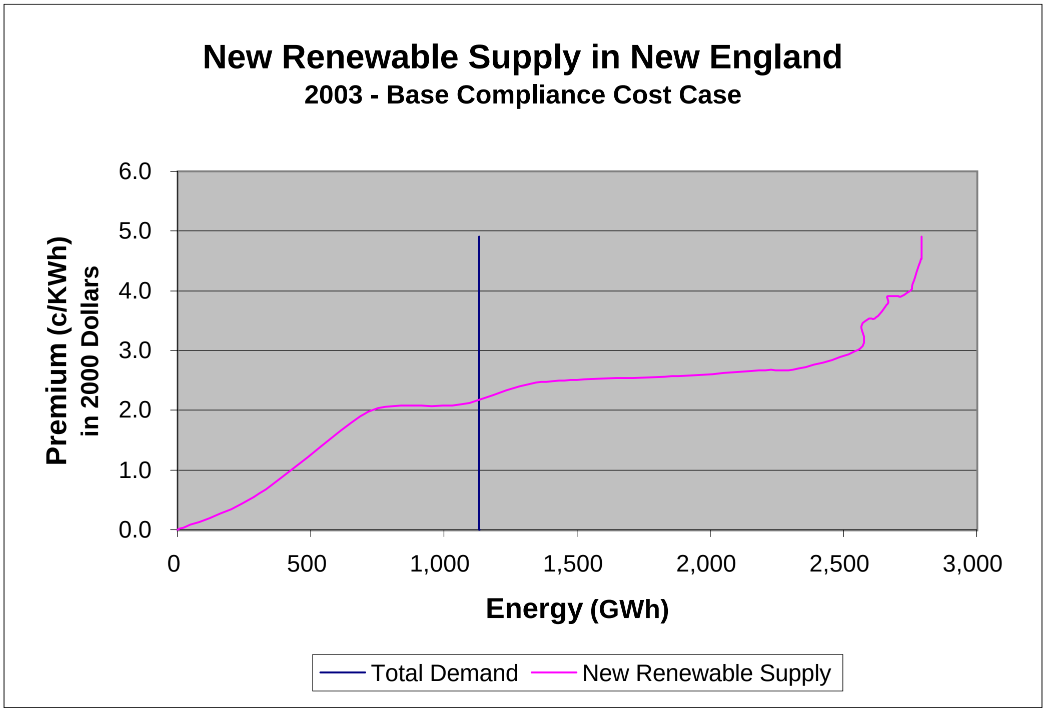
	High cost	Ave. cost	Low Cost
Percentage of capacity	20%	60%	20%

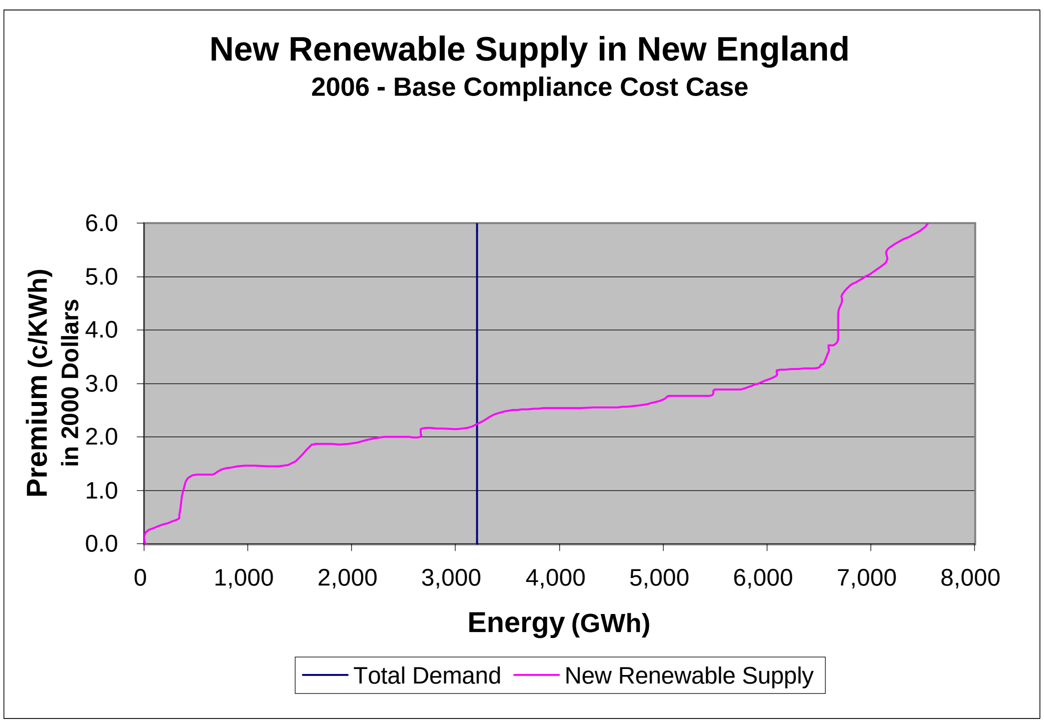
APPENDIX C
Base Case Supply and Demand

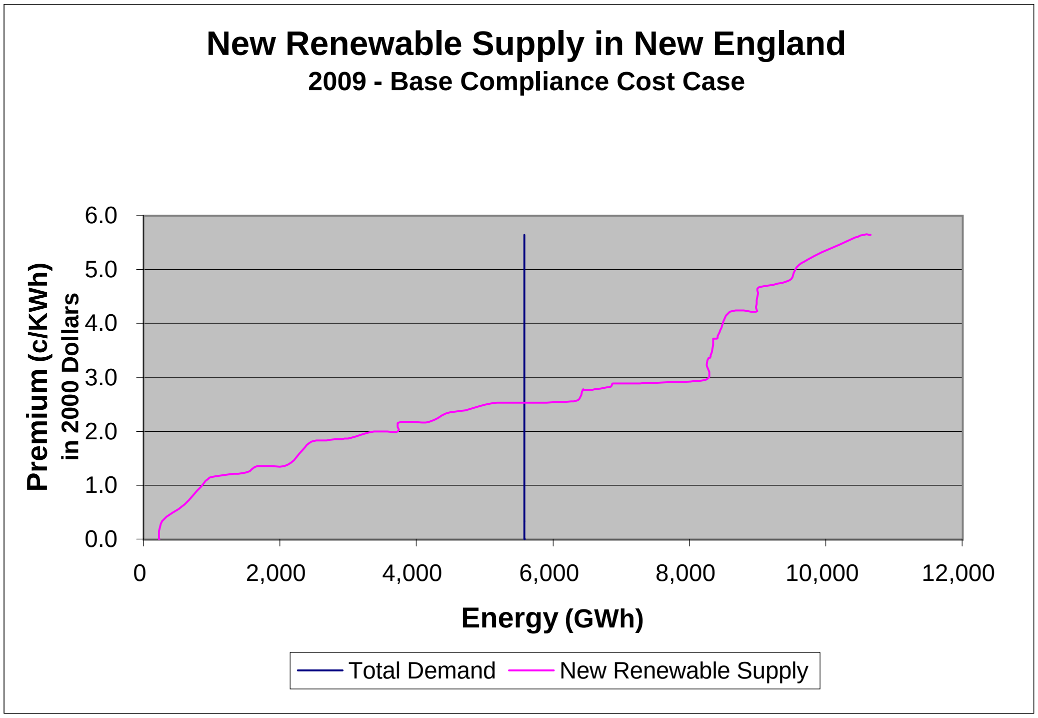
Graphs of Supply and Demand
for each Snapshot year

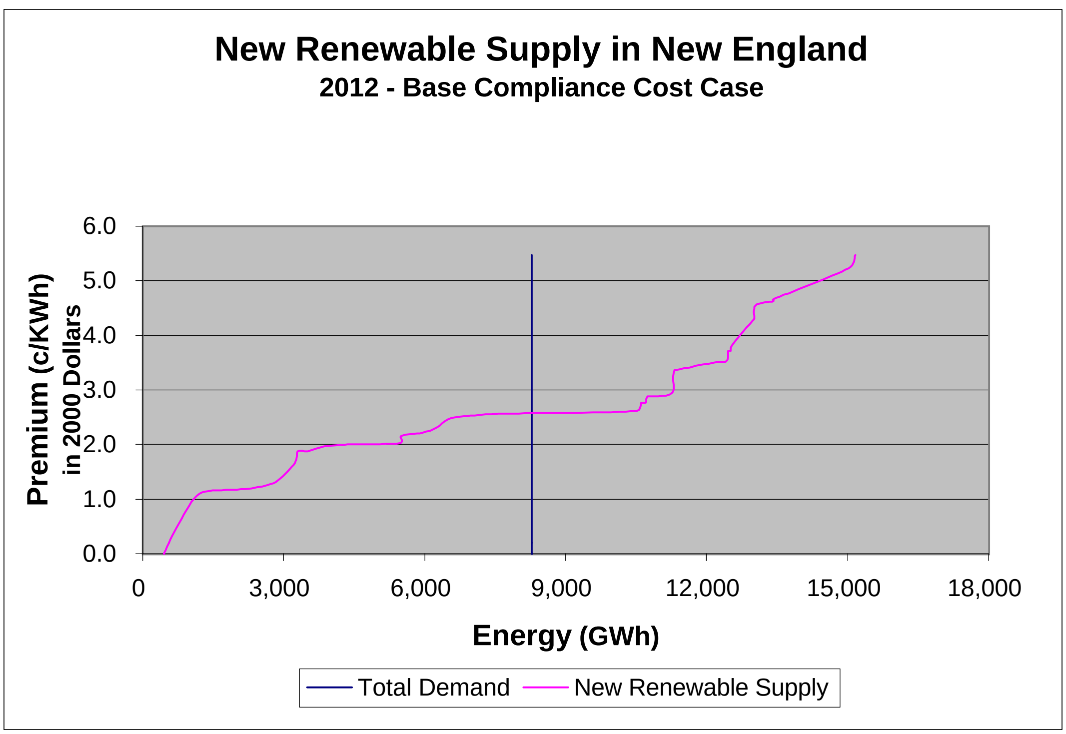
And

Supply Data, by Technology


New Renewable Supply in New England
2003 - Base Compliance Cost Case
Premium (c/KWh)
in 2000 Dollars
6.0
5.0
4.0
3.0
2.0
1.0
0.0
0
500
1,000
1,500
2,000
2,500
3,000
Energy (GWh)
Total Demand
New Renewable Supply


New Renewable Supply in New England
2006 - Base Compliance Cost Case
Premium (c/KWh)
in 2000 Dollars
6.0
5.0
4.0
3.0
2.0
1.0
0.0
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
Energy (GWh)
Total Demand
New Renewable Supply


New Renewable Supply in New England
2009 - Base Compliance Cost Case
Premium (c/KWh) in 2000 Dollars
6.0
5.0
4.0
3.0
2.0
1.0
0.0
0
2,000
4,000
6,000
8,000
10,000
12,000
Energy (GWh)
Total Demand
New Renewable Supply


New Renewable Supply in New England
2012 - Base Compliance Cost Case
Premium (c/KWh) in 2000 Dollars
6.0
5.0
4.0
3.0
2.0
1.0
0.0
0
3,000
6,000
9,000
12,000
15,000
18,000
Energy (GWh)
Total Demand
New Renewable Supply

Base Case Supply Curve

2003

Technology	Generation GWh	Price c/KWh
Generic Renewable Unit	-	0.000
Fuel Cell (high)	-	0.000
Fuel Cell (ave.)	-	0.000
Fuel Cell (low)	-	0.000
Bio/Gas Co-fire (high)	-	0.000
Bio/Gas Co-fire (ave.)	-	0.000
Bio/Gas Co-fire (low)	-	0.000
Repowered Bio (high)	-	0.000
Repowered Bio (ave.)	-	0.000
Repowered Bio (low)	-	0.000
Existing Bio (SCR)	-	0.000
Bio Gas (high)	-	0.000
Bio Gas (ave.)	-	0.000
Bio Gas (low)	-	0.000
Landfill gas (low)	287	0.546
Landfill gas (ave.)	669	1.840
Existing Bio (tuning)	778	2.056
Landfill gas (high)	1,065	2.099
Existing Bio (SNCR)	1,283	2.395
Bio/Coal Co-fire (low)	1,432	2.493
Bio/Coal Co-fire (ave.)	1,879	2.570
W(03)-1	2,183	2.672
Bio/Coal Co-fire (high)	2,332	2.699
W(03)-2	2,562	3.034
W(03)-3	2,568	3.410
W(03)-5	2,597	3.530
W(03)-4	2,618	3.534
W(03)-6	2,666	3.782
Wind (low)	2,666	3.858
W(03)-9	2,667	3.906
W(03)-8	2,701	3.906
W(03)-7	2,718	3.907
W(03)-10	2,757	4.028
Wind (ave.)	2,757	4.073
W(03)-12	2,790	4.527
W(03)-11	2,793	4.528
W(03)-13	2,794	4.903
Wind (high)	2,794	6.231
Bio Combusiton (low)	2,948	6.302
Bio Combusiton (ave.)	3,411	6.601
Bio Combusiton (high)	3,565	7.099

2003 Renewable Demand **1,132**

Marginal unit is highlighted in gray

Base Case Supply Curve

2006

Technology	Generation GWh	Price c/KWh
Fuel Cell (low)	5	(0.09)
Generic Renewable Unit	11	0.00
Existing Bio (SCR)	11	0.00
Fuel Cell (ave.)	26	0.23
Landfill gas (low)	332	0.46
Fuel Cell (high)	337	0.54
Bio/Gas Co-fire (low)	419	1.22
Bio/Gas Co-fire (ave.)	663	1.29
Bio/Gas Co-fire (high)	744	1.39
Small LFG (low)	977	1.46
Landfill gas (ave.)	1,385	1.47
Existing Bio (tuning)	1,604	1.83
W(06)-1	1,663	1.87
Landfill gas (high)	1,969	1.87
W(06)-3	2,314	2.00
W(06)-2	2,659	2.00
W(06)-4	2,676	2.16
Existing Bio (SNCR)	3,113	2.17
Bio/Coal Co-fire (low)	3,411	2.44
W(06)-5	3,758	2.52
Bio/Coal Co-fire (ave.)	4,651	2.57
Small LFG (high)	4,963	2.67
W(06)-6	5,053	2.77
W(06)-8	5,080	2.77
W(06)-7	5,171	2.77
Bio/Coal Co-fire (high)	5,468	2.77
W(06)-10	5,496	2.89
W(06)-9	5,727	2.89
Wind (low)	5,859	2.96
Small LFG (high)	6,092	3.15
W(06)-11	6,098	3.24
Wind (ave.)	6,493	3.30
W(06)-13	6,522	3.36
W(06)-12	6,543	3.36
W(06)-14	6,592	3.60
W(06)-18	6,594	3.72
W(06)-17	6,594	3.72
W(06)-16	6,628	3.72
W(06)-15	6,645	3.72
W(06)-19	6,685	3.83
W(06)-20	6,687	4.31
W(06)-21	6,720	4.54
W(06)-22	6,722	4.66
Repowered Bio (low)	6,796	4.83
Wind (high)	6,928	4.96
Repowered Bio (ave.)	7,151	5.27
Bio Gas (low)	7,169	5.53
Bio Combusiton (low)	7,478	5.86
Repowered Bio (high)	7,552	5.98
Bio Gas (ave.)	7,606	6.01
Bio Combusiton (ave.)	8,531	6.36
Bio Gas (high)	8,550	6.78
Bio Combusiton (high)	8,858	7.15

2006 Renewable Demand **3,206**

Base Case Supply Curve

2009

Technology	Generation GWh	Price c/KWh
Fuel Cell (low)	53	(0.56)
Fuel Cell (ave.)	210	(0.11)
Generic Renewable Unit	221	0.00
Existing Bio (SCR)	221	0.00
Fuel Cell (high)	274	0.34
Landfill gas (low)	600	0.65
Small LFG (low)	842	0.98
Bio/Gas Co-fire (low)	1,008	1.15
Bio/Gas Co-fire (ave.)	1,506	1.24
Bio/Gas Co-fire (high)	1,672	1.36
Landfill gas (ave.)	2,107	1.38
Small LFG (high)	2,429	1.78
Existing Bio (tuning)	2,650	1.83
Landfill gas (high)	2,977	1.87
W(06)-1	3,036	1.87
W(06)-3	3,381	2.00
W(06)-2	3,726	2.00
W(06)-4	3,742	2.16
Existing Bio (SNCR)	4,184	2.17
Small LFG (high)	4,425	2.32
Bio/Coal Co-fire (low)	4,723	2.39
Wind (low)	5,103	2.52
W(06)-5	5,449	2.52
Bio/Coal Co-fire (ave.)	6,343	2.57
W(06)-6	6,434	2.77
W(06)-8	6,460	2.77
W(06)-7	6,551	2.77
Bio/Coal Co-fire (high)	6,849	2.82
W(06)-10	6,877	2.89
W(06)-9	7,108	2.89
Wind (ave.)	8,247	2.96
W(06)-11	8,253	3.24
W(06)-13	8,282	3.36
W(06)-12	8,303	3.36
W(06)-14	8,352	3.60
W(06)-18	8,354	3.72
W(06)-17	8,354	3.72
W(06)-16	8,389	3.72
W(06)-15	8,405	3.72
W(06)-19	8,445	3.83
Repowered Bio (low)	8,595	4.22
Wind (high)	8,975	4.22
W(06)-20	8,977	4.31
W(06)-21	9,010	4.54
W(06)-22	9,012	4.66
Repowered Bio (ave.)	9,463	4.80
Bio Gas (low)	9,648	5.12
Bio Combusiton (low)	10,505	5.63
Repowered Bio (high)	10,655	5.64
Bio Gas (ave.)	11,210	5.78
Bio Combusiton (ave.)	13,779	6.32
Bio Gas (high)	13,964	6.71
Bio Combusiton (high)	14,821	7.31

2009 Renewable Demand	**5,584**

Base Case Supply Curve

2012

Technology	Generation GWh	Price c/KWh
Fuel Cell (low)	107	(0.94)
Fuel Cell (ave.)	428	(0.37)
Generic Renewable Unit	450	0.00
Existing Bio (SCR)	450	0.00
Fuel Cell (high)	557	0.20
Landfill gas (low)	907	0.78
Bio/Gas Co-fire (low)	1,164	1.06
Small LFG (low)	1,413	1.14
Bio/Gas Co-fire (ave.)	2,181	1.18
Landfill gas (ave.)	2,648	1.25
Bio/Gas Co-fire (high)	2,904	1.36
Small LFG (high)	3,236	1.67
W(06)-1	3,295	1.87
Existing Bio (tuning)	3,519	1.88
Landfill gas (high)	3,869	1.96
W(06)-3	4,214	2.00
W(06)-2	4,559	2.00
Wind (low)	5,484	2.02
W(06)-4	5,500	2.16
Existing Bio (SNCR)	5,947	2.22
Bio/Coal Co-fire (low)	6,244	2.31
Small LFG (high)	6,493	2.46
W(06)-5	6,840	2.52
Bio/Coal Co-fire (ave.)	7,734	2.57
Wind (ave.)	10,510	2.62
W(06)-6	10,601	2.77
W(06)-8	10,627	2.77
W(06)-7	10,718	2.77
W(06)-10	10,746	2.89
W(06)-9	10,977	2.89
Bio/Coal Co-fire (high)	11,275	2.95
W(06)-11	11,281	3.24
W(06)-13	11,310	3.36
W(06)-12	11,332	3.36
Wind (high)	12,257	3.51
Repowered Bio (low)	12,411	3.51
W(06)-14	12,459	3.60
W(06)-18	12,461	3.72
W(06)-17	12,462	3.72
W(06)-16	12,496	3.72
W(06)-15	12,513	3.72
W(06)-19	12,552	3.83
Repowered Bio (ave.)	13,012	4.30
W(06)-20	13,015	4.31
W(06)-21	13,048	4.54
Bio Gas (low)	13,429	4.63
W(06)-22	13,430	4.66
Bio Combusiton (low)	15,018	5.22
Repowered Bio (high)	15,171	5.48
Bio Gas (ave.)	16,314	5.54
Bio Combusiton (ave.)	21,078	6.20
Bio Gas (high)	21,458	6.91
Bio Combusiton (high)	23,046	7.66

2012 Renewable Demand	**8,276**