The New Hampshire Climate Change Policy Task Force

New Hampshire Climate Action Plan

A Plan for New Hampshire's Energy, Environmental and Economic Development Future

Appendix 7.2:

Electricity Generation and Use

Carbon Emissions and Economic Modeling: Approach and Assumptions

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Introduction

This document details the approach taken and the assumptions made in order to provide emissions and economic analyses of potential Actions proposed by the Working Groups and the Task Force. The results of the analyses are presented separately in the Analysis Results table. Detailed descriptions of the potential Actions are presented in the Action Reports produced by the Working Groups.

Total State Emissions Business-as-Usual Model:

The business-as-usual New Hampshire fossil fuel greenhouse gas emissions by sector were projected out to 2050 by extrapolating historical emissions data. Linear extrapolations of 1990-2005 emissions data[1] were used to project emissions in the Transportation, Residential, Commercial, and Industrial sectors. Emissions in the Electricity Generation sector were calculated differently because the historical New Hampshire emissions record is punctuated by large fluctuations due to the expansion and retirement of major generation plants. Linear extrapolation of total New England generation was extrapolated, and future New Hampshire generation was projected based on the assumption that New Hampshire will continue to contribute 17.3% of New England generation. Projected emissions were calculated based on the assumption that all future expansion of New Hampshire generation capacity is provided by natural gas plants.

Carbon Emissions Model:

Electricity Generation Model

The electricity generation model uses NH electricity fuel consumption data[2] and net generation data for New Hampshire[3] to characterize existing generation. The average amount of fuel required per MWh of net generation for each fuel type is calculated as the average of historical ratios. For the future projections we use a Business-as-usual (BAU) case and for most solutions, the existing NH generation base is unchanged. Table 1 shows some calculations and parameters of the electricity generation model.

Growth in NH generation is modeled as a linear projection of New England generation. New Hampshire is assumed to retain its 17.3% share of New England generation. This results in a 314,341 MWh/year linear growth in NH generation out to 2050. For the BAU case, all of this growth in generation is met by natural gas power plants.

[1] EPA report: "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006"
[2] Energy Information Administration (EIA) data.
[3] Energy Information Administration (EIA) data.

Table 1: Calculations of parameters related to fuel use for NH electricity generation[4]

Consumption per MWh	
Coal (short tons / MWh)	0.41
Natural Gas (thousand cubic feet / MWh)	7.28
Petroleum [resid + dist] (barrels / MWh)	1.71
Emissions Factors	
Coal Emissions Factor (average) (lbs CO2/million BTU)	215.000
Natural gas Emissions Factor (lbs CO2/1000cuft)	120.593
Petroleum Fuel Oil Emissions Factor (lbsCO2/barrel)	940.109
Emissions Factors per MWh	
Coal Emissions Factor (lbs CO2/MWh)	2283.8
Natural gas Emissions Factor (lbs CO2/MWh)	878.1
Petroleum Fuel Oil Emissions Factor (lbs CO2/MWh)	1604.1

Electricity Consumption Model

Emissions reductions associated with reductions in NH electricity consumption are calculated using the ISO-NE marginal emissions factor. An exponential regression of historical ISO-NE marginal emissions factor data was used to project future values, although the marginal emissions factor was held constant post-2011 when a floor value of 899 lbsCO_2e/MWh is reached by 2011. This is because this emissions factor is approximately that of natural gas generation.

In order to quantify the greenhouse gas reduction and "credit" the state for reduced electricity demand in New Hampshire, we subtract the credit (based on the ISO-NE marginal emissions factor) from total NH electricity generation (determined based on the actual fuel burned in NH generating stations).

Table 2: Historical and projected values of the New England marginal emissions factor (projected values in *italics*)[5]

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011-2050
NE Marginal emissions factor [lbs CO2/MWh]	1,488	1,394	1,338	1,179	1,102	1,107	*1,063*	*1,028*	*994*	*961*	*930*	*899*

[4] Calculated from EIA data, including the EIA NH State Energy Profile and http://www.eia.doe.gov/oiaf/1605/coefficients.html
[5] Calculated from http://www.iso-ne.com/genrtion_resrcs/reports/emission/2005_mea_report.pdf

Emission Reduction Potential Calculation Assumptions:

EGU Action 1.1 Revenue Decoupling
Supporting mechanism, not individually quantified.

EGU Action 1.2 Energy Efficiency Procurement
Modeled as 5, 10, 15, 20, and 24% reduction[6] in NH electricity consumption below BAU. Assumes that the break point of cost-effective energy efficiency procurement is beyond the modeled percentage drop in consumption.

EGU Action 1.3 Combined Heat & Power Resource Standard
Modeled as a 9% reduction in NH consumption linearly phased in by 2020.[7]

EGU Action 2.1 Renewable Portfolio Standard (RPS)
Modeled as 23.8% renewable NH sales by 2025. In 2025, this amounts to 3,425,060 MWh of renewable sales in NH, roughly equivalent to 391 MW of sustained capacity. In 2050, this amounts to 4,443,691 MWh of renewable sales in NH, roughly equivalent to 507 MW of sustained capacity.

EGU Action 2.2 Regional Greenhouse Gas Initiative (RGGI)
The RGGI MOU calls for signatory states to stabilize power sector CO2 emissions over the first six years of program implementation (2009-2014) at a level roughly equal to current emissions, before initiating an emissions decline of 2.5% per year for the four years 2015 through 2018. This approach will result in a 2018 annual emissions budget that is 10% smaller than the initial 2009 annual emissions budget. The first three year compliance period would begin January 1, 2009. Followed RGGI language which explicitly covers up to 2018. Assumed that emissions are capped post-2018. Assumed that the goals for RGGI are applied directly to New Hampshire generation.

EGU Action 2.3 New Source Performance Standard (NSPS)
New generation in NH is modeled at emissions factors of 250, 300, 400, 500, 600, 700, and 800 lbs CO_2/MWh.[8]

EGU Action 2.4 Low and Non-CO2 Emitting Supply Side Resources
Supporting mechanism. Not individually quantified.

EGU Action 2.5 Nuclear Power Capacity

Replace nuclear capacity with natural gas in 2030

[6] http://www.neep.org/policy_and_outreach/synapse_sa_report.pdf
[7] Scenario provided by EGU Working Group.
[8] Scenarios from EGU Working group.

After 2029, all existing generation by nuclear is replaced by natural gas generation.

<u>Replace petroleum, coal and a portion of natural gas base generation with new 1000MW nuclear</u>
1000MW = 8,760,000 MWh/year. This generation replaces all petroleum and coal, and over half of natural gas. Replacement occurs in 2025.

<u>Replace petroleum, coal and a portion of natural gas base generation with 1000MW of new renewables</u>
1000MW = 8,760,000 MWh/year. This generation replaces all petroleum and coal, and over half of natural gas. Replacement occurs between 2012 and 2025.

<u>Replace coal base generation with an equivalent amount of new renewable generation</u>
4,076,075 MWh/year of coal generation replaced with renewables between 2012 and 2025. This is equivalent to ~465 MW of renewable capacity.

<u>Replace coal base generation with an equivalent amount of new NG generation</u>
4,076,075 MWh/year of coal generation replaced with natural gas between 2012 and 2025. This is equivalent to ~465 MW of natural gas capacity.

<u>2.6 Import low carbon power from Canada – mainly Quebec Hydro</u>
Modeled as importation of 1200 MW of hydroelectric power at 80% utilization (8,409,600 MWh annual generation). This generation is modeled as replacing coal, oil, and some natural gas generation.

<u>2.7 Utility Investments in New Renewable Generation</u>
Modeled as capacity development of 50 MW by 2012, 200 MW by 2025 and 400 MW by 2050. Capacity between these years is linearly interpolated. A 80% utilization factor is used resulting in expanded annual renewable generation of 350,400 MWh by 2050, 1,401,600 MWh by 2025, and 2,803,200 MWh by 2050. New generation is modeled as offsetting projected expansion of natural gas generation.

Economic Model:

The CSNE economic modeling team took an "efficient analysis" approach to estimating the economic impacts of different actions proposed by the working groups, given the many different policy options considered. The modeling assumptions used in estimating economic costs and benefits are provided below.

The objective of the economic analysis was to estimate approximate "levels of magnitude" of the economic impacts of each proposed action item. Given the short time frame of analysis and large number of action items under consideration, this economic analysis is not as detailed as previous UNH economic studies of RPS and RGGI. It is instead meant to provide economic context to assist in the decision making process for the task force.

The analysis provided for the task force is limited to direct New Hampshire costs/benefits and does not include assessment of society wide impacts. As much as possible, direct employment impacts are estimated along with costs and benefits. The analysis does not consider potential benefits associated with actions such as reduced health costs due to reduced air pollution emissions and also does not include avoided costs in calculating economic impacts.

However where appropriate, an economic multiplier was used to estimate the broader state-wide economic impacts of cost savings, such as for reduced fuel consumption. An economic multiplier is used to estimate economy-wide impacts of specific economic changes. The UNH Economic team—based on its significant knowledge of the NH economy and to be conservative—chose a $1 economic multiplier for each $1 of savings attributed to an action. The assumptions section discusses whether the economic multiplier was applied to any given action. The 1:1 multiplier is considered conservative.[9]

The economic analysis does not discount costs and benefits of climate change policies to reflect timing or uncertainty. This is consistent with the approach used for NH RGGI and RPS analysis and used in the Stern Report. Ken Arrow, Nobel Laureate Economist, reviewed the Stern Report[10] and concluded that discounting for time and uncertainty did not change conclusions.[11]

In the analysis spreadsheet summarizing the carbon and economic impacts of each action item, levels of magnitude and qualitative information are provided, not precise figures for costs and benefits or the exact timing of those costs and benefits. The economic analysis section below provides an overview of the approach and assumptions use to model the economic costs and benefits of each action.

[9] Federal Reserve Bank, 2002.
[10] Stern Review on the economics of climate change. 2006.
http://www.hm-treasury.gov.uk/independent_reviews/stern_review_economics_climate_change/stern_review_report.cfm
[11] "The case for cutting emissions," Ken Arrow, 2007.

Implementation Costs

- Low	0-$2.5 million
- Moderately Low	$2.5 million to $25
- Moderate	$25 million to $125 million
- Moderately high	$125 million to $500 million
- High	$500 million to $1 billion
- Very high	Greater than $1 billion

- Uncertain: Economic implementation costs were not easily determined without significant research beyond the scope of this part of the analysis.
- Study: Means that the action proposed by the working group is a study to further look at issue, this is meant to avoid confusion in comparison of the costs of different actions.

Potential economic benefits

- Low	0-$2.5 million
- Moderately Low	$2.5 million to $25
- Moderate	$25 million to $125 million
- Moderately high	$125 million to $500 million
- High	$500 million to $1 billion
- Very high	Greater than $1 billion

- Uncertain: Economic implementation costs were not easily determined without significant research beyond the scope of this part of the analysis.

Timing of Costs

- Immediate/higher upfront: The majority of economic cost is experienced in the relative short term with the longer term economic cost being less significant
- Constant/even: The economic cost tends to be relatively constant on an annual basis
- Low short-term/Mostly long-term: The majority of economic cost is experienced in the relative long term with the shorter term economic cost being less significant
- Uncertain: Economic implementation costs were not easily determined without significant research beyond the scope of this part of the analysis

Timing of Economic Benefits

- Immediate/higher upfront: The majority of economic benefit is experienced in the relative short term with the longer term economic benefit being less significant
- Constant/even: The economic benefit tends to be relatively constant on an annual basis
- Low short-term/Mostly long-term: The majority of economic benefit is experienced in the relative long term with the shorter term economic benefit being less significant
- Uncertain: Economic benefits were not easily determined without significant research beyond the scope of this part of the analysis

<u>Who Experiences the Significant Portion of the Costs</u>

- Consumer (Evenly Distributed, Concentrated on particular groups)
- Government (State, Local)
- Business (Evenly Distributed, Concentrated on particular groups)

<u>Who Experiences the Significant Portion of the Benefits</u>

- Consumer (Evenly Distributed, Concentrated on particular groups)
- Government (State, Local)
- Business (Evenly Distributed, Small, Medium, Large)

In the above, "Evenly distributed" means that costs and/or benefits are shared relatively equally across the respective group. "Concentrated on particular groups" means that costs and/or benefits are disproportionately borne by, for example, upper or lower income groups.

Economic analysis uses latest (2008) US-DOE EIA (Energy Information Administration) Energy Outlook in constant $2008. The EIA fuel forecast only goes out to 2030, the assumption was made that the 2030 price continues through 2050 in constant dollars. The only exception is the electricity price which was taken from the Independent Service Operator New England (ISO-NE) CELT (Capacity, Energy, Loads, and Transmission) forecast. The report projects prices specifically for NH out to 2017. The 2017 price was assumed to continue through 2050 in constant dollars.

If current prices are indicative the EIA forecasts are low, however the same fuel forecasts are applied consistently across all sectors for fuel savings. Therefore economic benefits based on fuel savings are appropriate as a comparative tool in the decision making process. It is also important to note that all dollars reported in the economic sections including fuel costs are in constant 2008 dollars. This allows for the reporting of costs and benefits in a dollar value in today's values.

CSNE Fuel Forecast ($2008)

	Units	2012	2025	2050
LPG	Gallon	$ 1.87	$1.89	$ 1.97
Residual Oil	Gallon	$ 1.48	$1.44	$ 1.57
Distillate Oil	Gallon	$ 2.59	$2.61	$ 2.78
Natural Gas	Therm	$ 0.87	$0.90	$ 0.99
Electricity- NH Specific	kWh	$ 0.15	$0.15	$ 0.15
Motor Gasoline	Gallon	$ 2.76	$2.71	$ 2.80
Diesel Fuel (distillate fuel oil)	Gallon	$ 2.75	$2.75	$ 2.91

Source: EIA Annual Energy Outlook for 2008

Economic Calculation Assumptions:

EGU Action 1.1 Revenue Decoupling

Review of existing literature did not provide any clear-cut data that could be applied to New Hampshire to determine economic costs or benefits.[12] The primary conclusion of several different sources referenced was that in and of itself, the policy would be expected to have no direct economic costs and benefits. It merely serves to reduce utility barriers to increased implementation of energy efficiency and therefore only indirectly results in economic benefits.

Costs assumed to be $60,000 annually for administration.[13]

EGU Action 1.2 Energy Efficiency Procurement

Energy Efficiency/Demand Response assumed to cost average $0.035 ($2008) per avoided kWh.[14] Projections of kWhs avoided taken from Carbon CSNE analysis. Savings based on avoided retail cost of electricity. Electricity price forecast taken from ISO New England 2008 CELT forecast through 2017 at ~$0.15 per kWh in NH. Beyond 2018 was assumed to be the constant dollar cost forecast for 2017.

[12] Decoupling, NW Energy Coalition, Available online at http://www.nwenergy.org/issues/energy-policy/utilities/docs/decouple.html
Decoupling of utility rates and profits, Illinois Climate Change Advisory Group, Available online at http://www.epa.state.il.us/air/climatechange/documents/subgroups/power-energy/decoupling-of-utility-rates-and-profits.pdf

[13] Assumption by UNH Economic Team

[14] ISO New England Scenario Analysis Companion Report: Constructing a Future that Meets Regional Goals, Synapse Economics, Inc., August 2007, Available online at http://www.neep.org/policy_and_outreach/synapse_sa_report.pdf

An energy-efficient investment had an assumed 14 year lifetime. Energy efficiency lifetime is based on the value used in the New Hampshire's System Benefit Charge funded energy efficiency programs.[15] Also included in economic benefits is a $1 economic multiplier for each $1 saved from reduced fuel consumption.

Calculated Costs and Electricity Savings due to Energy Efficiency

	Cost of Implementation (Annual $2008 Millions)			Economic Benefits (Annual $2008 Millions)		
EE by 2020	**2012**	**2025**	**2050**	**2012**	**2025**	**2050**
5%	$ 53	$ 59	$ 23	$ (127)	$ (446)	$ (567)
10%	$ 105	$ 118	$ 46	$ (254)	$ (892)	$ (1,134)
15%	$ 158	$ 173	$ 55	$ (381)	$ (1,070)	$ (1,361)
20%	$ 211	$ 224	$ 55	$ (508)	$ (1,070)	$ (1,361)
24%	$ 253	$ 265	$ 55	$ (609)	$ (1,070)	$ (1,361)

EGU Action 1.3 Combined Heat & Power Resource Standard

CSNE Carbon Analysis was used to provide the number of kWh required to meet the portfolio standard. The levelized capital cost and annual operations and maintenance cost was assumed to be $0.0618 per kWh.[16] This was assumed to be ongoing through out the period of time analyzed. The savings were based on kWh avoided and therefore not purchased at the retail rate. Thermal load was assumed to drive CHP demand and therefore not expected to result in any thermal savings. Also included in economic benefits is a $1 economic multiplier for each $1 saved from reduced fuel consumption.

Calculated Costs and Electricity Savings due to CHP

Cost of Implementation (Annual $2008 Millions)			Economic Benefits (Annual $2008 Millions)		
2012	**2025**	**2050**	**2012**	**2025**	**2050**
$ 46	$ 161	$ 205	$ (228)	$ (803)	$ (1,020)

EGU Action 2.1 Renewable Portfolio Standard (RPS)

Estimates of cost and benefits of NH RPS were based on modeler's research in this area, a NH RPS study performed in 2007.[17] Cost is the added cost of Renewable Energy Certificates required to be purchased by the utilities that would be passed through to ratepayers. Economic benefits include natural gas savings due to reduced consumption and employment benefits. Current average wage per alternative energy job is ~$57,000 per year and overall average wage is $41,000.[18] For example, alternative energy employment was expected to increase by ~250 in 2012 and ~550 by 2025. This increase in activity is expected to yield similar

[15] Conversation with PSNH Gil Gelineau, 2007

[16] Combined Heat and Power Partnership, US EPA, Available online at http://www.epa.gov/combdhpp/basic/economics.html

[17] Gittell and Magnusson, Economic Impact of a New Hampshire Renewable Portfolio Standard, February 2007, Available online at http://www.des.state.nh.us/ard/climatechange/pdf/UNH_rps_report.pdf

[18] Bureau of Labor Statistics, 2007

job increases in the overall NH economy. The original study only went out to 2025, and renewable energy required by the portfolio for 2050 was taken from CSNE carbon analysis and results from study extrapolated out to that time.

Cost of Implementation (Annual $2008 Millions)			Economic Benefits (Annual $2008 Millions)		
2012	2025	2050	2012	2025	2050
$ 27	$ 24	$ 31	$ (26)	$ (62)	$ (80)

EGU Action 2.2 Regional Greenhouse Gas Initiative (RGGI)

Estimates of cost and benefits of RGGI in NH were based on modeler's research in this area, a NH RGGI study was performed in 2007.[19] Cost is the added cost of carbon dioxide allowance required to be purchased by the generators that would be passed through to ratepayers. Economic benefits include energy efficiency savings due to investment brought on by participation in RGGI. The original study only went out to 2018. Carbon allowance prices were assumed to go to $10 per ton post 2018. kWh savings were determined using the CSNE carbon analysis model. Employment is expected to increase by 900 in 2025 and 1200 in 2050 (linear extrapolation from RGGI study). Average wage assumed to be $41,000 (see Action 2.1 for methodology.)

Cost of Implementation (Annual $2008 Millions)			Economic Benefits (Annual $2008 Millions)		
2012	2025	2050	2012	2025	2050
$ 40	$ 90	$ 122	$ (34)	$ (290)	$ (500)

EGU Action 2.3 New Source Performance Standard (NSPS)

An average $0.029 premium per kWh was assumed for carbon sequestration -Natural Gas (20 yr LCOE.)[20] Carbon Sequestration does not appear to be variable in emissions therefore cost is the same regardless of level set. In the future, technologies with varying levels of capture may be available, but research did not uncover any information related to this. There are not expected to be any significant direct economic benefits related to the increased costs of the sequestration.

Cost of Implementation (Annual $2008 Millions)			Economic Benefits (Annual $2008 Millions)		
2012	2025	2050	2012	2025	2050
$ 36	$ 155	$ 383	$ (0)	$ (0)	$ (0)

EGU Action 2.4 Low and Non-CO2 Emitting Supply Side Resources

[19] Gittell and Magnusson, Economic Impact in New Hampshire of the Regional Greenhouse Gas Initiative (RGGI): An Independent Assessment, January 2008, Available online at http://www.des.state.nh.us/ard/climatechange/docs/1-09-08UNH_RGGI_study.doc

[20] What are the costs and benefits of Carbon Capture and Sequestration?, National Energy Technology Laboratory, Available online at http://www.netl.doe.gov/technologies/carbon_seq/FAQs/benefits.html#

Assumed annual recurring costs of $200,000 for administrative costs to implement.[21] A supporting mechanism for renewable energy development.

EGU Action 2.5 Nuclear Power Capacity

Replace nuclear capacity with natural gas in 2030

Projected decommissioning costs for Seabrook in the neighborhood of $750 million. The capital cost of a new natural gas power plant is estimated at $800/kW to $1,000/kW for natural gas plants and it is also assumed that annual production costs for nuclear = $5,502 million (compared to $6,825 million for natural gas plants).[22] This indicates a high cost if plant were prematurely closed and replaced with a 1000 MW of natural gas. It is not expected to have significant impacts on electricity prices as marginal natural gas plants would still be expected to set regional market prices as is currently the case. A detailed study is required to fully understand the economic impacts of decommissioning of Seabrook.

Replace petroleum, coal and a portion of natural gas base generation with new 1000MW nuclear

The capital costs for new nuclear plant capacity ranging from $3,000/kW to $5,000/kW (compared to $800/kW to $1,000/kW for natural gas plants.)[23] The cost of prematurely closing natural gas plants would be expected to incur significant costs. A detailed study is required to fully understand the economic impacts of this action.

[21] Assumption from EGU working group
[22] Assumption from EGU working group
[23] Assumption from EGU working group