Economic Impacts and Potential Air Emission Reductions from Renewable Generation & Efficiency Programs in New England:

Final Report

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1.0 Introduction

1.1 Purpose and Scope

Synapse Energy Economics, Inc., (Synapse) has prepared this analysis to assist The Regulatory Assistance Project (RAP) in analyzing the impact of renewable generation projects and electric energy efficiency programs in New England. The analysis first covers new renewable generation that came on line during the period beginning with January 1, 2000 and ending December 31, 2004, including the effects of both their construction and their operation through the end of the study period at December 31, 2010. This initial analysis also includes the impact of New England electric energy efficiency programs from January 1, 2000, forward to the end of the study period, December 31, 2010. The first analysis for renewable generators is referred to as the "Phase I" analysis in the rest of this report. The Phase I analysis is intended to estimate the impact of certain state policies for renewable generation and electric energy efficiency from 2000 through 2004, but to include the on-going impacts of those policies through 2010.

In the energy efficiency portion of the study, we include the utility programs of the New England states, as well as the non-utility programs of those states that are funded by a system benefit charge (SBC) applicable to retail electricity sales. We include the activities of those programs as reported for each of calendar years 2000 through 2004. In addition, we assume that those programs will continue during the calendar years 2005 through 2010 and operate unchanged at their 2004 levels of expenditures and savings.

A second analysis, called the "Phase II" analysis was performed, as well. The Phase II analysis includes the impact of electric energy efficiency programs from the beginning of 2000 through the end of 2010, but its renewable generation aspect is expanded to include new renewable generation that came or is expected to come on line between January 1, 2005, and December 31, 2010, in addition to renewable generators included in Phase I as a result of New England renewable portfolio standard (RPS) requirements. In addition to specific, announced, RPS-eligible renewable generation units that are expected to come on line during 2005 through 2010, we included an additional amount of new generic renewable units sufficient to meet the requirements of the existing state RPS rules during that period.

We examine those new renewable generators, defined as a project eligible under the renewable generation definition of one or more New England states, entering commercial service on or after January 1, 2000.[1] We assume that those units will operate at current levels through December 31, 2010, except for a few units that ceased operation prior our

[1] We are aware of several projects, especially run-of-river hydro units eligible for the Connecticut RPS, under way in New England to convert or upgrade new or pre-existing generators to provide more renewable power or to convert to production of renewable power for sale in New England markets. Those projects are not included in our study, but an equivalent amount of new generic units are included.

analysis, and report the estimated economic impacts and potential air emission reductions of the study units through that date.

In the energy efficiency portion of the study, we include the utility programs of the New England states, as well as the non-utility programs of those states that are funded by a system benefit charge (SBC) applicable to retail electricity sales. We include the activities of those programs as reported for each of calendar years 2000 through the last year of available data.. In addition, we assume that those programs will continue until 2010. Where savings or expenditure data are not available, we used assumptions derived from the best available information to project future energy efficiency program outlays and achievement through 2010. Our analysis is intended to estimate the impact of certain state policies for renewable generation and electric energy efficiency from 2000 through 2010, including the on-going impacts of those policies through 2010.

1.2 Overview of Methods

Our analysis of economic impacts relied on input data collected from the states as part of this study, as well as Synapse data on the investment and operating costs and operational characteristics of the relevant types of renewable generation. Electric efficiency (EE) program data used in this analysis include annual expenditures by program and annual electric energy savings. Both types of data were derived from efficiency program reports for the six New England states and additional information obtained from Commission and Energy Office staff in the states.

Most of the Synapse data on generic renewable units came from our recent study of renewable generation costs in New England performed for the Vermont Public Service Board. Since the eligible projects are not utility-owned, little public data exists on their construction and operating costs. Generic input data and assumptions were developed to represent hydro, wind, landfill gas, biomass, solar, and fuel cell projects relevant to the study period. Synapse data characterizing the fuel mix of ISO-NE's generation and variable operation and maintenance (O&M) costs were used to model avoided costs.

Economic impacts were estimated using the IMPLAN model. IMPLAN is a widely used input-output economic model, available with data for each state. We used a data set that combined the six states in New England into a single regional economy.

Potential air emission impacts were estimated using Synapse and ISO-NE data that characterizes the marginal emissions of ISO-NE generation. That data was used to estimate the potential air emission reductions each year due to the output of the renewable generation and electric efficiency program savings included in the study.

1.3 Limitations

This study does not address potential changes in various types of input data, including but not limited to marginal fuel mix and emission rates, avoided costs, productivity improvements at existing units, productivity improvements in energy efficiency programs, potential export business (or reduced import business) generated by growing local renewable or efficiency businesses, benefits from reduced volatility or clearing prices due to reduced traditional generation and associated fuel demands (including clearing price and volatility reductions for all fossil fuel users), or details of inter-state trade within New England.

Due to the linear nature of the IMPLAN model, the study does not consider possible changes in industry use of labor, capital, fuel or intermediate goods as demand changes. In particular, the model assumes that productivity of labor and other factor inputs is constant. To the extent that labor productivity continues to increase, reflecting that trend would reduce the labor impacts, both for increased spending on energy efficiency and renewable energy and for reduced output in the electric utility and fossil fuel sectors.

2.0 Data Collection

2.1 Renewable Generation Projects

Renewable Generation Output

We identified existing and planned RPS-eligible generators from the 2003 NEPOOL GIS "GIS Generators" public reports, from "RPS-Qualified New Renewable Generation Units" on the Massachusetts Division of Energy Resources (DOER) website (http://www.mass.gov/doer/rps/approved.htm), from the Maine Public Utility Commission's *CEP Annual Report for Calendar Year 2002*, and from *CT RPS Generator Application* on the Connecticut Department of Public Utility Control's website (http://www.state.ct.us/dpuc/database.htm).

We obtained limited generation data for some units from correspondence with staff at the Massachusetts DOER, who compiled the information from compliance reports, from the Maine PUC's *CEP Annual Report for Calendar Year 2002*, from the EIA Form 906 2002 Monthly Reports, from a report labeled "CT Generation" found on the electricity sector working group page of the CT Climate Change Stakeholder Dialogue at http://www.ccap.org, as well as the EPA EGRID database. For units and years in which generation data was not available, we estimated generation levels using unit capacity as listed in the 2003 Forecast Report of Capacity, Energy, Loads and Transmission (CELT report) and a generic capacity factor. These capacity factor assumptions are listed in Table 2.1. Biomass refers to wood steam generators, LFG refers to landfill gas, PV refers to photovoltaic systems, and MT refers to one biodiesel-based microturbine unit included in our analysis. Our assumptions on wood steam plants are more discussed in "Phase II Analysis" and "Renewable Generation Cost" sections below.

Table 2.1 Capacity Factors

Wind	Hydro	Biomass	Landfill Gas	PV	Fuel Cell	MT
28%	50%	80%	90%	16%	85%	90%

Phase I Analysis

The Phase I analysis includes new renewable generation plants that went on line during the period beginning January 1, 2000 and ending December 31, 2004. Table 2.2 presents specific generation additions each year by fuel. We assume that those renewable generation facilities continue operating until December 31, 2010, except for certain specific facilities that discontinued operation prior to this writing. With the data and assumption for such renewable generation, we estimated the total generation output for the renewable generation in the Phase I analysis shown at Table 2.3. Note that generation by wood steam facilities starting from 2005 is due to one large wood steam unit that started operating December 31, 2004. Also, wind power generation decreased in 2005 to 2010 because two wind facilities stopped operating in 2004.

Table 2.2. Phase I Specific Capacity Additions by Fuel Type (MW)

	2000	2001	2002	2003	2004	Total
LFG	8.7	2.8		5.6	14.7	31.8
Hydro	3.9	3.1	1.9	4.0		12.9
Biomass					25.9	25.9
Wind	0.3	0.7				1.0
NGFC			0.6	0.7		1.3
PV	0.1				0.03	0.14
Total	13.0	6.6	2.5	10.3	40.6	72.9

Table 2.3. Phase I Generation Output by Fuel Type (MWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
LFG	28,735	54,035	70,546	104,536	217,771	230,434	230,434	230,434	230,434	230,434	230,434
Hydro	12,804	28,524	36,323	46,084	102,072	102,072	102,072	102,072	102,072	102,072	102,072
Biomass	0	0	0	0	0	178,031	178,031	178,031	178,031	178,031	178,031
Wind	579	577	1,398	2,196	2,196	1,619	1,619	1,619	1,619	1,619	1,619
PV	156	156	156	156	727	726	726	726	726	726	726
NGFC	0	0	2,766	5,810	9,308	9,308	9,308	9,308	9,308	9,308	9,308
Total	42,274	83,292	111,189	158,782	332,072	522,189	522,189	522,189	522,189	522,189	522,189

Phase II Analysis

Our Phase II analysis differs from the Phase I analysis only in that it includes new renewable generation that will come online between January 1, 2000 and December 31, 2010. This includes both specific new facilities known to us and an additional amount of generic new additions sufficient to meet the existing RPS requirements through 2010.

Several renewable projects that came or will come on line and are eligible for MA RPS in or after 2005 were identified. Table 2.4 presents the capacity additions for Phase II analysis. Information regarding the new renewable projects is obtained from MA DOER's website as follows:

- two wind projects in 2005
- two landfill gas project in 2005
- one biodiesel-based microturbine project in 2005
- one wood steam boiler project in 2005
- six biomass facilities using fluidized bed that are likely to be in operation in 2006 or 2007 are treated as conventional wood steam boilers because data on fluidized bed biomass technologies is not yet readily available in sufficient detail to conduct in-depth economic and environmental analysis.

There are also four biomass facilities (two re-tooled biomass combustion plants with fluidized bed; one bio-oil; and one anaerobic digestion projects) that we identified in MA DOER's list but did not include in our study due to lack of sufficient data on those technologies such as total capital and O&M costs, details of such costs (e.g. share of generator, building and road construction, installation labor, interconnection-related costs in the total capital costs) and in service date.[2]

In addition to these specific projects, we assumed a sufficient amount of new generic renewable generation plants would come on line after 2004 in order to meet RPS goals in Massachusetts, Connecticut (Class I), and Rhode Island. Such plants were assumed to be divided among wind, solar, landfill gas, run-of-river hydro, fuel cell, and biomass. Table 2.5 presents the generic capacity additions (as well as the capacity of the Phase I units shown in Table 2.2) and Table 2.6 presents their generation output based on specific and generic capacity factor values (including the output of the Phase I units shown in Table 2.3).

As mentioned above, most of the specific biomass projects eligible for Massachusetts RPS use fluidized bed combustor technology, and we are aware that such advanced biomass plants with lower emission will be likely candidates in MA and CT Class I RPS markets in the next five years.[3] Anticipating that advanced biomass technologies would include fluidized bed combustor, fluidized bed gasifier, and the use of those technologies for repowering or retrofitting existing biomass, coal, and natural gas-fired plants, we assume lower emissions for new generic biomass units, consistent with those advanced technologies. However, estimating the capital and operating cost assumptions for those new generic units poses difficulties. Newly built units are likely to be more expensive than new conventional wood steam units, but repowering existing steam units with such technologies is likely to be less expensive. The capital costs of new conventional wood steam units (around $1735/kW) is about the midpoint of the capital costs of new fluidized bed gasifier or high pressure gasification units (around $2500 to $3000/kW) and repowering existing steam plants (around $300 to $600/kW). Therefore, we use $1735/kW as a rough representation for the capital cost of a mix of those new technologies.[4] We applied O&M costs associated with conventional steam plants to all new biomass plants.

[2] These capital and O&M cost details are required to conduct in-depth economic analysis by IMPLAN.

[3] Conventional biomass steam plants are not eligible for MA and CT I RPS due to their stricter standards.

[4] Bob Grace and LaCapra Associates, 2004, *RGGI Renewable Energy Modeling Assumptions* for the cost of advanced biomass technologies; California Energy Commission, 2002, *Biomass Cofirng with Natural Gas in California* and Energy Products of Idaho, 2001, *Repowering Options: Retrofit of Coal-Fired Power Boilers using Fluidized Bed Biomass Gasification* for the cost of biomass co-firing.

Table 2.4. Phase II Specific Capacity Additions by Fuel Type (MW)[5]

Fuel	2000	2001	2002	2003	2004	2005	2006	2007	Total
LFG	8.7	2.8		5.6	14.7	6.3			38.1
Hydro	3.9	3.1	1.9	4.0					12.9
Biomass					25.9	8.6	70.9	100.3	205.7
Wind	0.3	0.7				4.1			5.1
PV	0.1				0.03				0.1
NGFC			0.6	0.7					1.3
BDMT						0.03			0.0
Total	13.0	6.6	2.5	10.3	40.6	19.0	70.9	100.3	263.1

Table 2.5. Combined Phase I and II Capacity Additions by Fuel Type (MW)[6]

Fuel	2005	2006	2007	2008	2009	2010	Total
LFG	34.0	33.0		23.0	15.0	20.0	125.0
Hydro	7.0	2.0		11.0	10.7	3.3	34.0
Biomass	43.0	15.0	1.0	13.0	18.0	27.0	117.0
Wind		20.0	3.0	114.0	134.0	94.0	365.0
PV	0.2	0.4	0.1	1.3	1.2	2.4	5.6
NGFC	15.0	15.0		20.0	20.0	20.0	90.0
Total	99.2	85.4	4.1	182.3	198.9	166.7	736.6

Table 2.6. Combined Phase I and II Generation Output by Fuel (MWh)

Fuel	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
LFG	28,735	54,035	70,546	104,536	217,771	532,550	805,545	805,545	987,374	1,105,137	1,262,8
Hydro	12,804	28,524	36,323	46,084	102,072	132,732	141,492	141,492	189,804	236,538	250,99
Biomass	0	0	0	0	0	509,757	895,239	1,851,541	1,942,895	2,068,789	2,258,0
Wind	579	577	1,398	2,196	2,196	4,809	60,682	68,041	348,426	676,335	906,89
PV	156	156	156	156	727	1,007	1,567	1,707	3,535	5,211	8,575
NGFC	0	0	2,766	5,810	9,308	120,998	232,688	232,688	382,016	530,528	679,44
BDMT	0	0	0	0	0	187	223	223	223	223	223
Total	42,274	83,292	111,189	158,782	332,072	1,302,039	2,137,436	3,101,237	3,854,272	4,622,761	5,366,9

[5] NG(FC) is natural gas-based fuel cells and BD(MT) is biodiesel-based microturbine. Natural gas-based fuel cells are eligible units in some RPS rules. Some such rules encourage NG(FC) units due to their significantly lower NOx and SO2 emissions compared to central power plants and also because they are viewed as a bridge technology to fuel cells that rely on hydrogen, a particularly clean fuel that may be able to be produced and stored from intermittent renewable electricity sources.

[6] No generic BDMT units were included in Phase II, so no assumptions were developed. The BDMT generation in Table 2.6 is from one specific biomass MT unit.

Renewable Generation Costs

We based the capital and operating costs of different renewable generating technologies on estimates from economic analyses of the Massachusetts RPS and proposed renewable standards in New York and Vermont, as well as cost characterizations from EIA, EPA, and Massachusetts Technology Collaborative.[7] These costs were divided into various IMPLAN model sectors representing the different economic activities conducted in the region, such as different types of goods and services produced. We allocated the costs to these categories using capital and O&M cost breakdowns in various studies such as the Department of Energy's Renewable Technology Characterizations, and our professional judgment. Our renewable technology cost estimates and their allocations to different cost categories are shown in Tables 2.7 and 2.8. These costs have been converted to 2001 dollars.

Table 2.7. Capital Cost Assumptions

Fuel	Total Capital Cost (2001$/kW)	Turbine/ Generator Equipment	Building Construction	Road Construction	Intercon-nection	Installation Labor	Other Costs
Wind	1,117	60%	5%	10%	5%	10%	10%
Hydro	2,416	37%	37%	3%	3%	10%	10%
Biomass	1,735	60%	5%	10%	5%	10%	10%
LFG	1,950	65%	5%	0%	5%	15%	10%
PV	5,500	70%	5%	0%	10%	5%	10%
FC	4,424	70%	5%	0%	10%	5%	10%
MT	3,500	61%	5%	0%	5%	15%	14%

[7] Smith, Douglas, Karlynn Cory, Robert Grace, and Ryan Wiser 2000. *Massachusetts Renewable Portfolio Standard Cost Analysis Report,* prepared for the Division of Energy Resources; New York State Department of Public Service, New York State Energy Research and Development Authority, *Sustainable Energy Advantage*; LaCapra Associates 2003, *New York Renewable Portfolio Standard: Cost Study Report*, July; Synapse Energy Economics, Inc., 2003, *Potential Cost Impacts of a Vermont Renewable Portfolio Standard*, prepared for the Vermont Public Service Board; U.S. Energy Information Administration 2004, *Assumptions to the Annual Energy Outlook 2004*; U. S. Environmental Protection Agency, *Catalogue of CHP Technologies*; Massachusetts Technology Collaborative, *Green Building Initiatives: Completed Feasibility Studies*, available at http://www.mtpc.org/RenewableEnergy/green_buildings/green_buildings_projects.htm.

Table 2.8. O&M Cost Assumptions

	Total O&M Cost (2001$/MWh)	Labor	Equipment	Property Taxes	Insurance	Professional Services
Wind	12	60%	12%	15%	1%	12%
Hydro	20	60%	12%	15%	1%	12%
Biomass	33	55%	25%	10%	1%	9%
LFG	15	50%	27%	10%	1%	12%
PV	9	69%	5%	15%	1%	10%
Fuel Cell	3	55%	25%	10%	1%	9%
MT	12	55%	25%	10%	1%	9%

Note: Biomass O&M Cost includes fuel cost component equal to $30/MWh.

Avoided Fuel and O&M Costs

Since assumptions for avoided fuel and avoided O&M costs are used to measure economic impacts of renewable generation and energy efficiency projects, we will summarize their sources here. We estimated the avoided fuel cost from 2000 to 2010, using avoided marginal generation fuel mix and fuel price data. (See Tables 2.9(a) and 2.9(b).) The avoided marginal fuel mix data from the year 2000 to 2003 were provided by NEPOOL. After those years, we assumed the trend in the year 2003's avoided fuel mix continue to 2010.

Table 2.9(a) 2000 to 2003 Marginal Generation by Unit Type (GWh)

	2000	2001	2002	2003
Coal	281	346	303	12
Heavy Oil	1,201	1,594	973	587
Hydro	0	0	0	0
Jet Fuel	0	6	0	0
Light Oil	0	5	0	0
Methane	0	0	0	0
Mix	2,130	563	501	344
Natural Gas	768	1,766	2,555	3,402
Nuclear	0	0	0	0
Trash	0	23	17	4
Wood	12	77	31	20

Source: NEPOOL, February 4, 2005. "Mix" represents units burning multiple fuels.

Table 2.9(b) Summary of Avoided Fuel Cost Components (Nominal $/MWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Coal	1.03	1.39	1.30	0.05	0.05	0.05	0.05	0.06	0.06	0.05	0.05
Heavy Oil	11.43	13.41	8.47	6.23	7.17	7.12	6.29	5.80	5.62	5.52	5.53
Mix	19.17	4.29	3.98	3.64	4.00	4.14	3.88	3.67	3.60	3.47	3.42
Natural Gas	6.20	10.95	17.94	35.87	37.15	40.42	40.55	39.41	39.09	36.86	35.82
Trash	0.00	0.16	0.12	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Wood	0.06	0.36	0.15	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.10
Total	37.9	30.6	32.0	45.9	48.5	51.9	50.9	49.1	48.5	46.0	44.9

Delivered fuel prices are New England specific and derived or obtained from several sources. (See Table 2.10.) Wood and trash prices are based on Synapse's RPS study. Natural gas prices from 2005 to 2010 are derived from NYMEX future prices at wellhead level and EIA's assumption on the cost of fuel delivery. Other fuel costs are obtained from EIA's *Annual Energy Outlook 2005* and *Cost and Quality of Fuels for Electric Plants 2001*.

Table 2.10. Delivered Fuel Prices (Nominal Dollars/MMBtu)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Coal	1.53	1.67	1.79	1.84	1.88	1.88	1.95	1.96	1.98	1.83	1.87
Heavy Oil	3.98	3.59	3.81	4.64	5.34	5.30	4.68	4.32	4.18	4.11	4.11
Mix	4.16	3.51	3.86	5.15	5.65	5.84	5.48	5.18	5.08	4.89	4.83
Natural Gas	4.43	3.40	3.94	5.91	6.12	6.65	6.68	6.49	6.44	6.07	5.90
Trash	2.00	2.05	2.08	2.11	2.13	2.13	2.21	2.22	2.25	2.08	2.11
Wood	2.00	2.05	2.08	2.11	2.13	2.13	2.21	2.22	2.25	2.08	2.11

Note: Mix fuel price is assumed to contain 60 % heavy oil and 40% natural gas and to be used for duel fuel generators.

We estimated avoided O&M costs using EIA data assumptions, implicit price deflators and the marginal fuel mix. Because the EIA assumptions are for new units, which typically have lower O&M costs than existing units, our avoided O&M estimates are conservatively low. The nominal dollar amounts are shown in Table 2.11. They were converted to 2001 dollars internally by the IMPLAN model using deflators specific to the industry sector providing each good or service.

Table 2.11 Avoided O&M Costs (Nominal Dollars/MWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Avoided O&M Cost	2.50	2.40	2.30	2.25	2.20	2.24	2.27	2.31	2.35	2.38	2.42

Renewable Energy Certificate Prices

We obtained spot market prices of RPS-compliant Renewable Energy Certificates (RECs) from Evolution Markets. Spot-market prices for RECs that meet the Massachusetts and Connecticut Class I standards are believed to be significantly higher than the cost premium that an electric supplier would incur for a long-term contract with a renewable generator. However, little information about such contracts is available in New England. Thus, we have used only the spot market prices to estimate the renewable price premium, which likely overstates the actual RPS rate impact. For 2005 and later, we used values in the range of the Evolution Markets REC futures prices for 2004-2006. The values used were $40/MWh for Massachusetts, Rhode Island, and Connecticut (Class I) and $0.75/MWh for Connecticut (Class II) and Maine.

2.2 Electric Energy Efficiency Programs

Electric efficiency (EE) program data used in this analysis includes annual expenditures by program and annual electric energy savings. Both data series were derived from efficiency program reports for the six New England states with additional information obtained from Commission and Energy Office staff in the states.

Expenditures

Table 2.12 shows the New England states' total expenditures by program for each year from 2000 through the last year of available data with the following adjustments or assumptions:

New Hampshire

- Only annual totals were available in 2000, 2001, and 2002; they were pro-rated among the program categories using percentages from 2003, where program detail was available.

Maine

- For 2000 to 2002, and for the sub-class level in 2004, Maine data was prorated using our judgment.
- Annual projected total outlays are available from 2005 to 2009. However, since only annual total outlays are available for C&I programs, they were pro-rated among the C&I program categories using percentages from 2004 where program detail is available.
- 2000-2002 Program expenditures are 20% of those reported by utilities on Form 861, since, according to the PUC, 80-90% of those expenditures were used to pay

down earlier CMP Power Partners Program contracts that resulted in minimal new savings. 2003-2010 expenditures also do not include that portion of public benefit funds used to pay down Power Partners contracts, or funds transferred to the Maine General fund in FY 2003 and 2004.

Massachusetts

- Data for 2003 and 2004 was based on state projections.

Connecticut

- Data for 2004 and 2005 was based on state projections.
- Projected annual total expenditures are available from 2006 to 2010. They were pro-rated among program categories using percentage from 2005 where program expenditure detail is available.

Rhode Island

- Data for 2004 and 2005 was based on state projections.

Vermont

- Total expenditures for 2004 and 2005 were based on state projections. They were pro-rated among program categories using percentage from 2003 where program expenditure detail is available.

Projections of program expenditures were made by applying an inflation adjustment to the last year of data or state projections available. New England-wide totals were computed by summing individual program data and projections.

The amounts in Table 2.12 are the nominal dollar values reported in historical years. As explained elsewhere, the projected outlays for later years were held constant in 2001 dollars, but are shown here in nominal dollars to allow comparison with the historical trend. They were converted to 2001 dollars internally by the IMPLAN model using deflators specific to the industry sector providing each good or service. The total outlay over the entire study period is about $2,600,000,000 in 2001 dollars.

Electricity Savings

Table 2.13 shows the annualized electricity savings, at the generation level, delivered by the measures installed during that year from the programs.[8] The actual or projected savings reported by states, except Vermont, are estimated at customer level in their publications. Savings in Vermont are reported at power generation level. We used a nine

[8] The annualized savings of an efficiency measure represents the amount of electricity that the measure saves when in place and operating for a full year.

percent energy loss in transmission and distribution line to adjust the customer level savings to generation level savings.[9]

Table 2.12. Electric Efficiency Program Outlays in New England (000's of Nominal Dollars)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential											
New Construction	8,288	12,574	8,961	9,213	10,013	10,599	10,543	10,768	10,998	11,354	11,596
In-Home Services/Retrofit	38,314	47,269	43,317	38,653	39,925	41,710	41,690	42,603	43,538	44,896	45,879
Products and Services	31,942	32,871	27,926	22,879	36,143	41,264	40,620	41,912	42,719	44,653	45,445
Other	4,839	6,335	3,668	6,965	4,140	4,636	4,479	4,543	4,607	4,778	4,861
Subtotal	83,383	99,049	83,872	77,710	90,220	98,209	97,334	99,825	101,862	105,682	107,780
Commercial and Industrial											
New Construction	42,160	40,542	43,468	37,968	46,879	49,873	49,187	50,280	51,337	53,206	54,280
Retrofit/Products and Services	94,096	89,425	79,483	68,239	86,460	90,538	88,715	91,520	93,350	97,274	99,188
Other	7,956	7,329	4,512	12,033	7,016	5,933	5,458	5,518	5,580	5,878	5,942
Subtotal	144,212	137,295	127,463	118,240	140,355	146,344	143,360	147,317	150,266	156,357	159,410
Other	15,664	18,640	29,837	26,683	13,452	16,886	14,688	14,700	14,702	15,807	15,851
Total	243,336	255,065	241,246	222,633	244,027	261,439	255,381	261,842	266,830	277,845	283,041

Actual and projected savings data were obtained from several sources including state agency's reports, correspondence with state agency's staff, one electric utility (Narragansett Electric for Maine), third party administrators (Efficiency Vermont and Efficiency Maine), and EIA Form 861 reports (for New Hampshire and Maine). Following adjustments are made to complete energy savings data from 2000 to 2010 in Table 2.13:

- For years when program specific savings data for Residential Sector are not available (for Connecticut for 2000 to 2004 and Maine for 2000 to 2002), they were estimated by applying weighted average $/kWh savings performance of each program from other states.
- For years when program specific savings data for C&I Sector is not available (for Connecticut and Maine), they were estimated to be proportional to available

[9] Nine percent is a national average figure (EIA, February 2005, *Monthly Energy Review*) for annual average transmission and distribution losses. This number is a conservative estimate given that energy efficiency programs reduce marginal generation that contributes to higher than average line loss.

program expenditures because \$/MWh performance does not differ significantly among C&I programs unlike residential programs.

- For years when savings data is not available but expenditure data is available (for Connecticut for 2006 to 2010, for Maine for 2005 to 2010, and for Vermont for 2004 to 2005), savings were estimated by adjusting the preceding year's savings by the ratio of each year's expenditures to the preceding year's expenditures, discounted by an inflation rate.
- For years when official projections on expenditures are not available, future program expenditures are projected to increase by a constant inflation rate each year and during those years, savings are held constant.

Table. 2.13. Annualized Electric Efficiency Program Savings (MWh) at Generation Level

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential											
New Construction	2,668	3,734	3,916	3,078	4,864	7,066	6,672	6,625	6,579	6,672	6,625
In-Home Services/Retrofit	56,467	57,847	62,680	50,401	47,759	57,846	55,353	55,056	54,766	55,354	55,057
Products and Services	126,630	175,992	143,597	93,176	154,655	194,980	181,229	179,590	177,991	181,231	179,592
Other	3,523	5,769	3,003	842	955	0	0	0	0	0	0
Subtotal	189,288	242,573	213,196	147,496	208,233	269,515	255,178	254,823	253,059	257,620	255,637
Commercial and Industrial											
New Construction	145,480	163,262	144,510	157,674	155,292	178,628	168,181	166,936	165,721	168,182	166,937
Retrofit/Products and Services	313,514	376,556	301,553	304,495	329,336	353,379	332,606	330,131	327,715	332,609	330,134
Other	19,813	38,664	25,074	11,302	19,752	3,279	2,722	2,656	2,591	2,722	2,656
Subtotal	478,807	579,581	471,137	473,471	504,380	553,074	520,803	520,421	516,806	526,103	522,316
Other											
Total	668,095	822,154	684,333	620,967	712,614	822,589	775,981	775,245	769,865	783,723	777,953

Table 2.14 shows the total electric energy savings in each year from the efficiency measures installed in that year and the prior years beginning with 2000. We assume that efficiency measures are installed at a constant pace throughout the year and end their contributions at a constant pace throughout the final year of their measure life. Therefore, we assume only one-half the annualized savings occurs in the installation year and the same amount in the year after the end of the average measure life. So, for example, the savings in 2002 for a program is the annualized savings delivered by the program in 2000 and 2001, plus one-half the annualized savings delivered in 2002.

Table. 2.14. Annual Accumulated Efficiency Program Savings (MWh) at Generation Level

Total New England	2000	2001	2002	2003	2004
Residential					
New Construction	1,334	4,535	8,360	11,858	15,828
In-Home Services/Retrofit	28,234	85,391	145,654	202,194	251,274
Products and Services	63,315	214,626	374,421	492,807	616,723
Other	1,761	6,407	10,793	12,716	13,614
Subtotal	94,644	310,575	538,459	718,806	896,670
Commercial and Industrial					
New Construction	72,740	227,111	380,997	532,089	688,572
Retrofit/Products and Services	156,757	501,793	840,847	1,143,871	1,460,786
Other	9,906	39,145	71,014	89,202	104,729
Subtotal	239,404	768,598	1,293,957	1,766,260	2,255,186
Other	-	-	-	-	-
Total	334,048	1,079,172	1,832,416	2,485,066	3,151,856

Total New England	2005	2006	2007	2008	2009	2010
Residential						
New Construction	21,794	28,663	35,311	41,913	48,539	55,188
In-Home Services/Retrofit	304,077	360,677	415,881	470,792	525,852	581,058
Products and Services	791,540	979,645	1,160,054	1,338,845	1,518,456	1,698,868
Other	14,091	14,091	14,091	14,091	12,330	10,569
Subtotal	1,135,544	1,397,891	1,652,892	1,906,833	2,160,411	2,415,278
Commercial and Industrial						
New Construction	855,533	1,028,937	1,196,495	1,362,823	1,529,775	1,697,335
Retrofit/Products and Services	1,802,144	2,145,137	2,476,505	2,805,428	3,135,591	3,466,962
Other	116,244	119,245	121,934	124,557	127,213	129,902
Subtotal	2,783,913	3,320,851	3,841,463	4,360,077	4,881,532	5,405,741
Other	-	-	-	-	-	-
Total	3,919,457	4,718,742	5,494,355	6,266,910	7,041,942	7,821,019

3.0 Economic Impact Methods and Results

3.1 Methods and Assumptions

Impacts on the New England economy from renewable generation and electric energy efficiency programs were estimated using the IMPLAN model configured as a single region containing the six New England states. The IMPLAN (IMpact analysis for PLANning) economic impact model allows us to measure both direct and secondary impacts of expenditures for the various goods and services demanded in the construction and operation of renewable generation plants and the delivery of energy efficiency programs. Data used for this study were developed using data and assumptions described in Section 2, above.

IMPLAN is an input-output (I/O) economic model. It estimates the interactions among the sectors of the regional economy, as well as indirect and induced effects via secondary purchases by those suppliers, as well as household purchases by the employees of all those industries and businesses and purchases by government.

I/O analysis traces the flow of goods and services, income, and employment among related sectors of the economy. In an I/O model, a change in the final demand for a product or service causes that sector to buy other goods and services from other sectors, which in turn purchase inputs from other industries. All of these sectors purchase additional labor, too. The additional employees purchase more goods and services. The job of the model is to compute the eventual sum of all of these purchases cycling through the economy.

IMPLAN (IMpact analysis for PLANning) is one of the most widely used I/O models. Originally developed for the USDA Forest Service in 1979, IMPLAN uses national accounts data and economic survey data from each region to build regional I/O models and forecasts regional economic impact based on those models.

Renewable Generator Construction

The impact on the New England economy of renewable generator construction in the years 2000 through 2010 was estimated using the construction cost data given above and the construction level data shown in Table 3.1. The Installation Labor amounts shown in Table 2.2 were proportionally allocated to the other cost categories listed in that table for allocation economic sectors listed in Table 3.2.

Renewable Generator Operation

Analyzing the impact on the New England economy of renewable generator operation is much more complex that analyzing the impacts of the construction of those units. This task includes modeling reduced purchases of fossil fuels, collection from consumers and payment to generators of the costs for renewable energy credits (RECs), new operation and maintenance (O&M) expense for the renewable generators, and decreased operation and maintenance expense for existing generation. Our approach to representing these events within IMPLAN's modeling structure divides the effects into three pairs of corresponding increases and decreases of outlays in the economy.

Table 3.1. Renewable Generator Construction Level (MW)

Unit Type	2000	2001	2002	2003	2004
Wind	0.32	0.66	--	--	--
Landfill Gas IC	8.7	2.80		5.60	14.68
Run-of-river Hydro	3.88	3.14	1.88	4.00	--
Fuel cells		--	0.6	0.65	--
PV	0.11	--	--	--	0.03
Wood steam	--	--	--	--	25.85
MT	--	--	--	--	--
Total Additions	13.01	6.60	2.48	10.25	40.56
Cumulative Additions	13.01	19.61	22.10	32.35	72.90

Unit Type	2005	2006	2007	2008	2009	2010
Wind	4.08	20.00	3.00	114.00	134.00	94.00
Landfill Gas IC	40.28	33.00	--	23.00	15.00	20.00
Run-of-river Hydro	7.00	2.00	--	11.00	10.70	3.30
Fuel cells	15.00	15.00	--	20.00	20.00	20.00
PV	0.20	0.40	0.10	1.30	1.20	2.40
Wood steam	51.6	85.90	101.30	13.00	18.00	27.00
MT	0.03	--	--	--	--	--
Total Additions	118.19	156.30	104.4	182.3	198.9	166.7
Cumulative Additions	191.09	347.39	451.79	634.09	832.99	999.69

Table 3.2(a). Phase I Renewable Generator Construction Inputs (000's of 2001 Dollars)

Type of Outlay	IMPLAN Sector No.	2000	2001	2002	2003	2004
Turbine Equipment	285	16,024	7211	3689	13,373	47,810
Road Construction	39	1,204	714	284	977	6,681
Commercial Building Construction	38	5,252	3,529	1,964	4,952	5,877
Interconnection and other costs	41	4,826	2,328	1,269	4,156	13,246
Total	--	27,306	13,783	7,206	23,458	73,614

Columns may not sum to Total due to round off.

Table 3.2(b). Phase II--Renewable Generator Construction Inputs (000's of 2001 Dollars)

Type of Outlay	IMPLAN Sector No.	2005	2006	2007	2008	2009	2010
Turbine Equipment	285	167,608	202,097	112,321	203,150	211,131	197,308
Road Construction	39	16,482	24,956	22,393	23,076	26,321	22,152
Commercial Building Construction	38	24,833	24,676	13,466	31,640	32,280	24,304
Interconnection and other costs	41	48,170	57,371	31,457	59,081	61,354	56,727
Total	--	267,093	309,100	179,637	316,946	331,086	300,491

Columns may not sum to Total due to round off.

The first such pair is the increased O&M expense for the new renewable generators, coupled with the decreased O&M expense for the displaced generation. These values are shown in Tables 3.3 and 3.4. For the new renewable units, we include the full O&M cost expressed in $/MWh of output. In contrast, for the displaced generation, we include only the variable O&M expense, as the fixed O&M expenses will not be avoided unless a unit is decommissioned. Thus, the O&M expense per unit output is significantly greater than that for the avoided expense of the displaced generation.

Table 3.3. Renewable Generator O&M Inputs (2001 Dollars per MWh)

Type of Unit	O&M Cost
Wind	12
Land Fill Gas	15
Hydro (run of river)	20
Fuel cells	3
PV	9
Wood steam	3
MT	12

Table 3.4. Displaced Generator O&M Inputs (Nominal Dollars per MWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Displaced O&M Cost	2.50	2.40	2.30	2.25	2.20	2.24	2.27	2.31	2.35	2.38	2.42

The added O&M costs for new renewables were allocated to IMPLAN sectors as shown in Table 3.5, based on our judgment and the estimated allocations of original construction cost among buildings, roads, and turbine equipment.[10]

Table 3.5. Allocation of Renewable Generator O&M Inputs to IMPLAN Sectors

Sector 43 (Maintenance and Repair of non-residential buildings)	5%
Sector 44 (Maintenance and repair of roads)	15%
Sector 485 (Commercial Machinery Repair)	80%

Avoided O&M costs for displaced generation (not including displaced fuel use) were assigned entirely to Sector 485 (Commercial Machinery Repair) based on our judgment that only generating equipment maintenance would be materially affected by reduced generation at fossil fired units in the short run. In the long run, some units may be retired, leading to greater savings in avoided fixed costs, but omitting them results in a more conservative estimate.

Table 3.6 shows the resulting aggregate inputs to IMPLAN by sector and year to represent changes in O&M expense.[11]

[10] The amounts in this table are the nominal dollar values. They were converted to 2001 dollars internally by the IMPLAN model using deflators specific to the industry sector providing each good or service.

[11] Displaced O&M costs are converted to 2001 dollars internally by IMPLAN using deflators specific to the particular factor inputs allocated as shown in Table 3.5.

The next group of inputs deals with collection and payment of the cost of renewable energy certificates (RECs). The quantity of REC funds collected (and paid out) each year is assumed to be the product of that year's retail sales (including distribution-only sales in restructured states) and the observed REC premium in each state. For purposes of this analysis, we assume that (1) all REC costs are recouped from retail customers, (2) that this does not result in a change in demand for electricity directly, but, rather, in reduced disposable income for goods and services, and (3) that the funds collected are paid in the same year to the entities that earned the RECs by producing eligible power. We therefore reduce the final demand of households, government, and business entities (called Institutions in IMPLAN) by the dollar amount of the REC premium in each year. This reduction of final demand represents the income effect of an increase in electric retail rates. The household portion of REC payments was allocated among nine income levels, and government amount was split between federal, state and local government, all based on the their relative purchases of electricity in 2001. The reductions were proportional to each entity's share of the sales of electricity.

Table 3.6(a). Phase I and Phase II O&M Expense Inputs (000's of 2001 Dollars)[12]

Type of Outlay	IMPLAN Sector No.	2000	2001	2002	2003	2004
Additional Building Maintenance	43	69	100	109	206	320
Additional Road Maintenance	44	207	301	327	618	961
Additional Machinery Maintenance	485	1,104	1,604	1,746	3,296	5,124
Reduced Variable Machinery Maintenance at Fossil Plants	485	-111	-200	-245	-328	-644

[12] The Phase I values for years 2005-2010 are identical to those for year 2004.

Table 3.6(b). Phase II: O&M Expense Inputs (000's of Nominal Dollars)

Type of Outlay	IMPLAN Sector No.	2005	2006	2007	2008	2009	2010
Additional Building Maintenance	43	664	1,003	1,114	1,502	1,876	2,198
Additional Road Maintenance	44	1,991	3,010	3,343	4,506	5,627	6,593
Additional Machinery Maintenance	485	10,617	16,053	17,829	24,032	30,010	35,165
Reduced Variable Machinery Maintenance at Fossil Plants	485	-2,472	-3974	-5,652	-6,893	-8,120	-9,268

We further assumed that the renewables industry is composed 40% of activities matching those in IMPLAN Sector 451 (Management of Companies) and 60% Sector 436 Lessors of Non-financial Intangible Assets.[13] Table 3.7 shows the dollar amounts collected and transferred to the sectors used to represent the incremental portion of the new renewables industry.

In Table 3.7, the small changes in the inputs during the first three years represent mainly variations in the total retail sales of power in Maine. The large jump in 2003 represents the addition of Massachusetts and Connecticut with their much larger loads. In addition, those states set standards for RPS eligibility that were more stringent, leading to a much higher market price for RECs eligible for use in those states.

[13] Our reasoning for selecting these two sectors is that the sale of RECs is essentially the lease of an intangible non-financial asset, namely the right to use the RECs distributed by the NE-ISO GIS, while the business of building and running the generators (aside from the equipment-driven O&M already discussed) is similar to the management of a corporation. We developed the 60/40 split by examining the factor input distribution (the Gross Absorption and Value Added indices) of the two sectors and applying our judgment. The resulting "pseudo-sector" includes small inputs of general goods and services consistent with an office-based business, a modest amount of labor input, and a majority of value added components related to depreciation, dividends, debt service and the like.

Table 3.7(a). Phase I REC Funds Flow Inputs (000's of Nominal Dollars)[14]

Type of Outlay	IMPLAN Sector No.	2000	2001	2002	2003	2004
Final Demand: Institutions	10001-10009, 11001, 12001, 13001	-0.107	-0.142	-0.231	-4,761	-11,752
Final Demand: Management of Corporations	451	0.043	0.057	0.092	1,904	4,701
Final Demand: Lessors of Intang. Non-financial Assets	436	0.064	0.085	0.139	2,857	7,051

Table 3.7(b). Phase I REC Funds Flow Inputs (000's of Nominal Dollars)[15]

Type of Outlay	IMPLAN Sector No.	2005	2006	2007	2008	2009	2010
Final Demand: Institutions	10001-10009, 11001, 12001, 13001	-19,357	-19,776	-20,195	-20,614	-21,034	-21,453
Final Demand: Management of Corporations	451	7,743	7,910	8,078	8,246	8,413	8,581
Final Demand: Lessors of Intang. Non-financial Assets	436	11,614	11,866	12,117	12,369	12,620	12,872

[14] REC costs are converted to 2001 dollars internally by IMPLAN using deflators specific to the particular sectors allocated as shown in Table 3.7.

[15] REC costs are converted to 2001 dollars internally by IMPLAN using deflators specific to the particular sectors allocated as shown in Tables 3.7 and 3.8.

Table 3.8(a). Phase II REC Funds Flow Inputs (000's of Nominal Dollars)

Type of Outlay	IMPLAN Sector No.	2000	2001	2002	2003	2004
Final Demand: Institutions	10001-10009, 11001, 12001, 13001	-0.107	-0.142	-0.231	-4,761	-11,752
Final Demand: Management of Corporations	451	0.043	0.057	0.092	1,904	4,701
Final Demand: Lessors of Intang. Non-financial Assets	436	0.064	0.085	0.139	2,857	7,051

Table 3.8(b). Phase II REC Funds Flow Inputs (000's of Nominal Dollars)[16]

Type of Outlay	IMPLAN Sector No.	2005	2006	2007	2008	2009	2010
Final Demand: Institutions	10001-10009, 11001, 12001, 13001	-50,551	-83,967	-122,519	-152,640	-183,380	-213,148
Final Demand: Management of Corporations	451	20,220	33,587	49,007	61,056	73,352	85,259
Final Demand: Lessors of Intang. Non-financial Assets	436	30,330	50,380	73,511	91,584	110,028	127,889

The last group of adjustments represents the shift of trade in the region from importing fossil fuels (displaced by the new renewable generation) and the corresponding shift in payment of market prices of power (or other negotiated bilateral prices) from the pre-existing wholesale generating entities to those businesses owning the new renewable generation. While the bulk of the wholesale purchase amounts shifted will continue to

[16] REC costs are converted to 2001 dollars internally by IMPLAN using deflators specific to the particular sectors allocated as shown in Tables 3.7 and 3.8.

pay for goods and services similar to those of existing businesses in the power sector, the reduction of money paid for fossil fuels must be re-channeled into a sector more representative of how those funds will be used and not just lost to the economy.

We first developed estimates of the marginal fuel cost per MWh for the region using the marginal fuel mix and the fuel costs discussed above. The amount of renewable generation in each year was multiplied by this unit cost of avoided generation to give the dollars of fossil fuel purchases avoided each year.

The next step was to split those dollars among the affected fuels (at the producer or refiner) and their delivery costs. This resulted in a target dollar amount of reduced demand for the relevant model sectors as shown in Table 3.9. This allocation was made separately for each fuel in the marginal fuel mix.

- Avoided coal purchases (delivered) were split between coal fuel and rail transport based on their 2001 factor inputs in the power sector. In other words, we made the simplifying assumptions that all coal used in the region is delivered by rail.
- Avoided oil purchases were split between oil and gas extraction (well production) output, refinery output, and truck transportation in the same manner. Here, the simplifying assumption was that all oil is delivered by truck.
- Wood fuel purchases--a small part of the avoided fuel purchases--were split in the same way between the logging industry and trucking.
- Natural gas purchases were split between oil and gas extraction and pipeline transport, also using 2001 power sector input factors.

Finally, we represented the total of these reductions as an increase in demand for Sector 436 (Lessors of Intangible Non-financial Assets). That sector was used in this part of the analysis, rather than a split between Sectors 436 and 451 (Management of Corporations), as we did in the REC transfer, to represent the fact that such firms are large users of leveraged capital investments, and that a relatively large portion of their costs therefore occurs in Value Added categories. Sector 436 has a factor input structure consistent with that assumption.[17] This makes the direct employment and induced impacts more conservative than they would be if the transfer were allocated to almost any other sector.

Energy Efficiency Programs

Efficiency program expenditures were allocated among the IMPLAN industrial sectors using the percentages shown in Tables 3.10. Ten percent of each program's expenditures were allocated to Sector 450 (Miscellaneous Technical and Professional Services) to represent program management, marketing, design and evaluation costs. The remainder was allocated to relevant IMPLAN sectors based on our experience and judgment.

[17] Payments to lessors of intangible non-financial assets are converted to 2001 dollars internally by IMPLAN using deflators specific to that particular factor input.

To address the source of the funds spent in the above programs, we reduced final demand in households, government and businesses by the amount of the EE outlays in each year. The residential program outlays shown in the table above were allocated among the household income categories according to their level of purchases from the power sector in 2001. The remaining program outlays were allocated among the federal government, state and local governments, and business entities according to their level of purchases from the power sector in 2001.

Table 3.9(a). Avoided Fossil Fuel Funds Flow Inputs (000's of 2001 Dollars)[18]

Type of Outlay	IMPLAN Sector No.	2000	2001	2002	2003	2004
Logging	14	-1	-16	-24	-31	-46
Wholesale Trade*	390	-1,332	-3,374	-6,071	-11,308	-22,777
Rail Transport	392	-9	-34	-65	-66	-70
Water Transport	393	-45	-108	-164	-224	-364
Trucking	394	-33	-105	-165	-219	-341
Pipeline Transport	396	-204	-531	-1,183	-2,911	-6,592
Lessors of Intangible Non-financial Assets	436	1,624	4,169	7,672	14,759	30,189

** All fossil fuel purchases are assumed to be imports, which are represented in the Wholesale Trade Sector.*

[18] Phase I values for years 2005-2010 are identical to those for 2004.

Table 3.9(b). Phase II: Avoided Fossil Fuel Funds Flow Inputs (000's of 2001 Dollars)

Type of Outlay	IMPLAN Sector No.	2005	2006	2007	2008	2009	2010
Logging	14	-100	-189	-310	-463	-643	-847
Wholesale Trade*	390	-70,140	-145,194	-248,719	-374,321	-515,839	-674,608
Rail Transport	392	-84	-108	-143	-186	-233	-288
Water Transport	393	-902	-1,677	-2,699	-3,908	-5,300	-6,881
Trucking	394	-812	-1,507	-2,433	-3,549	-4,842	-6,312
Pipeline Transport	396	-21,972	-46,765	-81,062	-122,591	-168,799	-220,086
Lessors of Intangible Non-financial Assets	436	94,010	195,449	325,366	505,018	695,656	909,023

** All fossil fuel purchases are assumed to be imports, which are represented in the Wholesale Trade Sector.*

Table 3.10. Allocation of Efficiency Program Outlays (% of Program Total)

Sector/Program	Allocation
Residential	
New Construction	
ME, VT, NH	10% 450, 80% 33, 10% 34
MA, RI, CT	10% 450, 50% 33, 40% 34
New England	weighted average of above by population
In Home Services/Retrofit	20% 450 (half program overhead, half audit-type work) 20% 486 30% 42 5% each to 278, 277, 325, 226, 330, 331
Products and Services	
	Same as In Home but apply retail margin to the product sectors
Commercial and Industrial	
New Construction	20% 450 (half overhead, half extra technology challenge) 40% 37 40% 38
Retrofit/Products and Services	20% 450 (same as above) 20% 485 30% 43 5% each to 276, 277, 278, 325, 326, 334

To represent the reduction in operation and maintenance expenses associated with a reduced level of fossil fuel generation, we reduced final demand in the electric power sector each year by the variable operation and maintenance costs associated with the avoided generation. We further adjusted the use of fossil fuels (and transportation to deliver them) so that the makeup of changes in fuel and transportation inputs used by that sector corresponded to the marginal generation fuel mix for New England. These adjustments were performed in the same manner as for renewable operations impacts, described above.

Finally, we gave to households, government and businesses, in the manner indicated above, their shares of the avoided operation and maintenance costs and the avoided fuel and transportation costs.

Table 3.10a. IMPLAN Sectors Used in Allocation of Efficiency Program Outlays

IMPLAN Sector	Industry
33	New Residential Single Family Construction
34	New Residential Multi-Family Construction
35	Residential additions
37	New Manufacturing buildings
38	New Commercial/Institutional buildings
41	Other new construction
42	Maintenance and repair of residential buildings
43	Maintenance and repair of non-residential buildings
276	C&I fans and blowers manufacturing
277	Heating manufacturing exc. warm air furnaces
278	AC, Refrigeration manufacturing, warm air furnaces
325	Light bulbs manufacturing
326	Lighting fixtures manufacturing
330	Household refrigeration manufacturing
331	Household laundry manufacturing
334	Motor and generator manufacturing
450	Misc. professional and technical services
485	Commercial machinery repair and maintenance
486	Household goods repair and maintenance

3.2 Economic Impact Results

In modeling the eleven year period from 2000 through 2010, our analysis assumes that existing efficiency programs continue to perform at 2003 levels, producing additional investments and new, increased savings each year. In a few instances, planned changes to those efficiency programs were also reflected. For renewable energy, the Phase I analysis assumes the generating plants that came online during 2000 through 2003 continue operating through 2010, but that no new renewable generating plants are added. The Phase II analysis added new renewable generation as explained above.

The economic impacts (and potential emission reductions) presented below represent the projected *net* increases or decreases due to the assumed amount of energy efficiency spending and renewable generation.

IMPLAN economic impact results are divided into three categories: direct, indirect, and induced.

Direct impacts are the outlays for specific goods and service purchased. This includes the construction and O&M costs incurred for the actual renewable generators and the goods and services purchased to operate efficiency programs. For renewable generators, this includes generator equipment itself, access road construction, construction of on-site buildings, and costs of interconnecting with the electric transmission system. For efficiency programs, direct costs include incremental cost of more efficient equipment and building construction, installation labor, and program overhead costs.

These direct purchases are made from specific industries, but those industries, in turn, make further purchases from other segments of the economy. For instance, road construction requires the purchase of crushed stone (from the mining sector), asphalt (from the petroleum products sector), paving machinery and heavy trucks (from the manufacturing sector), and various types of professional, such as surveying and equipment maintenance. Each of those industries also makes further purchases to meet its needs. The fraction of all of those purchases that are made inside the local region are called indirect purchases and needs to be computed and added to the direct impact. All those indirect purchases are included in IMPLAN's indirect impact total.

Lastly, each of the sectors providing the direct and indirect goods and services used employs labor and various fractions of the purchase costs go to labor, profits (and dividends), rents, and taxes. Those outlays for labor and so on also result in further purchases of goods and services by households and government. These are called induced impacts.

For each issue examined in this study, the tables below indicate the direct, indirect and induced economic impacts and the total impact for the years 2000 through 2010, plus the total for the eleven years. Three types of impacts are reported: change in regional output (the sum of all goods and services produced in the New England economy), change in employment, and change in labor income. All dollar amounts are in 2001 dollars, but totals are *not* discounted over time. Employment impacts are in job-years, i.e., one permanent job created in 2000 will result in eleven job-years over the study period.

The direct expenditures we derived are set out in Section 3.1 of this report. IMPLAN reports those amounts as its reported amount of direct impact on output in dollars. The direct impact on employment and labor income are derived using IMPLAN's regional factor input database. The indirect impact on output in dollars is derived by IMPLAN using its I/O matrix for the region, and the indirect impacts on labor and labor income are, again, derived using IMPLAN's regional factor inputs, this time applied to the indirect output change. Induced output changes are the result of spending by households and government using wages, proprietor's income, and taxes. The induced output changes flow from the sum of direct and indirect output changes driven by IMPLAN's database of historical data. Induced employment and labor income changes are computed in the same way as for direct and indirect activity.

Renewable Generator Construction Economic Impact Results

Construction of each renewable generator considered in this study required the expenditure money on the generator itself, civil works (mainly roads), buildings, and electric system interconnection improvements. The estimated amounts for each year are shown in Table 3.2. Those amounts were specified as inputs to IMPLAN and are restated by IMPLAN as its direct impact amount for the economic output. These impacts occur *only* in the year of construction and are not repeated.

It is worth noting that the moderate regional output multiplier seen here ($4,178,719/$1,839,720 = 2.27) is driven in large part by the fraction of the total expenditures on generating equipment that IMPLAN's database indicates would be purchased in New England. This fraction is the regional purchase coefficient or RPC and, in this case, is 69.8%. This is actually the value for turbine-type generator equipment in general and could differ either up or down from the actual, depending on how New England's wind generator industry develops. The employment and labor income multipliers are somewhat larger, 3.21 and 2.75, respectively.

Table 3.11. Renewable Generator Construction Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	27,306	7,479	23,013	57,798
2001	13,783	3,969	12,144	29,896
2002	7,206	2,089	6,416	15,711
2003	23,458	6,509	20,026	49,993
2004	73,614	23,281	70,453	167,348
Phase I Total 2000-2004	145,367	43,327	132,052	320,746
2005	257,093	81,195	246,743	585,031
2006	309,100	97,495	295,857	702,452
2007	179,637	57,313	172,903	409,853
2008	316,946	100,507	305,229	722,681
2009	331,086	105,115	319,001	755,202
2010	300,491	94,633	287,630	682,754
Phase II Total 2000-2010	1,839,720	579,585	1,759,415	4,178,719

Source: IMPLAN runs. Columns and rows may not sum may not to totals due to round off.

Table 3.12. Renewable Generator Construction Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	161.8	63.3	240.9	466.0
2001	90.0	34.3	127.3	251.6
2002	48.2	18.2	67.3	133.6
2003	143.1	55.5	209.7	408.2
2004	410.1	184.9	734.6	1,329.5
Phase I Total 2000-2004	853.2	356.2	1,379.8	2,588.9
2005	1,441.4	649.0	2,572.8	4,663.1
2006	1,719.2	774.6	3,084.5	5,578.3
2007	1,032.0	455.0	1,803.7	3,290.6
2008	1,806.0	804.8	3,183.4	5,794.1
2009	1,892.9	841.1	3,327.3	6,061.3
2010	1,669.3	752.3	2,998.5	5,420.2
Phase II Total 2000-2010	10,414.0	4,633.0	18,350.0	33,396.5

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.13. Renewable Generator Construction Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	8,248	3,037	9,693	20,979
2001	4,525	1,623	5,112	11,260
2002	2,414	857	2,700	5,972
2003	7,263	2,650	8,433	18,347
2004	22,040	9,231	29,744	61,015
Phase I Total 2000-2004	44,490	17,398	55,682	117,573
2005	77,405	32,316	104,163	213,885
2006	92,461	38,689	124,904	256,055
2007	55,034	22,679	72,979	150,692
2008	96,605	40,006	128,836	265,448
2009	101.164	41,815	134,646	277,626
2010	89,822	37,577	121,431	248,830
Phase II Total 2000-2010	556,981	230,480	742,641	1,530,109

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Renewable Generator Operation Economic Impact Results

Estimating the operational impact of the renewable generators considered in this study required us to characterize the impact of RECs on retail consumption, outlays for repair and maintenance associated with both the new and displaced generation, and the shift of dollars from fossil fuel imported into the region to other uses. The estimated amounts and IMPLAN sectors for those input changes are shown for each year in Tables 3.14, 3.15 and 3.16. Those amounts were specified as inputs to IMPLAN and are restated by IMPLAN as its direct impact amount for the economic output as shown in the impact tables below. These impacts occur in each year of operation and are shown here accumulated across all the units operating in a given year, based on their reported output.

The impact on output is positive in most years. The direct impact on employment is negative, and the observed employment and labor income increases, where they exist, are due to shifts in the makeup of factor inputs for the region, rather than an additional stimulus, alone. The major investments in renewable generation in Phase II can be expected to cause significant changes in the demands in the economy. Former demands for goods and services related to fossil fuels and their transportation and for operation and maintenance on fossil fuel plants will decrease. It is to be expected that jobs and job income associated with filling these demands will also decrease. [19]

Two particular issues should be kept in mind in interpreting the economic impacts of renewable generation operation, in addition to the caveats discussed in Section 1.3 of this report:

- The O&M assumptions are conservative. We have included the *complete* cost of renewable O&M while only crediting the economy in the model with the *variable* part of the fossil fuel O&M. With investments of this magnitude in renewable generation, it is possible that some fossil fuel generators will be decommissioned or new units deferred. Were the economy credited with the full O&M cost savings from such decommissioned or deferred generators, the results of the simulation would be more positive.
- Our use of IMPLAN's sectors to represent shifts in factor demands, while a reasonable adaptation given the model's structure, may understate the positive effects of renewable generation operation. This understatement could occur because we use the wholesale trade and bulk transportation sectors to remove demand associated with the decreased demand for fossil fuels and their transportation. Fossil fuel demand is largely supplied from sources outside the New England, so the appropriate way to model its reduction is to use sectors for which a decrease in demand has relatively little direct and indirect (but not necessarily induced) impact on the local economy. Wholesale trade and bulk transportation, although providing a way to decrease demand without having all of that decrease affect the local economy, do have some job and labor income impacts on the local economy, set at the average for all goods sold or shipped at wholesale in the region. The IMPLAN model structure is removing those jobs and

[19] This simulation uses fossil fuel price forecasts from the New York Mercantile Exchange (NYMEX) and the Energy Information Administration. These forecasts show nominal fossil fuel prices declining from 2005-2010. During such a period of declining fossil fuel prices, a simulation of the economic impact of renewable generation will not produce as positive results as would such a forecast in times of price increases in fossil fuels. Use of a forecast for prices of fossil fuels that reflected price increases over time show a more positive impact of renewable generation.

income even though it is not certain that the changes associated with reduced demands for imported fossil fuel and fuel transportation will have such extensive impacts on the local economy.[20]

It is also useful to remember that the renewable generation operation can only exist as renewable generator construction occurs. When we combine the renewable construction impacts with the renewable operation impacts to compute the total renewable impacts, the impacts on output, employment and labor income are all positive. Since there is no reason to believe that renewable generator construction will stop at the end of the study period, one can anticipate continued positive effects.

In the simulation, imports of fossil fuel are first converted into value added within the region. Second, retail purchases are reduced (due to REC collections), but a corresponding amount is placed into the economy in a high-Value Added sector. For these reasons, the *multipliers* (but not the actual impact estimates) shown in this data may not be subject to the same type of interpretation found in economic impact studies of new demand or new output and should be used cautiously.

Phase I: Renewable Generator Operation Economic Impact Results

In Phase I of this study we considered the impact of renewable generators which came on line in 2000-2004. Their construction impacts in 2000-2004 were shown in the previous section. Those generators built in 2000-2004 have continuing impacts in operating costs through the end of the study period. The operating impacts shown for each of the years 2005 through 2010 are identical to those obtained in 2004 and are shown as one combined total for those years.

[20] It is interesting to note, for example, that in 2010, the last year of the forecast, wholesale trade and pipeline transportation together lost 4,520.1 job years and $360,958,770 in labor income. These two sectors, whose job and income losses are overestimated by our simulation, represent 63% of the reported job year losses and 86% of the labor income losses in 2010.

Table 3.14. Renewable Generator Operation Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	1,269	-28	1,107	2,349
2001	1,805	-558	1,211	2,459
2002	1,938	-1,491	694	1,141
2003	5,828	-2,873	4,720	7,675
2004	10,668	-6,544	8,653	12,776
Sub-Total	21,508	-11,494	16,385	26,400
2005-2010	81,972	-39,426	80,340	122,886
Total	103,480	-50,920	96,725	149,286

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.15. Renewable Generator Operation Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	3.5	-0.7	10.3	13.1
2001	-4.5	-5.7	9.3	-0.9
2002	-20.3	-14.4	1.1	-33.6
2003	-41.7	-28.5	37.1	-33.1
2004	-103.4	-64.3	65.4	-102.3
Sub-Total	-166.4	-113.6	123.2	-156.8
2005-2010	-673.2	-390.6	684.0	-379.8
Total	-839.6	-504.2	807.2	-536.6

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.16. Renewable Generator Operation Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	-89	-32	447	326
2001	-804	-265	459	-610
2002	-2,043	-669	203	-2,509
2003	-3,415	-1,303	1,865	-2,853
2004	-7,629	-2,933	3,416	-7,146
Sub-Total	-13,980	-5,202	6,390	-12,792
2005-2010	-41,130	-17,652	32,772	-26,010
Total	-55,110	-22,854	39,162	-38,802

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Phase II: Renewable Generator Operation Economic Impact Results

In Phase I of this study we considered the impact of renewable generators which came on line in 2000-2004. In Phase II we include the renewable generators which we think will come on line in 2005-2010. As was the case in Phase I, each generator placed into service has continuing operation impacts throughout the study period. The following tables show the operating impacts of these generators in 2000-2010.

Table 3.17. Renewable Generator Operation Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	1,269	-28	1,107	2,349
2001	1,805	-558	1,211	2,459
2002	1,938	-1,491	694	1,141
2003	5,828	-2,873	4,720	7,675
2004	10,668	-6,544	8,653	12,776
Sub Total	21,508	-11,494	16,385	26,400
2005	31,435	-22,761	27,503	36,175
2006	49,637	-49,373	35,308	35,572
2007	64,581	-88,288	33,001	9,294
2008	81,719	-133,478	25,976	-25,783
2009	98,454	-184,572	14,434	-71,684
2010	113,538	-242,273	-3,630	-132,365
Total	460,872	-732,239	148,977	-122,391

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.18. Renewable Generator Operation Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	3.5	-0.7	10.3	13.1
2001	-4.5	-5.7	9.3	-0.9
2002	-20.3	-14.4	1.1	-33.6
2003	-41.7	-28.5	37.1	-33.1
2004	-103.4	-64.3	65.4	-102.3
Sub Total	-166.4	-113.6	123.2	-156.8
2005	-397.8	-221.5	208.1	-411.2
2006	-854.7	-475.8	207.0	-1,123.5
2007	-1,537.0	-844.0	69.7	-2,311.3
2008	-2,290.7	-1,272.7	-138.8	-3,702.2
2009	-3,144.7	-1,756.4	-411.1	-5,312.3
2010	-4,111.8	-2,301.5	-769.3	-7,182.7
Total	-12,503.1	-6,985.5	-711.2	-20,200.0

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.19. Renewable Generator Operation Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	-89	-32	447	326
2001	-804	-265	459	-610
2002	-2,043	-669	203	-2,509
2003	-3,415	-1,303	1,865	-2,853
2004	-7,629	-2,933	3,416	-7,146
Sub Total	-13,980	-5,202	6,390	-12,792
2005	-25,304	-10,067	10,983	-24,388
2006	-57,659	-21,735	13,479	-65,915
2007	-105,887	-38,670	11,350	-133,208
2008	-163,827	-58,449	6,878	-215,398
2009	-229,726	-80,785	276	-310,235
2010	-304,651	-105,971	-9,332	-419,953
Total	-901,034	-320,879	40,024	-1,181,889

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Renewable Generator Total Economic Impact Results

The following tables combine the estimated construction and operational impacts for the renewable generators considered in this study.

Phase I:

Table 3.20. Renewable Generator Total Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	28,575	7,451	24,120	60,147
2001	15,588	3,411	13,355	32,355
2002	9,144	598	7,110	16,852
2003	29,286	3,636	24,746	57,668
2004	84,282	16,737	79,106	180,124
Sub-Total	166,875	31,833	148,437	347,146
2005-2010	81,972	-39,426	80,340	122,886
Total	248,847	-7,593	228,777	470,032

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.21. Renewable Generator Total Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	165.3	62.6	251.2	479.1
2001	85.5	28.6	136.6	250.7
2002	27.9	3.8	68.4	100.0
2003	101.4	27.0	246.8	375.1
2004	306.7	120.6	800.0	1,227.2
Sub-Total	686.8	242.6	1,503.0	2,432.1
2005-2010	-673.2	-390.6	684.0	-379.8
Total	13.6	-148.0	2,187.0	2,052.3

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.22. Renewable Generator Total Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	8,159	3,005	10,140	21,305
2001	3,721	1,358	5,571	10,650
2002	371	188	2,903	3,463
2003	3,848	1,347	10,298	15,494
2004	14,411	6,298	33,160	53,869
Sub-Total	30,510	12,196	62,072	104,781
2005-2010	-41,130	-17,652	32,772	-26,010
Total	-10,620	-5,456	94,844	78,771

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Phase II:

Table 3.23. Renewable Generator Total Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	28,575	7,451	24,120	60,147
2001	15,588	3,411	13,355	32,355
2002	9,144	598	7,110	16,852
2003	29,286	3,636	24,746	57,668
2004	84,282	16,737	79,106	180,124
Sub Total	166,875	31,833	148,437	347,146
2005	288,528	58,434	274,246	621,206
2006	358,737	48,122	331,165	738,024
2007	244,218	-30,975	205,904	419,147
2008	398,665	-32,971	331,205	696,898
2009	429,540	-79,457	333,435	683,518
2010	414,029	-147,640	284,000	550,389
2005-2010	2,133,717	-184,487	1,759,955	3,709,182
Total	2,300,592	-152,654	1,908,392	4,056,328

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.24. Renewable Generator Total Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	165.3	62.6	251.2	479.1
2001	85.5	28.6	136.6	250.7
2002	27.9	3.8	68.4	100.0
2003	101.4	27.0	246.8	375.1
2004	306.7	120.6	800.0	1,227.2
Sub Total	686.8	242.6	1,503.0	2,432.1
2005	1,043.6	427.5	2,780.9	4,251.9
2006	864.5	298.8	3,291.5	4,454.8
2007	-505.0	-389.0	1,873.4	979.3
2008	-484.7	-467.9	3,044.6	2,091.9
2009	-1,251.8	-915.3	2,916.2	749.0
2010	-2,442.5	-1,549.2	2,229.2	-1,762.5
2005-2010	-2,775.9	-2,595.1	16,135.8	10,764.4
Total	-2,089.1	-2,352.5	17,638.8	13,196.5

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.25. Renewable Generator Total Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	8,159	3,005	10,140	21,305
2001	3,721	1,358	5,571	10,650
2002	371	188	2,903	3,463
2003	3,848	1,347	10,298	15,494
2004	14,411	6,298	33,160	53,869
Sub Total	30,510	12,196	62,072	104,781
2005	52,101	22,249	115,146	189,497
2006	34,802	16,954	138,383	190,140
2007	-50,853	-15,991	84,329	17,484
2008	-67,222	-18,443	135,714	50,050
2009	-128,562	-38,970	134,922	-32,609
2010	-214,829	-68,394	112,099	-171,123
2005-2010	-374,563	-102,595	720,593	243,439
Total	-344,053	-90,399	782,665	348,220

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Energy Efficiency Program Economic Impact Results

To estimate the economic impact of the EE programs considered in this study, we relied on historical data and estimates of program savings and costs. We allocated the costs to various relevant economic sectors and reduced final demand for electricity by the variable operation and maintenance associated with the avoided fossil fuel generation.

We reflected the payment of EE costs by electric consumers as a reduction in their expenditures on other goods and services. We also adjusted demand for fuels and bulk transportation to reflect the shift of dollars from fossil fuel imported into the region to other uses. The avoided operation and maintenance costs and avoided fuel costs were given to households, government, and businesses.

The estimated outlays and savings and the relevant IMPLAN sectors for those input changes are shown in the tables above. Those amounts were specified as inputs to IMPLAN and are restated by IMPLAN as its direct impact amount for the economic output as shown in the impact tables below. These impacts occur in each year of program operation and are shown here accumulated across all programs operating, based on their reported and projected savings.

Table 3.26. Energy Efficiency Program Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	99,775	22,936	55,884	178,595
2001	93,775	22,127	48,641	164,709
2002	87,917	20,624	47,271	155,812
2003	74,690	16,544	34,380	125,614
2004	73,224	21,012	51,026	145,262
Sub-Total	429,547	103,243	237,202	769,993
2005-2010	577,262	173,177	480,349	1,230,788
Total	1,006,809	276,420	717,551	2,000,781

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.27. Energy Efficiency Program Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	384.4	230.1	554.3	1,168.8
2001	311.3	224.4	477.1	1,012.9
2002	311.1	207.1	467.2	985.4
2003	262.7	167.1	330.5	760.3
2004	454.9	208.7	507.9	1,171.6
Sub-Total	1,724.4	1,037.4	2,337.0	5,099.0
2005-2010	3,230.8	1,705.8	4,958.3	9,894.9
Total	4,955.2	2,743.2	7,295.3	14,993.9

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.28. Energy Efficiency Program Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	24,454	9,110	21,805	55,369
2001	21,586	8,753	18,674	49,013
2002	20,796	8,150	18,335	47,281
2003	15,966	6,393	12,851	35,210
2004	22,559	8,227	19,988	50,773
Sub-Total	105,361	40,633	91,653	237,646
2005-2010	188,225	70,163	197,761	456,151
Total	293,586	110,796	289,414	693,797

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Combined Economic Impact Results

The following tables show the sum of the impacts from the three analyses above: renewable generation construction, renewable generation operation, and electric efficiency programs.

The values are simply the sums of the impacts of those three analyses. This is implies that the effects are linear: $2 million spent in a certain way will have twice the impact of $1 million spent that way. As the economy responds to changes in inputs and consumption, the flow through effects are not always linear. For example, when electric demand is reduced, it is not the average plant that is throttled back, but the marginal plant, usually an oil or natural gas generator. (We have explicitly adjusted for that particular non-linearity in this study, as explained above.) But as deeper and deeper reductions are made, coal plants may be run less, and their avoided costs differ from those of oil and gas plants. As another example, if sufficient business develops in a region for, say, manufacturing or maintenance of wind generators, a local industry may develop changing the amount that is imported or the industry may become more efficient through economies of scale, reducing the unit costs. Such effects are possible, especially in the later years of this study where the impacts are largest, but are beyond the scope of this study.

Phase I:

Table 3.29. Combined Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	128,350	30,387	80,004	238,742
2001	109,529	25,538	61,996	197,064
2002	97,061	21,222	54,381	172,664
2003	103,976	20,180	59,126	183,282
2004	157,506	37,749	130,132	325,387
Sub-Total	596,422	135,076	385,639	1,117,139
2005-2010	659,234	133,751	560,689	1,353,674
Total	1,255,656	268,827	946,328	2,470,813

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.30. Combined Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	549.7	292.7	805.5	1,647.9
2001	396.8	253.0	613.7	1,263.6
2002	339.0	210.9	535.6	1,085.4
2003	364.1	194.1	577.3	1,135.4
2004	761.6	329.3	1,307.9	2,398.8
Sub-Total	2,411.2	1,280.0	3,840.0	7,531.1
2005-2010	2,557.6	1,315.2	5,642.3	9,515.1
Total	4,968.8	2,595.2	9,482.3	17,046.2

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.31. Combined Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	32,613	12,115	31,945	76,674
2001	25,307	10,111	24,245	59,663
2002	21,167	8,338	21,238	50,744
2003	19,814	7,740	23,149	50,704
2004	36,970	14,525	53,148	104,642
Sub-Total	135,871	52,829	153,725	342,427
2005-2010	147,095	52,511	230,533	430,141
Total	282,966	105,340	384,258	772,568

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Phase II:

Table 3.32. Combined Impact: Output (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	128,350	30,387	80,004	238,742
2001	109,529	25,538	61,996	197,064
2002	97,061	21,222	54,381	172,664
2003	103,976	20,180	59,126	183,282
2004	157,506	37,749	130,132	325,387
Sub Total	596,422	135,076	385,639	1,117,139
2005	365,474	79,915	325,083	770,469
2006	456,544	77,842	415,344	949,730
2007	343,236	-1,000	290,825	633,061
2008	497,916	-2,911	416,315	911,319
2009	531,650	-48,610	420,830	903,870
2010	516,159	-116,546	371,907	771,521
2005-2010	2,710,979	-11,310	2,240,304	4,939,970
Total	3,307,401	123,766	2,625,943	6,057,109

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.33. Combined Impact: Employment (Job-years)

Year	Direct	Indirect	Induced	Total
2000	549.7	292.7	805.5	1,647.9
2001	396.8	253.0	613.7	1,263.6
2002	339.0	210.9	535.6	1,085.4
2003	364.1	194.1	577.3	1,135.4
2004	761.6	329.3	1,307.9	2,398.8
Sub Total	2,411.2	1,280.0	3,840.0	7,531.1
2005	1,540.6	640.1	3,282.5	5,463.2
2006	1,400.0	591.4	4,164.6	6,156.0
2007	37.8	-94.0	2,754.2	2,697.9
2008	57.5	-172.0	3,927.7	3,813.1
2009	-695.5	-611.7	3,823.3	2,516.0
2010	-1,885.5	-1,243.1	3,141.8	13.1
2005-2010	454.9	-889.3	21,094.1	20,659.3
Total	2,866.1	390.7	24,934.1	28,190.4

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

Table 3.34. Combined Impact: Labor Income (000's of 2001 Dollars)

Year	Direct	Indirect	Induced	Total
2000	32,613	12,115	31,945	76,674
2001	25,307	10,111	24,245	59,663
2002	21,167	8,338	21,238	50,744
2003	19,814	7,740	23,149	50,704
2004	36,970	14,525	53,148	104,642
Sub Total	135,871	52,829	153,725	342,427
2005	74,867	30,555	134,844	240,267
2006	67,350	29,069	173,257	269,678
2007	-18,081	-3,776	119,517	97,659
2008	-34,427	-6,187	170,997	130,385
2009	-94,978	-26,393	171,172	49,803
2010	-181,069	-55,700	148,567	-88,202
2005-2010	-186,338	-32,432	918,354	699,590
Total	-50,467	20,397	1,072,079	1,042,017

Source: IMPLAN runs. Columns and rows may not sum to totals due to round off.

4.0 Air Quality Impact Methods and Results

The potential emission reduction results presented below represent projections of the potential *net* increases or decreases due to the assumed amount of energy efficiency spending and renewable generation.

4.1 Potential Impact of Renewable Generation

Table 4.1 and 4.2 presents potential displaced and reduced NO_X, SO_2, and CO_2 emissions due to the renewable generating units covered in this study. They present the results for Phase I and Phase II, respectively. Potential displaced emissions represent how many emissions from centralized power plants renewable generation units displace. Estimates of potential reduced emissions present net emissions reductions by incorporating increased emissions from certain renewable energy sources, such as biomass, biodiesel, and natural gas fuel cells. In other words, the left side of the table presents the avoided emissions from reduced operation of the traditional generating fleet as a result of the Phase I renewable generation, while the right side of the table shows the net effect of those same avoided emissions, but with the emissions of combustion-type renewables added back in.

Table 4.1 Phase I Analysis: Potential Displaced Emissions and Net Reduction in Emissions due to New Renewable Generation (tons)

Potential Displaced Emissions				Potential Net Emission Reduction			
	NOx	**SO2**	**CO2**	**Year**	**NOx**	**SO2**	**CO2**
2000	39	130	31,281	**2000**	39	130	31,281
2001	69	205	57,919	**2001**	69	205	57,919
2002	63	185	74,739	**2002**	63	185	73,169
2003	57	153	93,000	**2003**	57	153	89,703
2004	120	320	169,543	**2004**	119	320	164,261
2005	187	448	262,203	**2005**	155	442	256,921
2006	212	272	264,608	**2006**	180	266	259,326
2007	172	230	259,530	**2007**	140	224	254,248
2008	164	187	253,498	**2008**	132	181	248,216
2009	177	167	252,635	**2009**	145	162	247,353
2010	183	134	252,562	**2010**	150	128	247,280
Total	1,443	2,432	1,971,518	**Total**	1,248	2,398	1,929,677

Table 4.2 Phase II Analysis: Potential Displaced Emissions and Net Reduction in Emissions due to New Renewable Generation (tons)

Potential Displaced Emissions				Potential Net Emission Reduction			
Year	**NOx**	**SO2**	**CO2**	**Year**	**NOx**	**SO2**	**CO2**
2000	39	130	31,281	**2000**	39	130	31,281
2001	69	205	57,919	**2001**	69	205	57,919
2002	63	185	74,739	**2002**	63	185	73,169
2003	57	153	93,000	**2003**	57	153	89,703
2004	120	320	169,543	**2004**	119	320	164,261
2005	467	1,118	653,807	**2005**	372	1,101	585,110
2006	870	1,115	1,083,215	**2006**	704	1,085	951,128
2007	1,022	1,368	1,541,462	**2007**	683	1,308	1,409,375
2008	1,211	1,381	1,871,554	**2008**	853	1,317	1,654,723
2009	1,567	1,487	2,237,004	**2009**	1,184	1,419	1,935,893
2010	1,878	1,382	2,596,187	**2010**	1,459	1,307	2,210,564
Total	7,362	8,844	10,409,712	**Total**	5,603	8,532	9,163,126

In order to estimate net emission reductions, seasonal load characteristics of different renewable units were first identified. Base-load characteristics were used for biomass, biodiesel, landfill gas, and fuel cell units. For other renewable units, such as photovoltaic, wind, run-of-river hydro units, fuel-specific seasonal load characteristics are used. These data is obtained from the Emission Reduction Workbook that Synapse developed for the Ozone Transport Commission (OTC Workbook).[21] The Workbook is a quantitative tool used to estimate emission reductions from a wide variety of energy policies in the Northeast.[22]

Secondly, annual total generation was allocated among four ozone-related seasons for each fuel type unit according to the renewable units' load characteristics. The four seasons are; (1) Ozone Season Weekday; (2) Ozone Season Night/Weekend; (3) Non-Ozone Season Weekday; and (4) Non-Ozone Night/Weekend. The Ozone Season starts in May and ends in September. The weekday is from 7:00 AM. to 10:59 PM, Monday through Friday.

Thirdly, displaced emissions for each season were estimated through multiplying historical and projected seasonal marginal emission rates (Lbs/MWh) by seasonal renewable generation (MWh) for each fuel type unit. The total of displaced emissions by

[21] Seasonal load characteristics for run-of-river hydro units are not included in OTC Workbook, and thus were developed for this study.

[22] The tool was developed by evaluating system marginal emission rates in the three northeastern power pools with the PROSYM/PROMOD dispatch model. The emission rates developed in this modeling were embedded in a spreadsheet designed to allow the user to evaluate displaced emissions from renewable energy and energy efficiency programs implemented in these regions. See: http://www.synapse-energy.com/publications.htm#repo.

all renewable generation units is shown at Tables 4.1 and 4.2. Seasonal marginal emission rates are shown at Table 4.3. The seasonal marginal emission rates from 2000 to 2003 are historical data obtained from the 2003 NEPOOL Marginal Emission Rate Analysis (MEA) report and the emission rates from 2004 to 2010 are projected rates obtained from Synapse's OTC Workbook. Note that the marginal emission rates of all three pollutants are projected to fall from historical levels during the coming decade, as plant turnover places cleaner plants on the margin for larger percentages of the time. Also note that MEA's emission rates were adjusted according to OTC Workbook's ozone-related time periods.

Table 4.3 Historical and Projected Seasonal Marginal Emission Rates (Lbs./MWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Ozone Season Weekday											
NOx	1.98	1.85	1.33	0.73	0.50	0.70	0.80	0.70	0.70	0.70	0.70
SO2	6.53	5.19	3.49	2.23	0.90	1.30	1.10	1.00	0.80	0.60	0.40
CO2	1,540	1,424	1,382	1,175	920	980	1,030	1,010	980	980	980
Ozone Season Night/Weekend											
NOx	1.80	1.50	0.80	0.29	0.80	0.60	0.60	0.50	0.50	0.60	0.70
SO2	6.00	4.40	2.00	0.59	2.40	1.60	0.90	0.80	0.50	0.50	0.50
CO2	1,505	1,340	1,171	974	1,090	1,010	1,000	970	920	920	960
Non-Ozone Season Weekday											
NOx	1.80	1.69	1.44	0.89	0.40	0.40	0.90	0.60	0.60	0.70	0.70
SO2	6.25	5.09	4.66	2.28	0.80	0.70	0.50	0.40	0.40	0.50	0.40
CO2	1,460	1,404	1,506	1,256	920	890	950	940	940	950	950
Non-Ozone Season Night/Weekend											
NOx	1.80	1.60	1.00	0.86	1.10	1.10	0.90	0.80	0.70	0.70	0.70
SO2	5.90	5.00	3.00	2.39	3.30	3.00	1.60	1.30	1.10	0.90	0.70
CO2	1,440	1,393	1,300	1,236	1,130	1,120	1,070	1,050	1,030	1,010	980

Data source: ISO New England Inc., December, 2004 NEPOOL Marginal Emission Rate Analysis; OTC Workbook Version 2.1

Finally, total emissions from certain renewable units, such as biomass, biodiesel, and fuel cell were estimated and applied to the total displaced emissions for estimating net emission reductions. Table 4.4 presents emission rates from those renewable generation units. The results of net emission reductions each year are shown at Tables 4.1 and 4.2, as explained above.

Table 4.4 Emissions from Generation Units

	NOx (Lbs./MWh)	SO2 (Lbs/MWh)	CO2 (Lbs./MWh)
Fuel Cell (Natural Gas)	0.03	0.006	1135
Biodiesel Micro-turbine	1.2		330
Biomass	0.36	0.06	--

Data Source: GRI and NREL 2003; Meidensha 2003; Barrett Consulting Associates, Inc. 2004; Massachusetts Division of Energy Resources (DOER), "Renewable Portfolio Standard Advisory Rulings"

Renewable generation projects selected for our Phase I analysis are projected to displace approximately 1,440 tons of NOx, 2,430 tons of SO2, and 1,970,000 tons of CO2 during the period between 2000 and 2010. Net emission reductions, after accounting for the emissions from certain of the renewable units, are projected to be approximately 1,250 tons of NOx, 2,400 tons of SO2, and 1,930,000 tons of CO2. Net SO2, NOx, and CO2 emission reductions were smaller than the traditional generation emissions avoided by 13%, 1%, and 2%, respectively. The difference between displaced and reduced emissions is most significant for NOx, because of one large biomass plant that became on line on December 31, 2004.

Renewable generation projects selected for Phase II analysis are projected to displace significantly larger amounts of emissions than the Phase I plants, which assumed no new RPS plants came on line after 2004. Displaced emissions in our Phase II analysis are approximately 7,360 tons of NOx, 8,840 tons of SO2, and 10,400,000 tons of CO2 during the period between 2000 and 2010. Net emission reductions are approximately 5,600 tons of NOx, 8,500 tons of SO2, and 9,160,000 tons of CO2. Net NOx, SO2, and CO2 emission reductions were smaller than the traditional generation emissions avoided by 24%, 4% and 12%, respectively. The difference between displaced and reduced emissions is most significant for NOx because a large number of biomass plants were included in Phase II analysis, while the difference in CO2 emission savings was due mainly to inclusion of a number of natural gas fuel cell units. Overall, net emission reductions in Phase II are approximately 4 to 5 times larger than the reductions achieved in Phase I.

Finally note that we refer to these emission reductions as "potential reductions," because many of the oil- and gas-fired steam units that would operate less with new renewable generation currently receive NO_x allowances, and some of them receive SO_2 allowances as well. The extra allowances created by this reduced generation could be traded to other sources, resulting in no reduction in overall system emissions. In fact, if allowance markets are working efficiently, one would expect the industry to emit pollution equal to the capped levels. In this scenario, the new renewable generation would have the effect of lowering the cost of meeting the emission caps. Alternatively, regulators could establish mechanisms to capture and preserve the emission reductions offered by new renewables, such as by lowering emission caps as new, zero-emission generators were added to the system.

4.2 Potential Impact of Electric Efficiency Programs

Table 4.5 presents the potential NO_X, SO_2, and CO_2 emission reductions from year 2000 through 2010 due to energy efficiency programs covered in this study. Unlike renewable generation, displaced emissions equal to reduced emissions in energy efficiency programs. Aside from this difference, displaced emissions were estimated in a manner similar to that used for renewable units: first by allocating cumulative annual savings among ozone-related four seasons based on the typical load characteristics of the aggregated utility DSM programs and then by multiplying historical and projected seasonal marginal emission rates (Lbs/MWh) by seasonal savings (MWh). The quantity of energy savings is given in Table 2.14, and the marginal emission rates in Table 4.3.

In comparison to the impacts of renewable generating units, energy efficiency programs offer significantly larger potential reductions for two reasons: (1) efficiency programs avoid significantly larger quantity of power generation than renewable generation units; and (2) efficiency programs do not emit pollution unlike some types of renewable generation units.

In total, the efficiency programs in our analysis are estimated to reduce significantly larger amount of emissions than renewable energy projects. Reductions achieved during the period between 2000 and 2010 are approximately 16,400 tons of NOx, 25,700 tons of SO2, and 22,520,000 tons of CO2. These figures are around 11 to 13 times greater (depending on which pollutant is considered) than the emission reductions of renewable generating projects under the Phase I analysis and 2 to 3 times those under the Phase II analysis.

Table 4.5 Potential Emission Reductions from Energy Efficiency Programs (Tons)

Year	NOx	SO2	CO2
2000	308	1,036	247,777
2001	907	2,689	753,694
2002	1,109	3,267	1,259,509
2003	924	2,508	1,473,060
2004	1,015	2,572	1,565,527
2005	1,301	2,951	1,926,805
2006	1,949	2,270	2,371,640
2007	1,797	2,247	2,712,014
2008	1,980	2,112	3,030,051
2009	2,408	2,162	3,401,962
2010	2,737	1,885	3,777,552
Total	16,436	25,699	22,519,591

Data source: Synapse calculations using for 200-2003 ISO New England Inc., December 2004, 2002 NEPOOL Marginal Emission Rate Analysis, page 9; and for 2004 through 2010: Synapse OTC Workbook Version 2.1, as well as the sources discussed in Section 2.2 of this report.

4.3 Potential Impact of Combined Renewable Generation and Electric Efficiency Programs

Table 4.6 presents the potential NOx, SO2, and CO2 emissions reduction that combines impact of renewable generation and energy efficiency programs. The Phase I analysis in Table 4.6 indicates the potential emissions reduction by renewable generation under Phase I analysis and by all energy efficiency programs, as discussed above. This resulted in reducing approximately 17,700 tons of NOx, 28,000 tons of SO2, and 24,450,000 tons of CO2 during the period from 2000 through 2010. The Phase II analysis in Table 4.6 presents the potential emissions reduction by renewable generation under Phase II analysis and by the energy efficiency programs as we discussed above. This resulted in reducing approximately 22,000 tons of NOx, 34,000 tons of SO2, and 31,680,000 tons of CO2 during the period from 2000 through 2010. Overall, renewable generation under Phase II analysis and the energy efficiency programs combined reduces 25% more NOx potential emission reduction, 22% more SO2 potential emission reduction, and 30% more CO2 potential emission reduction than renewable generation under Phase I analysis and the energy efficiency programs combined. Note these additional emission reductions are contributed by renewable generation that came or will come on line after December 31, 2004.

Table 4.6 Potential Net Reduction in Emissions from New Renewable Generation and Energy Efficiency Programs (Tons)

Phase I Analysis				Phase II Analysis			
Year	**NOx**	**SO2**	**CO2**	**Year**	**NOx**	**SO2**	**CO2**
2000	347	1,166	279,058	**2000**	347	1,166	279,058
2001	976	2,895	811,614	**2001**	976	2,895	811,614
2002	1,172	3,452	1,332,678	**2002**	1,172	3,452	1,332,678
2003	981	2,661	1,562,763	**2003**	981	2,661	1,562,763
2004	1,134	2,892	1,729,788	**2004**	1,134	2,892	1,729,788
2005	1,456	3,394	2,183,726	**2005**	1,674	4,052	2,511,915
2006	2,129	2,536	2,630,966	**2006**	2,653	3,355	3,322,768
2007	1,936	2,472	2,966,262	**2007**	2,479	3,555	4,121,389
2008	2,112	2,293	3,278,267	**2008**	2,834	3,429	4,684,774
2009	2,553	2,324	3,649,315	**2009**	3,592	3,581	5,337,856
2010	2,888	2,013	4,024,832	**2010**	4,196	3,192	5,988,116
Total	17,684	28,097	24,449,269	**Total**	22,038	34,231	31,682,718