Cumulative Landscape Impacts of Renewable Energy Alternatives for Northern New England

Ann Ingerson

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THE WILDERNESS SOCIETY

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Related Reports

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Foreword

The three northern New England states of Maine, New Hampshire and Vermont face similar energy opportunities and dilemmas. All have committed to significant greenhouse gas reductions and are beginning to reduce their dependence on fossil fuels. All have similar renewable energy resources, including wind, forest biomass, hydropower and solar and geothermal energy. Over the next few decades, meeting commitments to reduce greenhouse gas emissions will require major investments in new energy infrastructure – investments that will influence the basic design of the region's energy system for many decades into the future.

Building out this new system, and possibly relying more on local energy resources rather than imported ones, will have significant landscape impacts. Aside from hydroelectricity, under the jurisdiction of the Federal Energy Regulatory Commission, large-scale land-intensive renewable energy development is relatively new in this region and the traditional permitting process has generally not been designed to evaluate cumulative environmental impacts across the landscape. Better information about the long-term cumulative effects of renewable energy development can help both communities and state-level decision-makers plan responsibly and guide development to the least damaging sites and technologies. Candid information about impacts also reinforces the critical importance of reducing energy demand. We hope to provide some of that information through this report.

Our report describes – through maps and estimates of acres disturbed – landscape impacts from renewable energy build-out scenarios that provide approximately equal shares of the energy used by electricity, heating and transportation sectors by 2050. Decisions about renewable energy development require balancing benefits against costs, and many of the most important benefits and costs are not part of a project's private financial calculus. Hence the report also lists some key environmental costs and benefits for each energy scenario, and summarizes both greenhouse gas benefits and financial costs in final sections.

Effective climate policy calls for not only reducing emissions as rapidly as possible, but also protecting the wild places in our landscape that offer the best hope for natural systems to adapt under increasing climate stresses. Human residents also benefit directly from resilient ecosystems that moderate and filter storm runoff, continue to attract visitors who support local businesses, and offer residents a respite from daily stresses. Our hope is that the information in this report will contribute to energy policies and decisions that meet our region's energy needs while also supporting less visible but no less valuable wildland values.

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Introduction

In order to illustrate cumulative impacts of renewable energy development over time, this paper presents scenarios for meeting the region's projected 2050 energy use using several alternative renewable technologies. For purposes of this exercise, we assume that fossil energy must be replaced with renewable alternatives as rapidly as possible, hence we do not describe the environmental effects of fossil fuel use – which typically exceed the impacts of renewables – but rather focus on the less well-recognized impacts of renewable energy development.

Although adequate climate mitigation will require a mix of energy solutions, in order to compare impacts we set the scale for each scenario at about 25% of demand for a particular energy sector. We chose the 2050 timeframe and 25% scale to correspond with the New England Governors and Eastern Canadian Premiers 2001 Climate Change Action Plan goal to reduce greenhouse gas (GHG) emissions 75-85% by 2050 to avoid dangerous climate threats.[1] These scenarios are not predictions, but are offered as thought experiments that ask the question "what if" we were to depend on each of these sources in turn to a roughly equal degree.

Of the major energy sectors in 2009, electricity was responsible for approximately 18% of greenhouse gas emissions across these three states, transportation 46% and non-electric space heating and industrial processes 36%. Clearly, reducing nonelectric fossil fuel use is critical to minimizing climate impacts. Some of the best options for reducing emissions from heat and transport, however, involve converting to more efficient electric technologies. Hence our scenarios assume that a large portion of transportation and heating energy will come from electricity, which in turn intensifies the burden on renewable electricity sources.

For each scenario, we include a map that provides a general sense of how impacts are distributed across the northern New England landscape. We also provide estimates of acres affected – both directly through land disturbance and indirectly as fragmenting features that reduce core habitat. The *type* of disturbance may be more important than simply acres affected, so boxes under each scenario describe environmental effects that are more difficult to quantify. Since the benefits of each alternative relative to status quo energy sources also differ, we also list some of the key benefits of each alternative.

Landscape impacts are not the sole criterion that influences renewable energy choices. Policy and siting decision-makers must balance any negative impacts against overall public benefits from renewable energy developments. Those benefits include greenhouse gas reductions resulting from substituting renewable sources for fossil fuels. RPS programs and energy siting guidelines often implicitly assume, however, that all renewable sources are equally "carbon neutral". Actual climate benefits vary considerably. To support rigorous assessments of costs versus benefits, we estimate approximate GHG emissions for each scenario and compare them to emissions from current sources.

Finally, we provide general financial cost comparisons for each scenario. Financial costs largely dictate relative rates of adoption for each technology, but environmental externalities should be considered along with financial costs when making public policy choices about energy sources.[2] Although we have not monetized landscape costs and benefits here, an extensive body of work in environmental

economics indicates that the dollar value of ecosystem services approaches or even exceeds the value of goods that are traded in markets.[3] A recent synthesis of global studies indicates that loss of species from a local ecosystem may be even more critical than climate change as a driver of ecosystem degradation.[4] One way to internalize environmental costs at the project level is to require mitigation through changes in design, operations, restoration, or compensation for unavoidable impacts in the form of off-site resource projection. These measures tend to increase project costs overall. Because of the magnitude of external costs, there may be sound public policy reasons to favor energy options that cost more in narrow financial terms but also minimize environmental harm.

Renewable Energy Scenarios

In order to compare various renewable energy options, we define scenarios that provide up to 25% of energy needs for Maine, Vermont and New Hampshire combined in the electricity, transport and heating sectors by 2050. This is the magnitude of development required to achieve aggregate greenhouse gas reductions of 75-80% by 2050. Aside from Canadian hydroelectricity, scenarios are based on energy generated within the three-state region. The ultimate mix of technologies, including other out-of-region energy sources, will depend on the balance of financial, environmental and social benefits and costs and the policies that influence them. Scenarios were constructed as follows.

1. Estimate 2050 Energy Need – Estimate total demand for electricity, transportation and "other" (heat and industrial processes for residential, commercial and industrial users) in the three state region in 2050:
   - Current energy use in trillion Btu is: electricity = 291 (33%)[5]; heat and industrial processes = 318 (35%); transport = 283 (32%).
   - Project 2050 usage, assuming each use category increases through 2050 at the national rates projected by the Energy Information Administration from 2009 to 2035)[6]: electricity growing at 0.86%/year[7] = 117 trillion Btu (requires 344 in primary energy resources); nonelectric transport growing at 0.24%/year[8] = 301 trillion Btu; other uses growing at 0.55%/year[9] = 366 trillion Btu.
   - Adjust for conversion of 25% of heat and 50% of transport to electricity[10], yielding total electricity use = 192 trillion Btu, non-electric transport = 151 trillion Btu, and non-electric other uses = 275 trillion Btu.[11]
   - Convert electricity use to the more familiar gigawatt-hours (GWh) for purposes of developing scenarios = 56,192 GWh[12]. (Note that primary energy resources used to generate electricity are approximately triple this amount, since conversion to electricity is relatively inefficient. If electricity shifts increasingly to solar and wind, conversion efficiency will actually decline but the energy loss is less important given the abundance and emission-free character of the raw resource.)

2. Define Energy Generation Targets – Define targets by renewable energy source for the region. These targets reflect the degree of development needed to meet GHG reduction goals, but may not be fully feasible for a variety of social and environmental reasons. For our scenarios, each renewable energy technology meets up to 25% of regional demand - a level suggested at both state and regional levels for inland wind, which is currently the most rapidly developing renewable source.[13] Technologies with insufficient resource capability to reach that level (i.e. wood and in-region hydroelectricity) have targets set at the highest technically feasible level. These are purely theoretical targets, for purposes of illustrating comparative impacts.
   - Electricity – 56,192 GWh per year is roughly double current use (includes conversion of 50% transport and 25% heat/industrial to electricity). Scenarios for meeting up to 25% of the region's annual average electricity demand with specific technologies are defined as follows:
     - 25% from in-region onshore wind requires capacity of 5,346 MW. This level of development would utilize about 33% of the potential onshore wind resource estimated by AWS Truepower for the U.S. Department of Energy.[14] Since wind is poorly correlated with daily or seasonal peak electricity load, it would take approximately three times this capacity to meet peak loads, but intermittent wind is unlikely to serve as a peaking resource.[15]
     - 25% from in-region offshore wind requires capacity of 4,009 MW.[16] This level of development would amount to 3% of total DOE AWS Truepower offshore wind capacity for Maine and New Hampshire.
     - 21% from in-region wood biomass requires 1,497 MW of capacity (wood resources, including wastes, are insufficient to sustain the 1,725 MW necessary to meet a 25% goal). This is more than triple the current capacity of 429 MW, and would use 103-306% of available supply, depending on the source of supply estimates;
     - 23% from in-region hydro, requires capacity of 3,407 MW[17] (meeting a 25% goal would require 3,704 MW, which is more than the identified small hydro capacity for the region). At prevailing hydroelectricity capacity factors, this is about a 60% increase over current production (7,500 GWh in 2008 output, dropped to 6,635 GWh in 2010);
     - 25% from Canadian hydropower, requires 2,608 MW (assumes 67% capacity factor, consistent with current Vermont Hydro Quebec contract - considerably higher than local hydro due to high reservoir storage capacity). This is nearly 2.5 times the current estimated HQ power use by northern New England, and would require extensive new transmission capacity.
     - 25% from in-region distributed solar requires 11,879 MW of photovoltaic panels. As for wind, solar is an intermittent resource that is not always available at time of peak load, so meeting peak needs would require 1.27 times this capacity (less than the factor of 3 for wind since solar is better correlated with peak load).[18]
   - Heat – Demand in 2050 grows to 366 trillion Btu compared to 318 today (equivalent to about 2.6 billion gallons #2 fuel oil compared to 2.3 billion today). Scenarios for meeting up to 25% of the region's annual average heating demand with specific technologies are defined as follows:
     - 25% from ground-source heat pumps requires 7,157 GWh of electricity which has been included in the electricity scenarios.

- 25% from wood requires 9.0 million additional tons of wood (with about 4 million tons already used for home and institutional heating). This is 90-266% of available wood supply, depending on estimate source, including some pulp diverted to energy use and available wood waste).

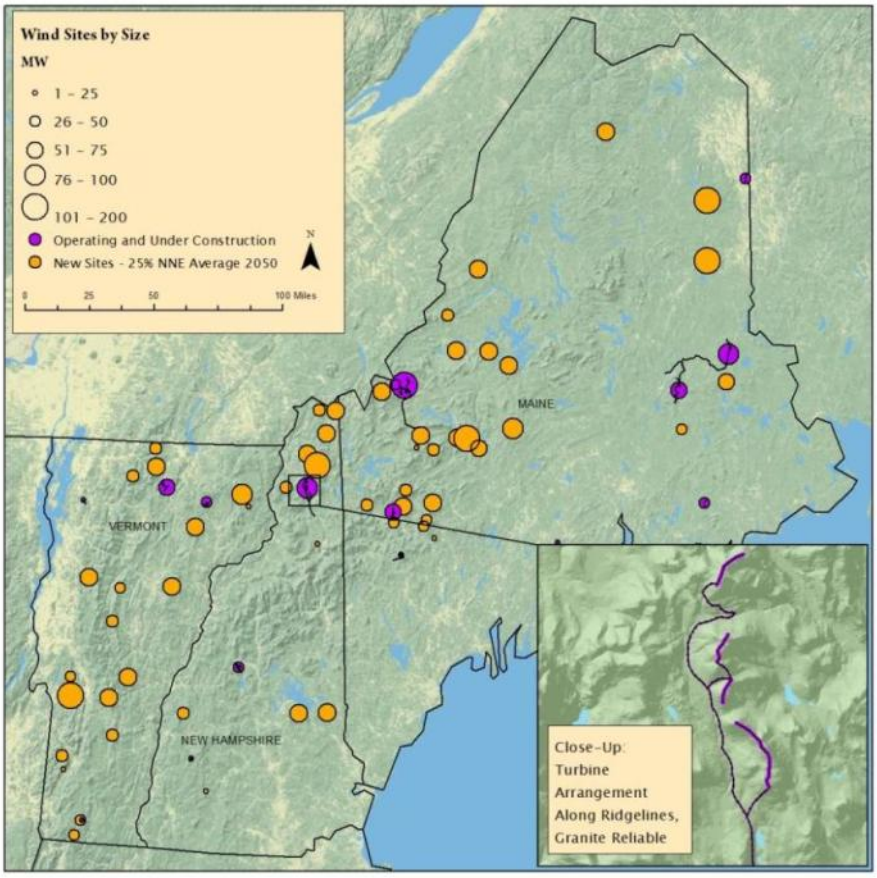
- Transport – Demand in 2050 grows to 301 trillion Btu compared to 283 today (equivalent to about 2.4 billion gallons 80/20 gas/diesel compared to 2.2 billion gallons today). Scenarios for meeting up to 25% of the region's annual average transportation energy demand with specific technologies are defined as follows:
  - 50% from electric vehicles requires 14,698 GWh of electricity which has been included in the electricity scenarios as part of increased electricity demand. As there are few viable options for lowering GHG emissions from transportation, this scenario makes up a larger portion of the sector than the standard 25%. Emissions reductions come not only from the fuel switch but also from reduced total transportation energy due to the improved efficiency of electric motors compared to combustion engines.
  - 13% from wood-based biofuels requires using 10.3 million green tons wood (103-304% of available feedstock, depending on source of supply estimates - wood resources are insufficient to meet a 25% goal.). Maximum feasible feedstock would support production of 334 million gallons of ethanol and biodiesel.
- Reducing energy use through smarter planning, demand-side solutions, and incentivizing better consumer/business choices.
  - 25% reduction (14,048 GWh) in electricity demand through demand-response tools, efficient lighting, appliances, and machinery, plus changes in behavior and consumption choices. Note that our baseline – from U.S. Department of Energy projections – uses fairly pessimistic assumptions about efficiency measures. New England as a region has been a leader in energy efficiency, and ISO-NE projections have recently been revised to reflect the important role of demand-side resources (see Appendix 3).
  - 25% reduction (91.6 trillion Btu) in heating and industrial processing demand through building and equipment efficiency improvements, smaller building size, and behavioral changes.
  - 25% reduction (75.2 trillion Btu) in demand for transportation fuels by reducing vehicle miles traveled through ride-sharing, public transportation, and smart growth settlement patterns, and by improving vehicle efficiency (e.g. fuel economy) and making behavioral changes.

Landscape Impacts of Defined Scenarios

25% Inland Wind Scenario

The map below shows, in purple, 17 wind sites currently operating or under construction (total 351 turbines and 724 MW), and in orange, 25 proposed (total 597 turbines and 1,540 MW) plus 21 theoretical large new sites[19] (total 1,034 turbines and 3,102 MW, assuming 50 3 MW turbines at each site). Together the depicted wind sites would supply 25% of projected average 2050 power needs for the three northern New England states.[20] Sites were selected based on relative capacity factors, and higher-elevation sites tend to have the best wind resources; different selection criteria might reduce estimated impacts due to shorter access roads and transmission lines. Turbine designs adapted to lower wind speeds and located at less remote sites might also reduce overall impact. Analysis by the Appalachian Mountain Club identified 63 Maine sites on mostly private land, with relatively low resource protection conflicts, and mostly within Maine's expedited wind permitting area. The 53 of these sites without existing projects or development restrictions (totaling 1,377 MW of capacity) were clustered similarly to the new theoretical sites shown in Figure 1 below.[21] On the other hand, impacts may be underestimated because additional theoretical sites in our scenario beyond those already operating or proposed are all assumed to be 120MW or larger (smaller projects reduce local impact but would require more sites and hence more overall impact).

Figure 1: Inland Wind Sites to Provide 25% Northern New England Electricity in 2050



Landscape Disturbance

Inland wind resources are concentrated atop ridgelines in this region. Development consists of turbine pads, roads and transmission lines. Turbine pads involve clearing and construction of gravel pads, with smaller concrete turbine foundations. Roads include ridgeline roads (sometimes referred to as "crane paths") between turbines, and access roads with associated cut-and-fill disturbance to link public roads to the wind farm site. Transmission lines connect the facility to the grid and, for wind penetrations contemplated under this scenario, major long-distance transmission upgrades are also required to conduct power from remote wind sites to load centers. Table 1 indicates approximate acres developed for each use. See Appendix I for computation details for all scenarios.

Table 1: Disturbance from 25% Inland Wind Scenario

Disturbance	Direct	Total, including indirect
Ridgelines developed	483 miles	483 miles
Turbine pads	4,955 acres	(see crane paths)
Crane paths	483 miles, 1,990 acres	119,081 acres
Access roads	79 miles, 230 acres	6,512 acres
Connecting transmission	282 miles, 3,885 acres	54,854 acres
Long-distance transmission	2,160 miles, 39,273 acres	211,025 acres
Total area disturbed*	**50,333 acres**	**391,472 acres**

*10% of scenario quantity already in place.

The area of direct impact depends on terrain and configuration of turbines; northern New England wind farms tend to be erected in single strings, which increases direct impact area about 34% above the average for all onshore wind configurations.[22] For perspective, total ridgeline developed under this scenario is approximately the distance from the northeastern tip of Maine to the southwestern corner of Vermont. Rugged ridgetop terrain also increases the total disturbance required to even out dips and curves in access roads and crane paths, and projects located far from load centers increase the required transmission upgrades. Also due to remote locations, affected acres tend to be concentrated in the largest remaining intact blocks of wildlife habitat, which often occur at high elevations due to difficult access. Development along north-south trending ridgelines can further disrupt habitat connections across the landscape that are important to bobcat, lynx, black bear, and other wide-ranging species.

Other impacts from ridgeline wind:

- Physical harm to birds and bats, particularly during migrations when large numbers may follow ridgeline thermals.
- Human and wildlife disruption from roads, lights and noise.
- Widespread visual impact due to location on ridgelines.
- Disruption of watershed function due to road and pad construction and resulting increase in impervious surfaces.
- Foundations use ~400,000 tons concrete.

Benefits of ridgeline wind:

- Rapid construction minimizes duration of most disruptive project phase.
- No air impacts at the site.
- No consumptive water use at the site.

25% Offshore Wind Scenario

Under a 25% offshore wind scenario, turbines would be sited off the Atlantic coasts of Maine and New Hampshire. The map below illustrates one possible configuration for 4,009 MW of offshore wind capacity.[23] We assume use of 5MW floating turbines, as designed by Maine's DeepC Wind Consortium, with 4 200-turbine farms of 1 GW each covering 8.5x8.5 miles - 3 in Maine and 1 in New Hampshire. Locations illustrated on the map are based on interconnection opportunities and areas of interest for offshore wind identified in the Maine Deepwater Offshore Wind Report. (This study looked at capacity for existing transmission to connect projects of 30MW size; 1-GW facilities would require extensive transmission upgrades.)[24]

Figure 2: Offshore Wind Sites to Provide 25% Northern New England Electricity in 2050

Landscape Disturbance

Most of the direct impact from offshore wind farms occurs along the ocean floor – at limited anchor points which nonetheless cover a large area, and from buried cables connecting offshore facilities to the grid. Transmission upgrades on land will also be required if offshore wind farms are as large as projected. However, population centers tend to be located near the coast and some high-capacity connecting points may already exist from retiring nuclear plants (e.g. Maine Yankee), so the total transmission investment would be much lower than for inland wind or imported hydroelectricity.

Table 2: Disturbance from 25% Offshore Wind Scenario

Disturbance	Direct	Total, including indirect
Cable anchors	44 acres	184,960 acres
Collecting transmission within wind farms	200 miles	200 miles
Trunk transmission to shore	80 miles, 194 acres	6,555 acres
Long-distance transmission	715 miles, 13,000 acres	69,853 acres
Total area disturbed*	**13,238 acres**	**261,368 acres**

*None currently operating.

Other impacts from offshore wind:

- Impacts on marine mammals and waterfowl are poorly understood. Direct collisions, noise, vibration, lights, and electromagnetic fields surrounding cables may disrupt normal behavior.
- Impacts to Sea Birds: American Bird Conservancy delineates much of the Gulf of Maine as a "Key Marine Area" where wind may conflict with seabird protection (http://www.abcbirds.org/extra/windmap.html).
- Large rafts of floating turbines may interfere with fisheries or increase the risk of collision for ocean-going vessels.

Benefits of offshore wind:

- Very large and relatively stable wind resource.
- No direct water or air impacts on site.
- Potential for transmission via marine cable reduces land impacts.

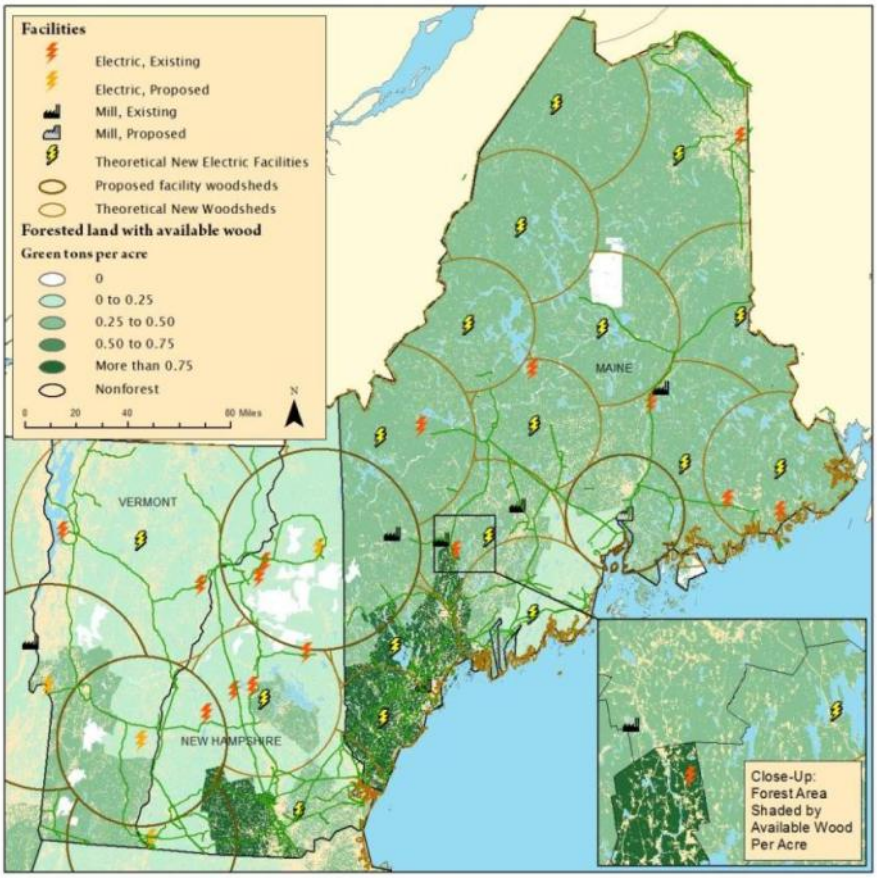
21% Woody Biomass Electricity Scenario

The map below displays locations of 16 existing biomass electricity plants with a combined capacity of 429MW, plus five proposed new facilities totaling 189MW (Berlin, NH 75MW, North Springfield, VT 35MW, Fair Haven, VT 34MW, CPD Winchester, NH 20MW, and Bucksport, ME 25MW) and 18 additional facilities of 25-60MW each, totaling 692MW (see Appendix 2 for details on methods and a list of plant sizes, wood use, and woodshed diameters). Total capacity would be 1,310MW, or up to 1,518MW if all wood waste sources were fully utilized. This is sufficient to meet 21% of average electricity use, which falls short of the standard 25% scenario. Secondary mill, construction/demolition, and municipal wood wastes as a percent of total BTS wood estimates range from 3% (Aroostook) to 33% (Knox) in Maine, 14% (Coos) to 57% (Strafford) in New Hampshire, and 20% (Windham) to 92% (Grand Isle) in Vermont, so if these materials are truly available and could be used responsibly they would substantially expand biomass energy capacity in some counties and could well raise the total potential to the full 25% target. Industry experts, however, often note that mill wastes are essentially already fully utilized.

The map also indicates the approximate area required to supply each facility, assuming exclusive use within the depicted woodshed. In actuality, woodsheds would overlap considerably, though shared use of the resource would lead to similar numbers and sizes of facilities. Wood supply estimates were adopted from the updated Billion Ton Study (BTS) and assume a price of $100/dry ton ($50/green ton) in the year 2030.[25] These are quite optimistic supply estimates, which assume that nearly all timberland is accessible for harvest (only a few reserved areas and slopes >80% are excluded), that all operations use whole-tree harvesting to remove 60-70% of all logging residues, and that widespread changes in forest management across half of harvested land result in thinning to 30% of the maximum theoretical density over 30 years, with all low-grade wood available for fuel.

New biomass electricity sites were located so as to minimize competition with current sites and where sufficient county-level wood supply is available (BTS estimates theoretically already deduct current usage so no woodsheds are shown for existing plants). Actual plants would be unlikely to locate in the more remote locations, and would likely choose locations closer to existing transmission even when that involves shipping wood a greater distance. For all these reasons, this map should not be interpreted as a prediction of where plants will be located, but rather as an indication of the aggregate number needed to supply 21% of 2050 electricity needs.

Figure 3 Wood Biomass Electricity Plants and Woodsheds to Provide 21% Northern New England Electricity in 2050



Landscape Disturbance

The direct footprint of woody biomass electricity generation facilities, including wood storage yards, would be relatively small. These tend to be located near established roadways or rail lines to accommodate heavy traffic from frequent fuel deliveries.

Most impacts from expanded wood energy use would fall on the region's forests. Producing biomass chips at a reasonable cost requires simultaneous removal of higher-value material to help cover harvesting costs. To increase low-grade wood removals by 10.6 million tons, total harvest volume for the three states would need to increase by well over 55%.[26] Biomass electricity development of this magnitude would affect essentially all accessible forest acres in the three states, about 26.5 million

acres, though at a much less intensive level than site development for installing electricity infrastructure of all kinds. If harvesting standards protect long-term forest productivity and encourage carbon accumulation, the impacts will be much less intensive than the clearing and paving associated with energy facility sites, so we classify the forest impact here as indirect.[27]

New access roads would be needed, however, to reach currently unmanaged forest stands, with attendant direct impacts from clearing, soil compaction and erosion. And some new transmission capacity will likely be needed; of the potential plants shown on the map above, five in northern Maine are located at a significant distance from existing high-voltage transmission lines. Transport from the woods to the energy facility would be greater for biomass electricity (average 32 mile radius) than for wood pellets (average 21 mile radius) but would not require transporting to the ultimate combustion site.

Table 3: Disturbance from 21% Woody Biomass Electricity Scenario

Disturbance	Direct	Total, including indirect
Facility footprint	1,950 acres	1,950 acres
Forest area		26,500,000 acres
Forest access roads	2,739 miles, 7,969 acres	225,790 acres (included in above)
Transmission	144 miles, 872 acres	12,323 acres
Total area disturbed*	**19,424acres**	**26,514,273 acres**

*29% of scenario quantity already in place.

Other impacts from woody biomass electricity:

- Degrades local air quality, especially fine particulates.
- Water use by steam boilers, evaporative loss through cooling towers and/or high-temperature water returned to waterways.
- Wood ash hazardous waste disposal if insufficient land base for application as fertilizer.
- Transport of wood fuel with traffic and associated emissions.
- More intensive cutting, need for high volume to finance specialized equipment; expanded forest road network with attendant habitat fragmentation; and reduced late succession forest and associated carbon stocks.39
- Increase in whole tree harvest, with possible damage to residual stands and regeneration, and depletion of nutrients.
- Relatively inefficient energy conversion.

Benefits of woody biomass electricity:

- Increase incentive for timber stand improvement or retaining land in forests.
- May be located near existing transmission capacity, subject to limited trucking distance for fuel.

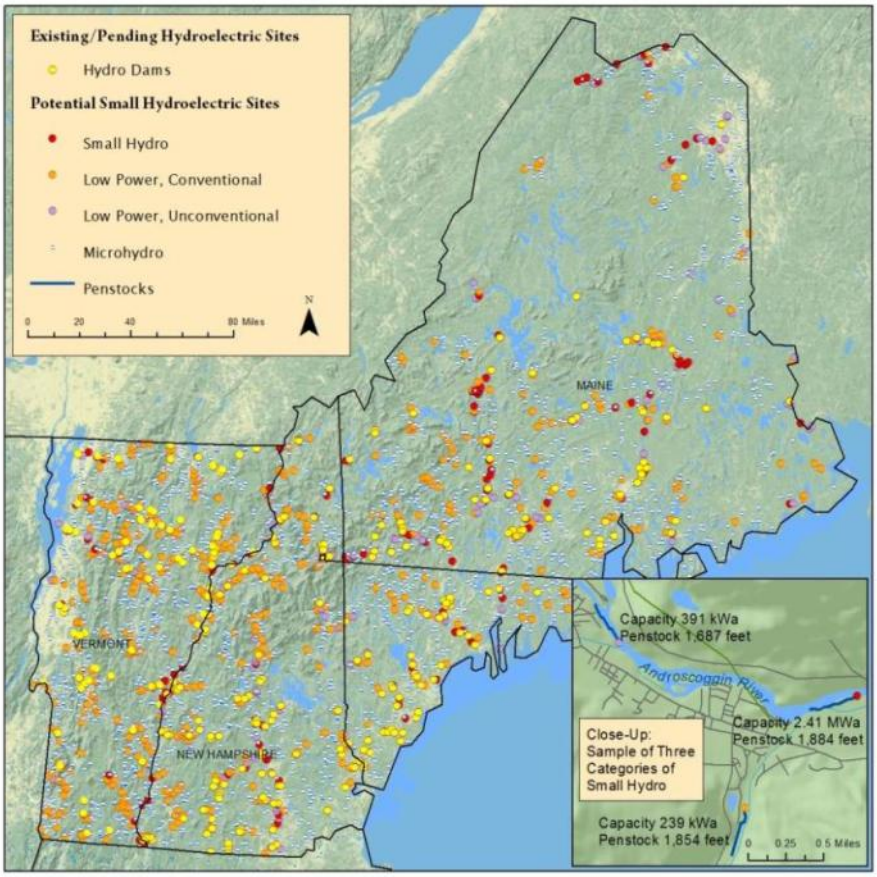
23% Regional Hydroelectricity Scenario

Yellow circles on the map below show approximate locations of existing hydroelectric dams (total 1,535 MW capacity).[28] On November 1, 2012, the Independent System Operator for New England (ISO-NE) listed 193 run-of-river and 22 impoundment dams in these three states with rated generating capacity totaling 1,026 MW (summer) to 1,204 MW (winter).[29] The Federal Energy Regulatory Commission (FERC) has licensed 159 dams with total theoretical capacity of 1,590 MW and issued exemptions to another 87 dams with total capacity 48 MW.[30] These comparisons indicate that not all existing hydroelectric generators export electricity to the grid, and those that do often operate well below their theoretical capacity.

In 2006 the US Department of Energy Idaho National Lab identified 3,364 additional feasible small hydro sites in these three states with installed capacity totaling 1,934 MW (836 MW actual expected generating capacity based on typical capacity factors).[31] The study did not distinguish between sites with or without existing dams (unless already developed for hydroelectricity) so some of the candidate sites likely have old dams present. These new sites plus existing hydroelectric dams could generate 23% of projected 2050 electricity use (12,924 GWh). At the scale of the large map, penstocks are smaller than the hydro site symbols - see the inset for a sense of relative penstock sizes.

Sites were filtered for feasibility using criteria such as lack of restrictive land use designations and proximity to roads, transmission and population centers. Site-specific studies in Vermont using more conservative feasibility assumptions indicate capacity – at existing dams only – may be only 6% to 21% of the Idaho National Lab estimates.

Figure 4: Small Hydroelectricity Sites to Provide 23% of Northern New England Electricity in 2050



Landscape Disturbance

It is difficult to assess the impact of existing hydroelectric dams in these three states because of lack of information about reservoir area or generator design. Some existing dams have substantial reservoirs and most of these have been in place for many decades. For lack of a better approach, we estimate area of impact as the surface area of water bodies labeled "reservoirs" (see Appendix 1 for methods).

For the most part, this landscape impact would persist even if dams were not used to generate electricity, though some dams have been removed over the past several years.

For new hydro facilities, the designs most likely to be permitted are those that collect water via existing low-head dams on small streams or using weirs that do not completely block the channel of larger rivers; unconventional hydro turbines may even be submerged in stream channels. Hence our disturbance estimates assume no new reservoir acreage. Direct landscape disturbance would involve anchoring or burying pipeline along 868 miles of penstock, disturbing an area about 6 feet wide. River reaches with reduced flow would be slightly more than penstock length. Similarly to forest harvest effects for biomass, we consider this an indirect effect since disturbance falls short of land clearing or building.

Feasible sites were pre-selected to be within one mile of roads and existing transmission lines, so new roads and transmission for each individual site would be minimal to service such small facilities. Nonetheless, the sheer number of such projects implies about 328 miles of road building, much of it affecting riparian corridors. Small projects widely distributed across the landscape, that can be scheduled to meet local daily peak loads to some extent, can avoid the need for new long-distance transmission. Transmission connectors could run along the same course as access roads and were modeled at shortest direct-line distance.

Table 4: Disturbance from 23% Regional Hydroelectricity Scenario

Disturbance	Direct	Total, including indirect
Existing reservoirs	10,781 acres	10,781 acres
Power houses	31 acres	31 acres
Penstocks	868 miles, 631 acres	69,650 acres
Access roads and transmission	328 miles, 477 acres	27,433 acres
Stream flow effects		2,630 acres
Total area disturbed*	**11,920 acres**	**110,525 acres**

*69% of scenario quantity already in place.

Other impacts from regional hydroelectricity:

- Damage to aquatic organisms of all kinds has discouraged new hydro development. Impacts include interference with sediment distribution, reduced oxygen levels, changes in temperature, reduced flow during periods of high energy demand, and interference with fish passage.

Benefits of regional hydroelectricity:

- Compared to large impoundments, run-of-river dams have reduced impact, and fish passage would be relatively easy to provide.
- Many existing dams could be retrofit to generate electricity and fish passage as well.
- Air impacts at the site are negligible.
- Small widely dispersed sites can be managed to match local load peaks and alleviate transmission congestion.

25% Canadian Hydroelectricity Scenario

Relying on Canadian hydroelectricity to meet 25% of 2050 projected needs would require purchasing power from dams with 2,525 MW capacity (assumes a relatively high capacity factor of 0.615, relatively high thanks to massive storage). This power cannot be credited toward Renewable Portfolio Standards targets for the New England states, which typically limit the size or type (e.g. run-of-river) of eligible hydroelectric dams, although Vermont eliminated the size cap under its voluntary program. The map

below shows major Canadian facilities that could export electricity to the northeastern U.S. market. Hydro Quebec, the publicly-owned utility for the province of Quebec, currently exports about 16% of its power outside the province, and counts on growing U.S. markets to support future planned development. Hydro-Quebec electricity flows to northern New England across two direct interconnections in northern Vermont – at Highgate (capacity 218 MW and dedicated to long-term Vermont contracts for about 1,577 GWh of power annually) and at Averill for the Phase I/II line (capacity 2,000 MW but limited to 1,200 by reliability concerns) – plus indirect interconnections via New York and New Brunswick. Since much of this power is sold on spot markets, it is difficult to determine how much is utilized in northern New England. According to DOE, the three states together import 5,996 GWh of power from Canada[32], most of which is likely from HQ.

Landscape Disturbance

Although the primary impacts of a 25% hydroelectricity scenario are felt outside the region of this study, the impacts are significant. In northeastern Canada, Hydro Quebec maintains 579 dams, 97 control structures, and 26 large reservoirs to feed 60 hydroelectric generating stations with a total capacity of nearly 35,000 MW. HQ also markets the power from the 5,428 MW Churchill Falls hydro dam in Labrador. New developments under construction or in the planning stages include the Romaine (1,550 MW), Petit Mecatina (1,200 MW), and Magpie (850 MW) Rivers on the north shore of the St. Lawrence River, a new dam on the St. Marguerite River (440 MW), and upgrades to the Manic 2 and 3 and Tabaret complexes. Future plans to fulfill the development goals outlined in Quebec's Northern Plan call for 3,000 MW of additional development north of the 49th parallel, possibly including the Great Whale and Nastapoka rivers flowing into Hudson Bay.

Approximate area of flooding is 4,526,970 acres for the largest reservoirs of the LaGrande complex plus Manicougan, St. Marguerite, Gouin, and Pipmouacan. In addition, Smallwood Reservoir, which feeds Churchill Falls, floods approximately 1,483,000 acres. In an effort to market its own hydro resource, Newfoundland and Labrador's utility NALCOR intends to construct two more dams on the Churchill River (Gull Island and Muskrat Falls), and transmit the power via Newfoundland and under the St. Lawrence to the maritime provinces and on to Maine. 25% of the three states' projected 2050 electricity would amount to about 7% of Hydro Quebec's current power production (200,764 GWh in 2011), or about 4% for just the incremental expansion above current use.

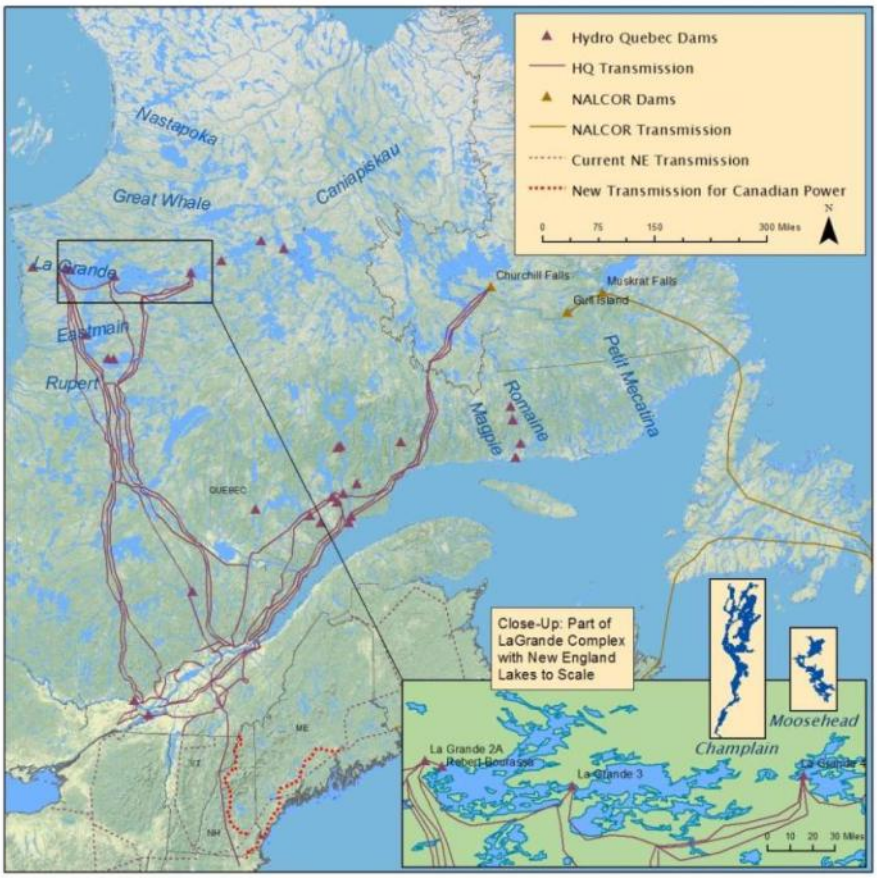
Other impacts from Canadian hydroelectricity:

- Aside from direct destruction of habitat, flooding and other river modifications affect migration routes of caribou and fragment habitat of less wide-ranging species.
- Biologically active mercury levels rise upon flooding and remain elevated for several decades, accumulating at the top of the food chain (including in humans).
- Spawning area for Atlantic salmon is threatened by North Shore river projects.
- Damming, diverting, or augmenting flow disrupts major estuarine waterfowl nesting areas.

Benefits of Canadian hydroelectricity:

- Historically one of the lowest-cost renewable energy options.
- No direct air impacts on site.

Figure 5: Canadian Power to Provide 25% of Northern New England Electricity in 2050



Beyond reservoir flooding, Hydro Quebec projects also affect about 500 miles of river course, partially reversing or diverting flow from the Caniapiscau, Eastmain and Rupert rivers and greatly augmenting the flow of the LaGrande. Conservatively estimated, diversions might affect over 6,000 acres of river area. Since these modifications are much more drastic than the stream flow adjustments for regional hydro, we classify these impacts in the direct column.

Since HQ interconnections through Vermont at Highgate and the Phase I/II DC line through the Northeast Kingdom are already fully allocated, expanding exports to northern New England would require new transmission infrastructure - about twice the capacity of the Northern Pass line proposed for New Hampshire.

Table 5: Disturbance from 25% Imported Canadian Hydroelectricity Scenario

Disturbance	Direct	Total, including indirect
Reservoir flooding	420,698 acres	420,698 acres
Existing transmission	1,463 miles, 26,596 acres	142,910 acres
New transmission	360 miles, 6,545 acres	35,170 acres
Modified rivers	420 acres	420 acres
Total area disturbed*	**454,259 acres**	**599,198 acres**

*43% of scenario quantity already imported.

25% Distributed Solar Photovoltaics Scenario

This scenario is fundamentally different from the others, as it assumes that electricity will be generated near where it is used, eliminating the need for major long-distance transmission upgrades and focusing development on already-disturbed lands. To some extent, wind, hydro and biomass solutions could also follow a distributed energy path. 11,879 MW of solar panels could provide 25% of 2050 electricity. If 30% of the total were mounted on the roofs of buildings, 593,948 2kW units would need to be installed on about 45% of all current homes and 238,767 10kW units on businesses and institutions. 8,315 larger 1MW solar farms located in parking lots, along road rights-of-way, and in other disturbed areas could provide the remaining 70%.

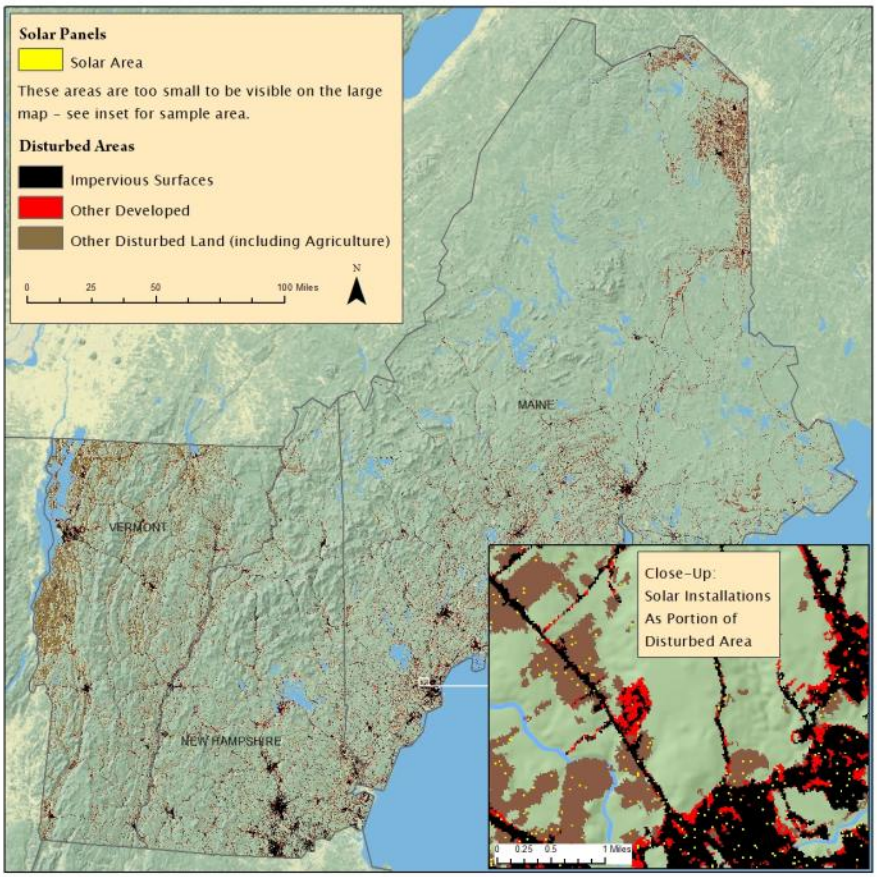
A team convened by The Nature Conservancy delineated disturbed acres where conflicts over energy development might be minimized.[33] The study assumes that disturbance extends 1 kilometer beyond actual disrupted land cover. Categories of disturbed lands range from all disturbed (includes agricultural lands) - to developed (a subset of disturbed that includes mining and changes to topography) - to impervious surfaces (e.g. roofs and pavement).

Table 6: Disturbed Land - Acres and Percent of Land Area

	All Disturbed	Developed	Impervious Surfaces
Vermont	1,247,622	338,026	239,691
	20.3%	5.5%	3.9%
New Hampshire	723,021	444,480	337,805
	12.2%	7.5%	5.7%
Maine	1,564,360	699,845	494,008
	7.6%	3.4%	2.4%
Total	3,535,002	1,482,351	1,071,504
	10.8%	4.5%	3.3%

The map below illustrates the location of disturbed lands – which are correlated with population density and hence electricity load. Approximate area of solar installations is shown in yellow. Data resolution imposes a display scale of at least 1/5 acre, the size of one pixel. An installation of this size (about 40 kW) would be larger than most rooftop PV systems and smaller than many free-standing commercial installations. Hence this map should be taken only as a broad indicator of proportion of landscape affected and not as a depiction of likely locations.

Figure 6 Solar PV Sites to Provide 25% of Northern New England Power in 2050



Landscape Disturbance

3,564 MW of rooftop solar panels on residences and small businesses would require just over 4,000 acres of horizontal surface area, less than 0.4% of the total impervious surface in these three states. Free-standing panels arranged as large solar farms require more space to avoid shading and provide maintenance alleys, so these would require over 62,000 acres. Some of these large arrays might also be mounted over impervious surfaces like parking lots or on the roofs of big box stores and malls; others might be mounted in farm fields or other open spaces. However, acreage needed for large solar farms would amount to only 6% of impervious surfaces, 4% of all developed land, or 2% of all disturbed lands (including agriculture), which would allow for selecting sites with good solar potential where panels would not interfere with desired uses. Table 7 below assumes that only 10% of the solar farm area involves new landscape impacts, with associated indirect impacts occurring mostly on already-disturbed lands.

Other impacts from distributed photovoltaics:

- Land disturbance and air pollution from silica mining outside this region.
- High energy use and toxic air and water emissions during panel manufacturing where panels are produced.
- Large-scale facilities are land-intensive.

Benefits of distributed photovoltaics:

- No air or water impacts on site.
- Location near load minimizes transmission needed.

No major new transmission would be needed, since generation would be concentrated in highly-populated areas.

Table 7: Disturbance from 25% Solar Photovoltaic Electricity Scenario

Disturbance	Direct	Total, including indirect
Rooftop panels	0 acres	0 acres
Large-scale solar farms	6,236 acres	87,308 acres
Total area disturbed*	**6,236 acres**	**87,308 acres**

*Very little capacity currently developed.

25% Demand Reduction for Electricity Scenario

For demand reduction scenarios, we do not produce maps as these options typically have few, or even positive, landscape impacts. A reduction of 14,048 GW in 2050 electricity use would require decreasing electric load by 0.16% each year rather than increasing it by the predicted 0.86%. The big jump in transport and heat conversions built into our scenarios magnifies the challenge. Demand may be reduced using a variety of tools, which include active demand-response, efficiency investments, and changes in user choices (the latter two are sometimes labeled passive demand-response).

Active demand-response is perhaps the easiest to implement at lowest cost. Given the right information (including smart meters) and incentives (including higher prices during peak use periods), electricity users can reduce the need for spinning reserves or quick-start peaking sources by shifting discretionary uses to off-peak hours. Larger users may enter into contracts to shut down energy-consuming processes when requested by the grid operator, which reduces the need for spinning reserves or avoids bringing new sources on-line to meet temporary peaks in usage. Likewise smaller users, more aware of the energy draw from particular appliances and incentivized by tiered prices, can schedule their use during low-demand times of day or reduce their use altogether.

Efficiency investments can deliver the same energy services for less energy input, but generally require an upfront expenditure for improved equipment. These range from energy-efficient light-bulbs, to more efficient machinery and furnaces, to electronic devices that draw less stand-by power. Appliance labeling like the EPA's Energy Star program can support purchase of the most efficient options, even when they cost a bit more.

Changes in consumer choices and behavior can reduce the total need for energy services (choosing smaller electronic display devices or turning off un-needed lights, for instance). Like efficiency solutions, such choices may be supported by better consumer information about energy consumption.

National and regional electricity forecasts tend to neglect the potential for demand reduction – at the state level in Vermont, VELCO projects electricity growth for Vermont at only 0.4% annually through 2030, given an active demand-side program, while ISO-NE projects Vermont growth over the next decade at 0.8%.[34] A recent revision in ISO-NE's model, however, better integrates the effects of demand reduction programs, predicting savings of 215 GWh for these three states by 2021 (savings decline over

time as the easiest measures come first - see Appendix 3). These savings are based on returns to public energy efficiency programs, however, and do not incorporate possible changes in consumer behavior. A 25% drop in projected 2050 demand implies roughly 50 times this level of energy savings per year, which would require dramatic behavioral changes as well as efficiency investments. Allowing energy prices to rise rather than artificially subsidizing them, and educating the public about the high environmental costs of expanded production, would support such an unprecedented shift in consumer choices and business decisions.

Landscape Disturbance

Unlike development of new electricity supply, most demand reduction measures have few deleterious environmental impacts.

Table 8: Disturbance from 25% Electricity Demand Reduction Scenario

Disturbance	Direct	Total, including indirect
Total area disturbed	**~0 acres**	**~0 acres**

Other impacts from demand reduction:

- Energy use to manufacture and transport efficient appliances, machinery, light bulbs, etc.
- Mining impacts for special materials, such as rare earth elements.

Benefits of demand reduction:

- Reduces environmental impacts.
- Saves financial costs in the long run.

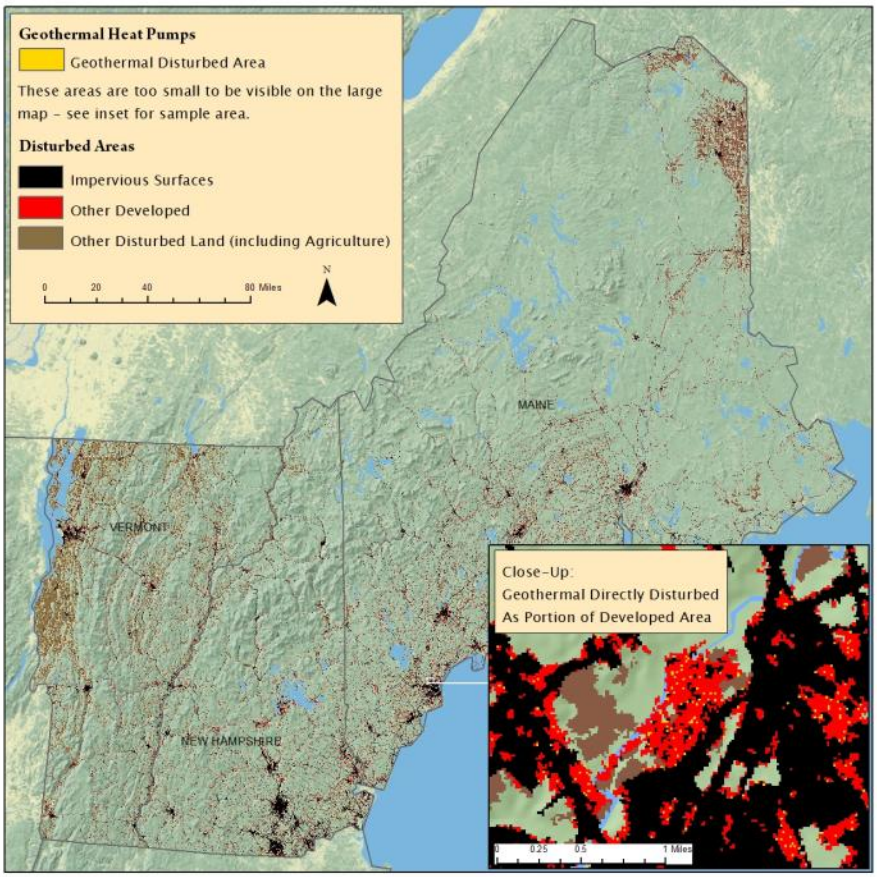
25% Ground-Source Heat Pumps Scenario

Conversion of heat to electrically-powered heat pumps largely shifts the energy burden, with its environmental impacts, to the electricity sector. Ground source heat pumps in our climate produce approximately four times the heat energy that they use in electricity, so electricity usage can be significant. In order to reflect that burden on the electricity sector, we included this scenario as part of the baseline assumptions for all electricity scenarios.

Depending on design (vertical well or horizontal piping) these systems may have negligible or fairly significant landscape impacts, but as for solar PV those impacts will occur in already developed areas. Geothermal heat currently provides about 0.1 trillion Btu. Replacing another 91.5 trillion Btu of heating fuels with heat pumps would require converting all 761,000 homes that currently heat with oil in the three states (accounting for about 76.1 trillion Btu) plus enough additional commercial and industrial buildings to use 15.4 trillion more Btu.

The map below illustrates the approximate surface area required for closed-loop horizontal systems providing 45.8 trillion Btu of heat – shown on developed but not impervious lands. We assume the other 45.8 trillion Btu of geothermal heat installations use a vertical well configuration. Since thermal loops would be installed near existing buildings, but not beneath impermeable surfaces, we show locations on developed lands.

Figure 7 Geothermal Heat Pumps to Provide 25% of Heat/Process Energy in 2050



Landscape Disturbance

Disturbed area for horizontal geothermal systems would total about 26,286 acres, with no new area disturbed for the vertical wells. This acreage amounts to only 6.4% of the 410,847 developed acres in the region that are not impervious surfaces. Since this disturbance would occur in already-developed areas and land could be fully revegetated after installation, we consider this an indirect impact only.

Table 9: Disturbance from 25% Geothermal Heat Pump Scenario

Disturbance	Direct	Total, including indirect
Horizontal systems	~0 acres	26,286 acres
Vertical well systems	~0 acres	~0 acres
Total area disturbed*	**~0 acres**	**26,286 acres**

*Only 0.11% of scenario amount currently in place.

Other impacts from heat pumps:

- Environmental impacts depend largely on the source of electricity to run the pumps.
- Open loop systems use large quantities of groundwater.
- Closed loop systems cool the ground or groundwater slightly in winter and cool it in summer, but any long term impacts are largely unknown.

Benefits of heat pumps:

- Provides summer cooling.
- Low maintenance once installed.

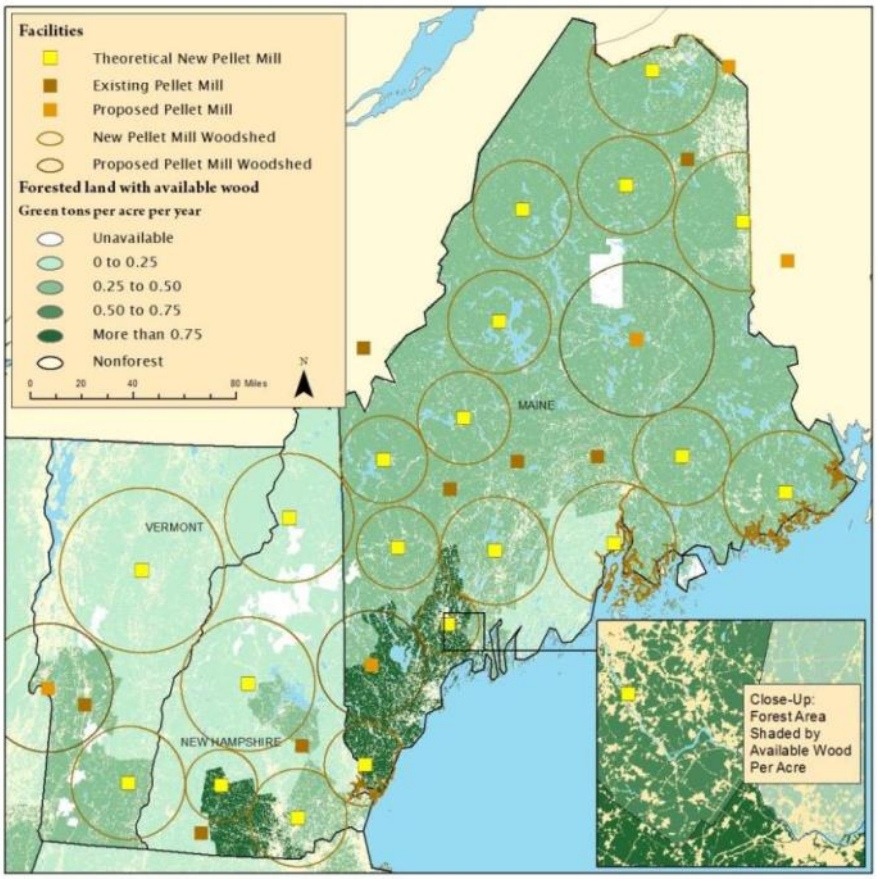
25% Wood-Based Heat/Process Energy Scenario

Beyond conversion to electric sources, renewable options for heat and transport tend to center on biogenic fuels from crops, waste or wood and solar thermal solutions for heating space and water. The electricity scenario showed that sustainable wood supplies were not sufficient to meet 25% of projected 2050 electricity needs for northern New England, so if wood electricity were maximized there would be no wood available for heating or transportation fuels. Policy-makers will need to prioritize uses to get the most energy bang for the limited wood available.

Supply estimates indicate sufficient wood available to provide 25% of projected heat/process energy. This amount of wood heat would require utilizing of 90% to 266% of available supply, depending on the source of supply estimates, and is about triple the current level of wood heat (not counting industrial use by Maine's paper plants). Homes in Vermont (59%), New Hampshire (58%) and Maine (80%)[35] are highly dependent on Number 2 heating oil for space heat, so oil is the most likely fuel to be replaced. The convenience of pellets, and low emissions at the heating site, make it likely that much wood heat expansion will be in the form of pellets.

We assume that 61% of expanded 2050 wood heat is supplied by the 7 existing pellet mills operating at full capacity, plus 3 more proposed and 20 additional new pellet mills, each producing approximately 100,000 tons of pellets annually and all producing for domestic use rather than export. (See Appendix 2 for pellet mill capacities and woodsheds.) The remainder of new wood heat is provided by firewood and chips burned directly in furnaces or boilers. To the extent that chips or firewood provide more than 39% of incremental wood heat, fewer pellet mills would be needed. There is a slight loss of material in pellet making (we assume 2.5%) which means slightly more wood is needed overall. We assume the same amount of energy is required to burn off extra moisture, whether at the pellet plant or in a chip boiler or furnace, so overall conversion efficiency is about the same regardless of the form of wood fuel (air-dried firewood requires no energy inputs for drying, but combustion is slightly less efficient at the stove or furnace). The map below shows existing, proposed and theoretical pellet mill locations, with approximate area of woodsheds assuming exclusive use. See wood electricity section for caveats about wood supply.

Figure 8 Wood Pellet Facilities to Provide (with Firewood and Wood Chips Not Shown) 25% of Northern New England Heat in 2050



Landscape Disturbance

Additional firewood processing or chipping capacity would not require large centralized processing facilities. Wood pellets do require centralized processing and more transport to those facilities and on to retail consumers. 30 pellet mills at about 20 acres each including wood yards would have a direct footprint of 600 acres total. Because pellet mills reach a viable scale at lower wood volumes than for electricity or liquid fuel facilities, woodsheds are relatively small under the heating scenario, averaging a 21 mile radius (see Appendix 2), so total transportation emissions and traffic impacts would be less than for liquid fuels (average 56 mile radius). Transportation for pellets would exceed that for chips or local firewood processing, however, as those omit the middle processing site.

Table 10: Disturbance from 25% Wood Heat Scenario

Disturbance	Direct	Total, including indirect
Facility footprint	600 acres	600 acres
Forest area		26,500,000 acres
Forest access roads	2,739 mile, 7,969 acres	225,790 (included in above)
Total area disturbed*	**17,202 acres**	**26,500,600 acres**

*32% of scenario amount already in place.

Wood for heat or biofuels draws from the same forest base that provides feedstock for electricity generation, so forestland impacts would be very similar. If most new heating uses pellets, there may be limited opportunity to use tops and limbs, since premium pellets require use of the main trunk which produces a cleaner pellet with less ash content. This approach has benefits in that it leaves more tops in the woods to maintain site productivity and wildlife habitat, but it has drawbacks in that it requires more cutting of live trees, with resulting higher net greenhouse gas emissions due to suppressed levels of forest carbon. Pellet technologies could change to accept a broader range of raw materials, so the woodsheds illustrated assume all residues are used by the facilities indicated, with firewood and chips sourced from outside the pellet woodsheds.

Other impacts from wood heat:

- Wood combustion in small devices creates localized air pollution with few pollution control options; small particulates of major concern.
- Forest impacts are similar to those for wood-fueled electricity.

Benefits of wood heat:

- Widely dispersed resource favors local sources for local use, less transport.
- Most efficient energy use for wood.
- Possible forest benefits similar to those for wood-fueled electricity.

25% Demand Reduction for Heat/Process Energy Scenario

Reducing energy demand (or reducing emissions) for heating buildings or fueling industrial processes relies on two factors: 1) using less energy (or lower-emitting fuels) per square foot heated or unit of work performed, or 2) reducing space to be heated or materials to be processed (accomplished by "dematerializing" economic activity, such as by building smaller homes or reducing paper use). Option 1 can be achieved by weather sealing and insulation or switching to more efficient heating appliances or industrial equipment. Passive solar thermal design can also be seen as a way to reduce energy used for space heating by boosting building efficiency. As for electrical efficiency, these approaches require additional upfront investment in exchange for savings over time. Financial incentives, building standards, and educational programs can ramp up energy-reduction efforts and ensure consistent standards and services. Reducing overall need for heat by as much as 25% likely requires changes in behavior and consumer or business choices, including a preference for smaller buildings and a tolerance for lower ambient temperatures or zone heating. The trends have not been favorable to-date. Area of residences per household member in the northeastern U.S. has grown from 826 square feet before 1940 to 1,061 in 2009.[36]

Landscape Disturbance

Landscape impacts from reduced use of space and process heat tend to be neutral or positive. Smaller residential, commercial and industrial buildings help reduce landscape disturbance.

Table 11: Disturbance from 25% Heating Demand Reduction Scenario

Disturbance	Direct	Total, including indirect
Total area disturbed	**~0 acres**	**~0 acres**

Other impacts from demand reduction for heat:

- Energy used to manufacture and transport insulation or other weatherization materials.

Benefits of demand reduction for heat:

- Reduced pollution from fuel combustion.
- Reduced impacts from oil and gas extraction.
- Saves financial costs in the long run.

50% Electric Vehicle Scenario

Since conversion to electric vehicles is one of the few options for reducing GHG emissions from transportation, this scenario doubles the usual share of energy use from 25 to 50%. A shift of this magnitude creates considerable additional demand for renewable electricity, and consequently increases environmental costs. Like electricity-powered geothermal heat, we include this shift in all scenarios to reflect the extra burden on the electricity sector.

Fortunately, electric vehicles are roughly three times as efficient as gasoline motors at converting energy into mechanical motion, so energy inputs are reduced as a result of this conversion. The overall energy advantage is largely cancelled out, however, due to inefficiencies in electricity generation itself.

Landscape impacts

These impacts are largely captured in the expanded electricity sector. Commercial charging stations for vehicles would require some new space, though we assume those would be installed at existing gas stations. Since this affects such a small area, we have not mapped or quantified those impacts.

Table 12: Disturbance from 50% Conversion to Electric Vehicles

Disturbance	Direct	Total, including indirect
Total area disturbed	~0 acres	~0 acres

Other impacts from electric vehicles:

- Impacts depend on the source of electricity.
- Limited life and hazardous waste from batteries.

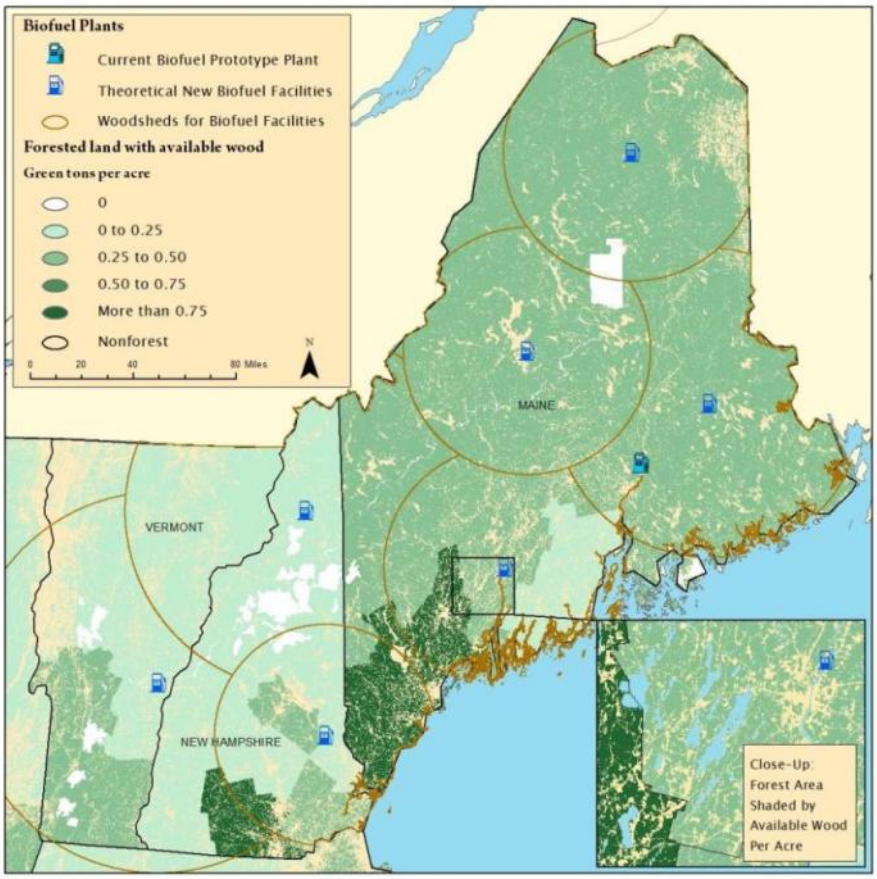
Benefits of electric vehicles:

- Reduces pollution where vehicles are used.
- More efficient than fuel combustion vehicles.
- Smart meters may allow grid to manage vehicle batteries for storage.

13% Wood-Based Biofuels Scenario

In order to replace 39.1 trillion Btu's of liquid transportation fuels (13% of projected 2050 demand), wood-based biofuels such as cellulosic ethanol, biogas or pyrolysis oils would require about 7 plants, each producing 46 million gallons of fuel and using 1.4 million green tons of wood. The map below assumes 4 new plants in Maine, 2 in New Hampshire and 1 in Vermont. (See Appendix 2 for biofuel plant capacities and woodsheds.) Plants are distributed according to currently available forest-based wood supply (assuming sawmill waste is available in the same county where wood volume is cut). Secondary mill and waste wood would also be needed to support this amount of development, leaving *no* additional wood for heating or electricity. Some supplemental material may be available from woody crops on abandoned agricultural land or from dedicated energy crops like switchgrass, though the higher cost of agricultural feedstocks is currently an obstacle.

Figure 9 Biofuel Facilities to Provide 13% of Northern New England Transportation Energy in 2050



Landscape Disturbance

Seven biofuel manufacturing facilities would have a small footprint, slightly larger than individual biomass electricity plants due to the larger volumes of wood processed and more complex processes. We assume each facility requires 75 acres of land. Because of substantial economies of scale for biofuel plants, this option requires the largest woodsheds of any wood energy use.

See wood electricity and wood heat sections for impacts on the forested landscape.

Other impacts from wood-based biofuels:

- Air and water emissions at manufacturing sites.
- Traffic and associated pollution from shipping raw wood and finished fuel. Larger woodsheds than heat or electricity increase this impact.

Benefits of wood-based biofuels:

- See wood electricity and heat sections.

Table 13: Disturbance from 13% Wood-Based Biofuels Scenario

Disturbance	Direct	Total, including indirect
Facility footprint	525 acres	525 acres
Forest area		26,500,000 acres
Forest access roads	2,739 mile, 7,969 acres	225,790 (included in above)
Total area disturbed	**17,127 acres**	**26,500,525 acres**

25% Demand Reduction for Transportation Scenario

Like demand reduction for electricity or heat, reducing transportation energy (or reducing transport emissions) relies on two major factors: 1) fewer miles traveled, and 2) less energy (or lower-emitting fuels) per mile traveled. The first factor requires changes in behavior and consumer choices, including a willingness to walk, bike, carpool, or consolidate necessary trips, and to relocate near work or telecommute. Public transit options are limited in the rural parts of northern New England, but may also contribute in selected popular commuting corridors. The second factor may be addressed by fuel switching (from diesel to natural gas for commercial vehicles, for instance) or improving vehicle mileage through fuel economy standards and higher consumer demand for high-mph vehicles.

Landscape Disturbance

Reduced demand for transport energy creates no direct landscape impacts and may actually reduce overall disturbance. Smart Growth principles that protect open space favor reduced driving and greater reliance on public transit.

Table 14: Disturbance from 25% Transportation Demand Reduction Scenario

Disturbance	Direct	Total, including indirect
Total area disturbed	**~0 acres**	**~0 acres**

Other impacts from demand reduction for transportation:

- Energy used to manufacture new more efficient vehicles and scrap old ones.

Benefits of demand reduction for transportation:

- Reduced pollution from fuel combustion.
- Reduced impacts from oil drilling and refining.
- Saves financial costs in the long run.

Summary of Cumulative Landscape Impacts

The charts and table below summarize the quantitative acreage impacts of the renewable energy scenarios described above. Affected acres are a convenient metric, but they fail to fully reflect comparative impacts - the quality of disruption is equally important. For instance, biomass energy would affect, directly or indirectly, nearly all forest acres in the region. If managed carefully, restricted to appropriate acreage, and subject to uniform and stringent harvesting guidelines, damage to these acres would fall far short of full land use conversion.

Figure 10: Direct Land Disturbance for Electricity Scenarios
(includes existing and new development)

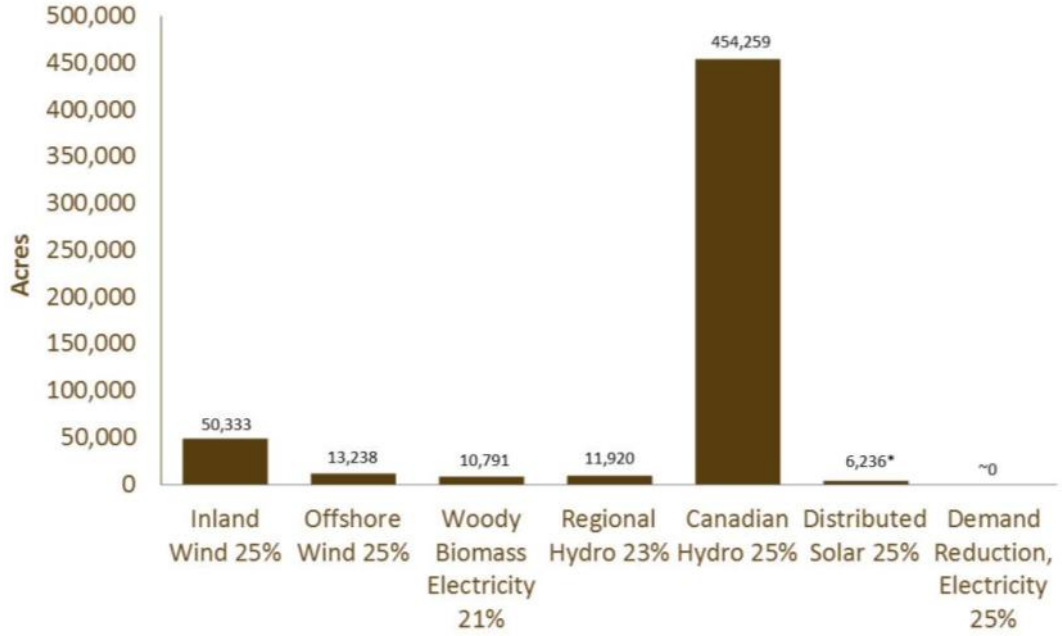
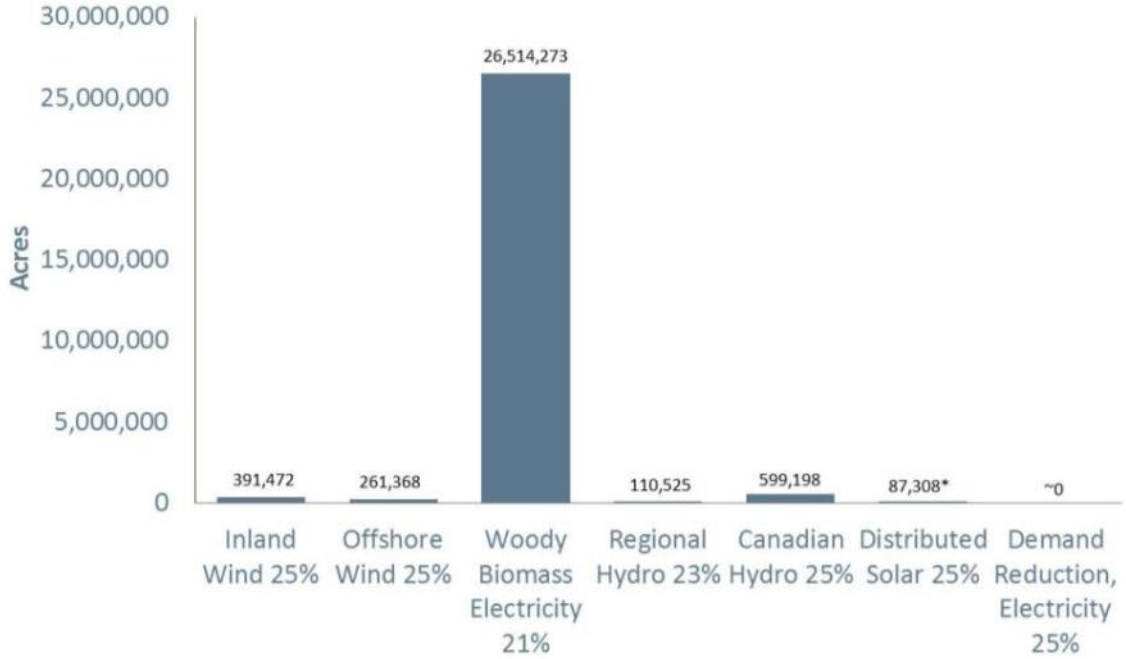


Figure 11: Total (Direct+Indirect) Land Disturbance for Electricity Scenarios
(includes existing and new development, note different vertical scales)



*Solar land area previously disturbed.

Figure 12: Direct Land Disturbance for Heat/Process and Transport Scenarios
(includes existing and new development)

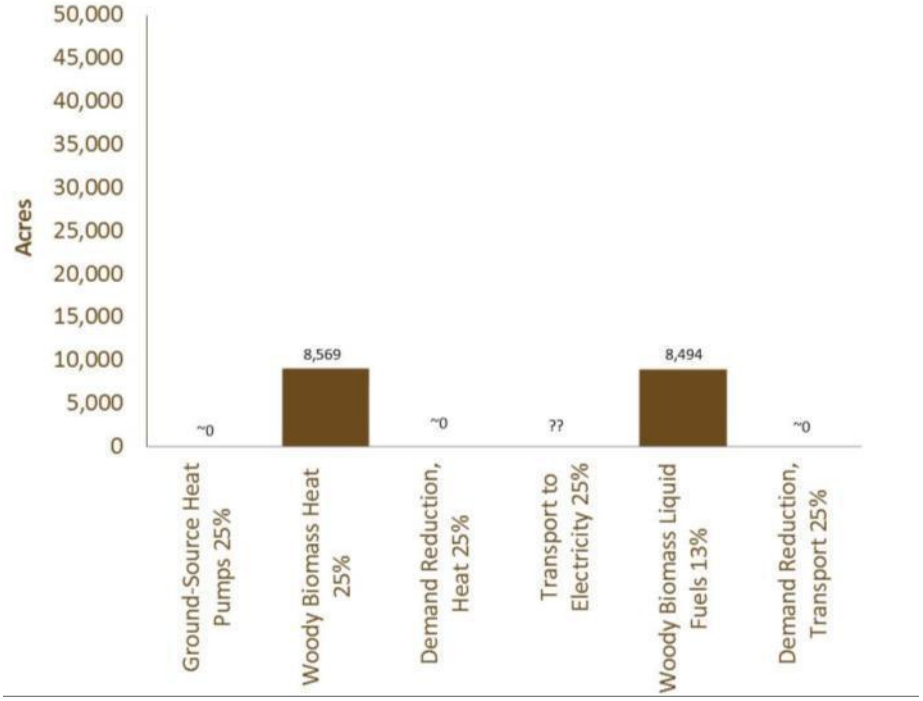
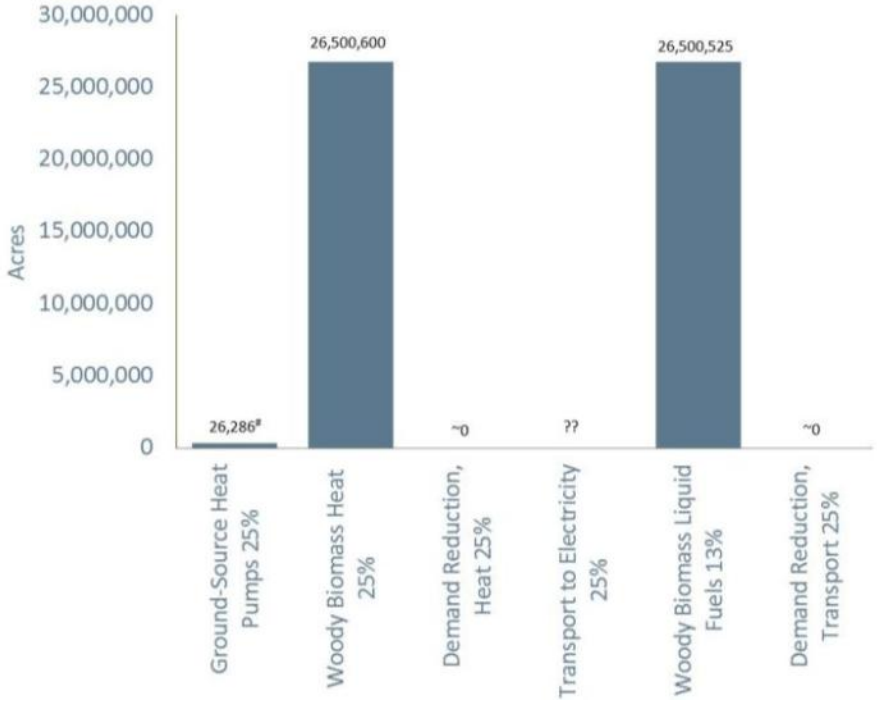


Figure 13: Total (Direct+Indirect) Land Disturbance for Heat/Process and Transport Scenarios
(includes existing and new development, note different vertical scales)



#Heat pump land area previously disturbed and revegetated.

Greenhouse Gas Reductions

In order to balance environmental impacts against climate benefits it is helpful to understand not only the degree of development required to meet GHG reduction targets, but also the extent to which each technology contributes to GHG reduction goals. Reducing greenhouse gas emissions is a primary reason for public policies that encourage development of new renewable energy sources. Maine, New Hampshire and Vermont each endorsed the goals of the New England Governors and Eastern Canadian Premiers to reduce GHG emissions to 75-85% below 2001 levels by 2050. All three states are also members of the Regional Greenhouse Gas Initiative, which will reduce emissions from large power plants to 10% below 2009 levels by 2018. Carbon dioxide emissions from combustion associated with fossil energy use in these three states were about 42.1 million metric tons CO_2 in 2009.[37] Including CH_4 and N_2O, total GHGs from energy combustion would be about 44.6 million metric tons CO_2e,[38] and indirect emissions associated with processing and transport boost the total to about 53 million metric tons CO_2e.[39] If there were no changes from today's energy mix, then growing demand for energy (see assumptions on p. 5) would push the total to approximately 59 million metric tons CO_2e by 2050.[40] Clearly, significant transformations in energy use will be required if the region is to convert this projected increase into a dramatic reduction – emitting only 11.6 million metric tons per year by 2050.

The charts below compare emissions across renewable energy scenarios, including indirect emissions required to manufacture and transport the generating equipment, as well as emissions from land use changes. Figures 14 and 15 show GHG emissions per MWh or MMbtu of energy generated and compare them to emissions from the current mix of sources or high-emission reference sources. See Appendix 4 for computation details.

Figure 14: Greenhouse Gas Emissions from Electricity

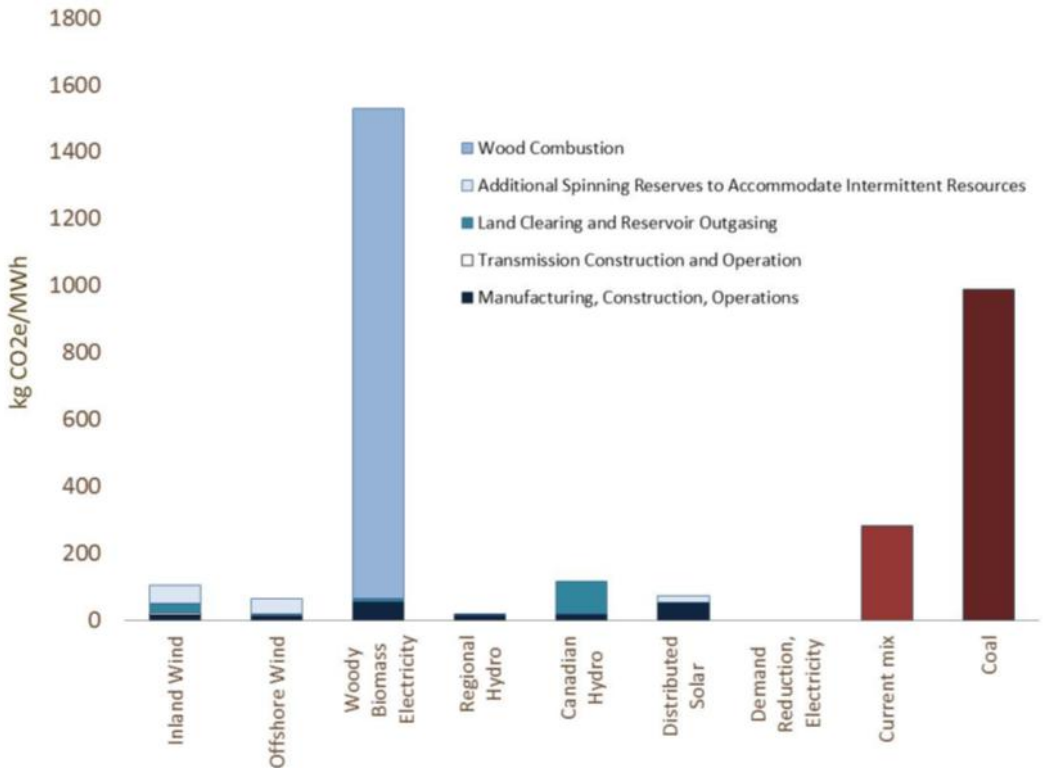
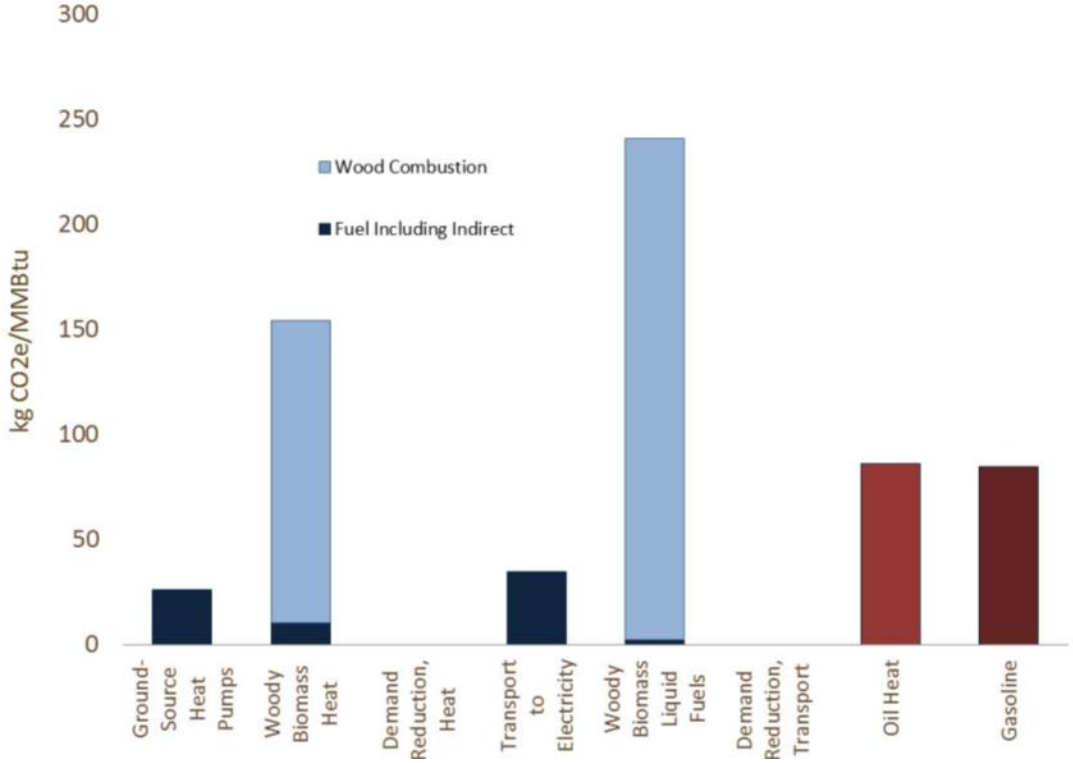


Figure 15: Greenhouse Gas Emissions from Heat/Process and Transport Energy



Tables 15 and 16 show net change in annual GHG emissions due to an incremental increase in each technology above current levels to reach the scenario target. The incremental increase varies across scenarios, as some technologies are already utilized to a greater degree and others have limited development potential. While renewable energy options do release greenhouse gases, in general they will reduce overall emissions by reducing fossil energy use. Table 15 assumes that renewable electricity first replaces coal, then oil, then nuclear (for intermittent sources, this is an optimistic assumption, as wind energy modeling predicts that natural gas will be the primary electricity resource displaced[41]). Table 16 assumes that renewable heat/process energy replaces first oil, then propane; and that renewable transportation energy replaces gas and diesel at their current 80/20 ratio.

Table 15: GHG Emissions Reductions for Renewable Electricity Scenarios

	Inland Wind 25%	Offshore Wind 25%	Woody Biomass Electricity 21%	Regional Hydro 23%	Canadian Hydro 25%	Distributed Solar 25%	Demand Reduction for Electricity 25%
Incremental increase in energy output from this source (GWh)	12,692	14,048	8,418	4,033	8,052	14,048	14,048
Annualized emissions from construction and operation (metric tons)	215,764	182,625	496,670	72,598	161,041	772,642	--
Annualized emissions from transmission construction (metric tons)	93,139	30,831	190	289	20,059	--	--
Land clearing or wood combustion emissions (metric tons)	358,649	91,520	12,384,825	8,019	767,764	--	--
Emissions from natural gas balancing (metric tons)	703,645	637,220	--	--	--	283,208	--
Reduced emissions from replaced sources (metric tons)*	3,486,334	3,512,099	3,405,130	3,321,817	3,398,175	3,512,099	3,512,099
Annual net emissions reduction (metric tons)	-2,115,137	-2,569,904	-2,839,166 to +9,476,554#	-3,240,912	-2,449,311	-2,456,249	-3,512,099

*Assumes that renewables first replace coal, then oil, then nuclear. Wind or solar alone cannot replace baseload coal or oil sources, but combining intermittent sources with natural gas reserves allows them to function similarly to today's baseload sources.
#Range for wood is without or with wood combustion emissions.

Table 16: GHG Emissions for Renewable Heat/Process Energy and Transport Scenarios

	Ground-Source Heat Pumps 25%	Woody Biomass Heat 25%	Demand Reduction, Heat 25%	Transport to Electricity 25%	Woody Biomass Liquid Fuels 13%	Demand Reduction, Transport 25%
Incremental increase in energy output (Trillion Btu)	91.5	61.8	91.6	150.1	39.1	75.2
Annualized emissions from construction and operation (metric tons)	2,380,019#	638,267	--	5,205,696#	97,821	--
Land clearing or wood combustion emissions (metric tons)	--	8,954,096	--		9,395,370	--
Reduced emissions from replaced sources (metric tons)*	7,881,810	5,919,499	7,890,424	12,823,343	3,342,803	6,428,468
Annual net emissions reduction#	-5,501,791 to -6,874,925	-5,223,018 to +3,672,864	-7,890,424	-7,617,648 to -10,621,034	-3,187,033 to +6,150,387	-6,428,468

*Heat replaces fuel oil; transport replaces gasoline (80%) and diesel (20%).
#Range of emissions for heat pumps and electric transport assumes current electricity mix or low-GHG future mix shown in Figure 14 below.

Financial Costs

In addition to landscape impacts and GHG reduction benefits, renewable energy choices will also be influenced and constrained by the financial costs of each alternative. Figure 16 and 17 below compare financial costs per kWh or kWh-equivalent for each scenario (levelized annual cost, including initial investment and annual operating costs). See Appendix 5 for computation details.

Figure 16: Levelized Cost per KWh

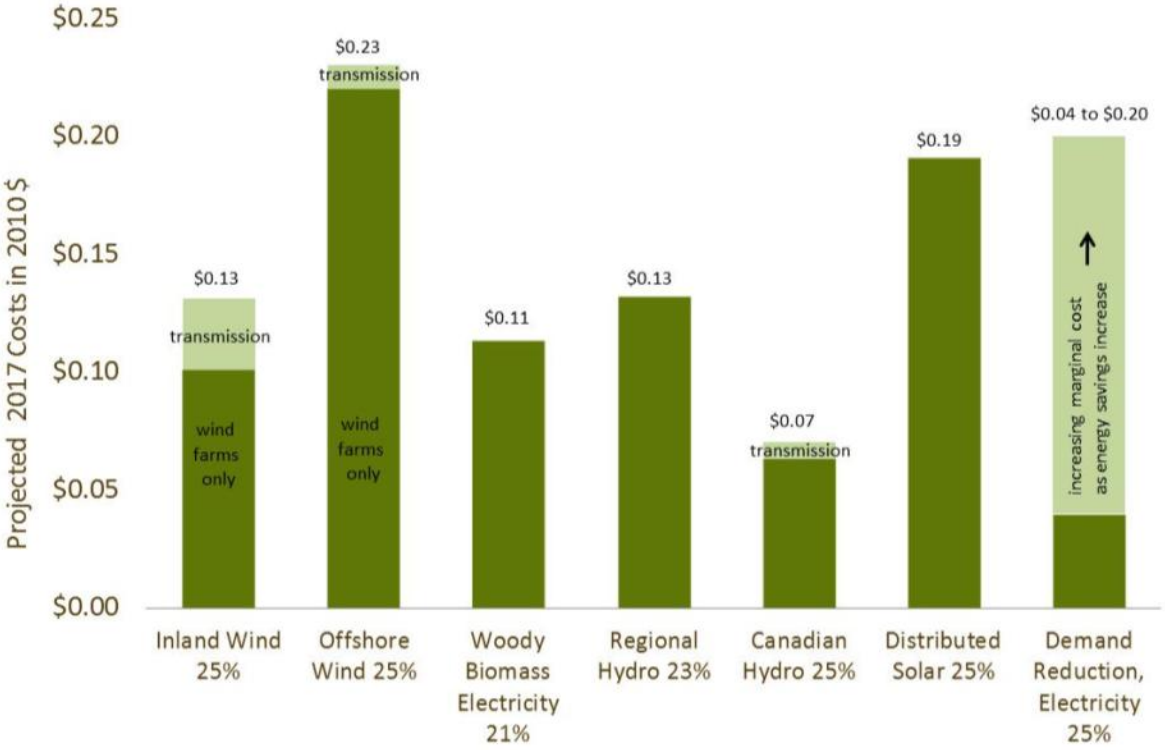
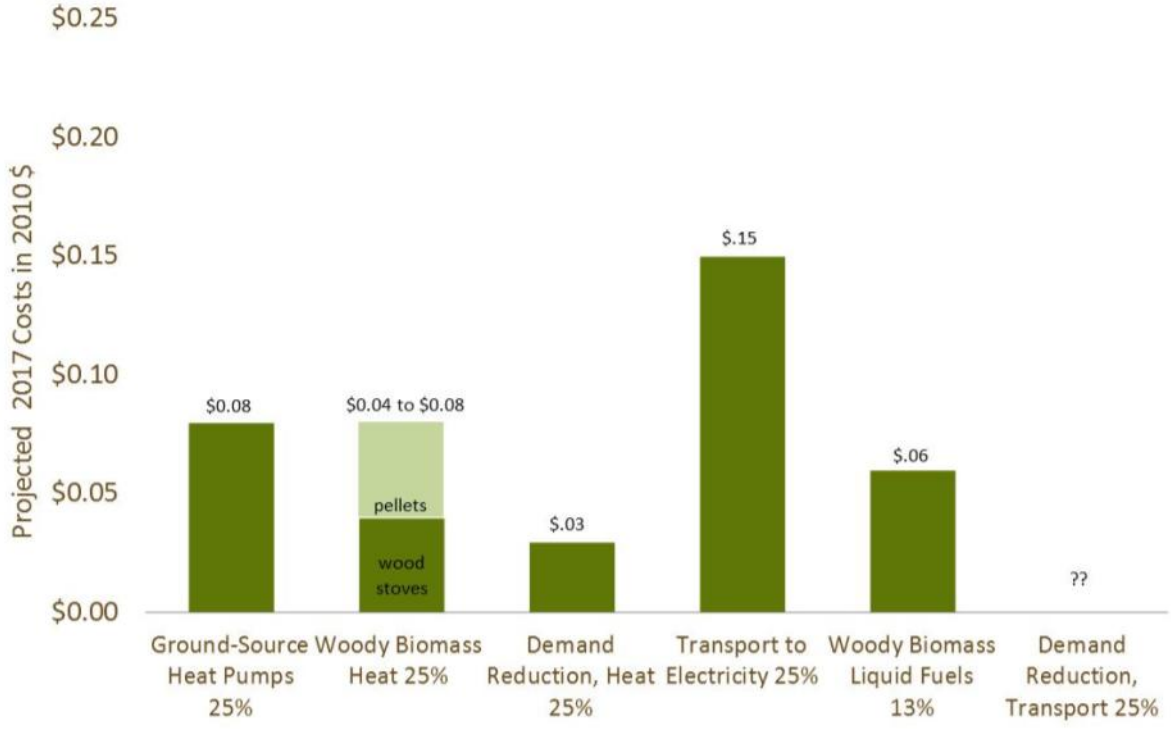


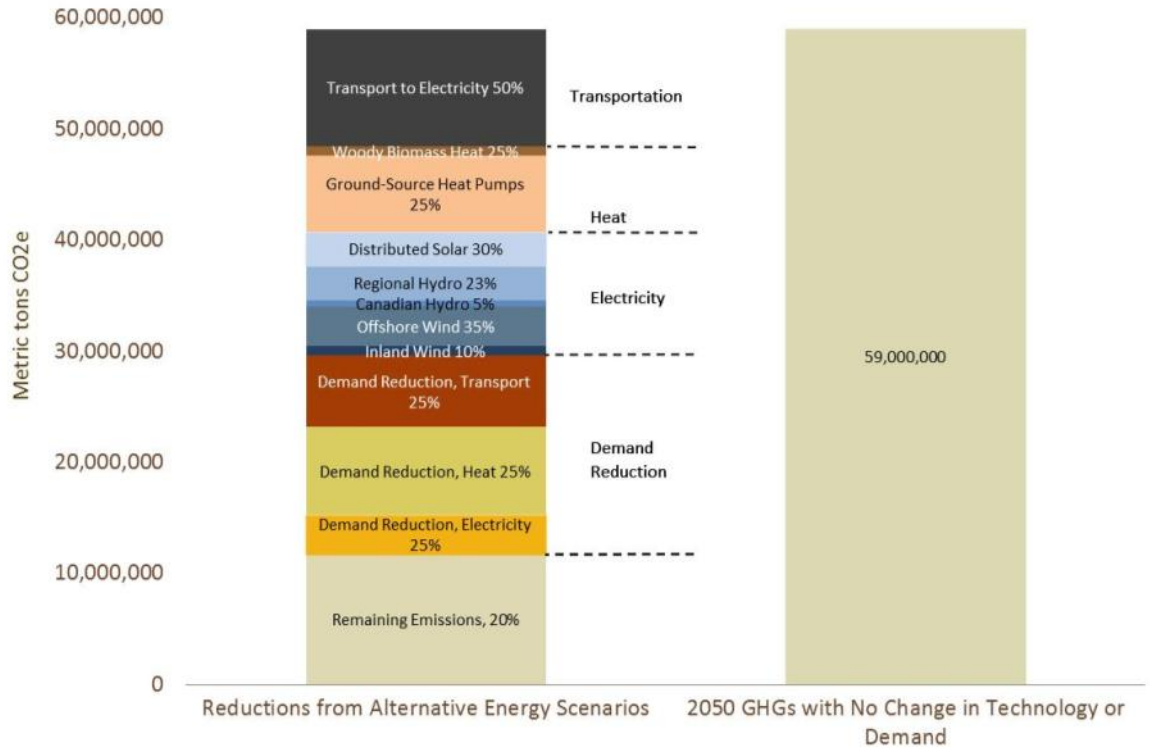
Figure 17: Levelized Cost per KWh-Equivalent



Conclusion

No single renewable energy source can provide all future energy needs for northern New England, nor is any source completely environmentally benign. Future energy choices face inevitable tradeoffs among landscape impacts, greenhouse gas reductions, and financial cost. Figure 18 illustrates one possible combination of options that would achieve an 80% reduction in GHG emissions by 2050, based on emissions reductions presented in Tables 15 and 16. By emphasizing potential reductions in demand, as well as relying on options that cost more financially but have fewer environmental costs, this sample scenario addresses both climate change and landscape impacts. This is just one example, and actually achieving these levels of renewable energy development may not be feasible. Nonetheless, it illustrates the magnitude of change required. The actual 2050 energy mix will reflect a balance among environmental factors, financial costs, and social values.

Figure 18: Sample Combined Scenario to Achieve 80% Reduction in GHG Emissions



Note: Emissions reductions from electric vehicle and heat pump conversions assume the electricity mix depicted in this chart. Woody biomass heat reductions assume half of wood combustion emissions remain in the atmosphere in 2050.

Although every energy solution has its own key costs and benefits, a few broad conclusions might be drawn about particular alternatives.

- Among electricity supply options, local hydroelectricity achieves the best emissions reductions at reasonable cost. Unfortunately, small hydro development in northern New England has limited potential and is subject to extensive federal environmental review (arguably all energy development should be subject to a similar level of review). The current trend is toward removing dams rather

than renovating. Nonetheless, new in-stream and micro-hydro technologies, and innovative approaches to retrofitting existing dams while also providing fish passage, may improve prospects for low-impact hydroelectricity.

- Canadian hydroelectricity offers limited emissions reductions at a low financial cost, but landscape impacts dwarf those of all other alternatives. This option and the wind options involve significant new transmission infrastructure which magnifies both financial and environmental costs.
- Inland wind has reasonable financial costs, but will fragment the most intact remaining wildlife habitat, especially at high elevations, that may offer refuge for sensitive species as the climate warms. Expanded transmission and the need for natural gas reserves also reduce the apparent advantages.
- Offshore wind has almost unlimited potential and relatively low environmental impact, though effects on marine wildlife are poorly understood and costs are currently the highest of any alternative.
- Woody biomass electricity is reasonable in cost due to its proven technology, but if poorly executed may threaten forest health and carbon sequestration services. Electricity from burning wood does not achieve emissions reductions in the short term, and the electricity sector must compete with heating and biofuels for limited feedstocks.
- Solar photovoltaics offer a viable option that minimizes transmission upgrades and can be concentrated on already disturbed lands. The sole obstacle for this option is its high financial cost, but this drawback may disappear if costs continue to fall. If energy prices reflected full external environmental costs, distributed generation alternatives would compare favorably with more disruptive options. Like wind, solar presents some grid integration challenges and requires readily-dispatchable balancing resources like hydro or natural gas.

Considerations for advancing sound renewable energy planning and policy:

- **Local concerns** about energy development impacts should carry due weight in energy siting decisions.
  - *Regional plans often set priorities for protected open space. At the town level, zoning or ordinances relating to energy development are becoming more common. New energy facilities in Maine must comply with local ordinances, while New Hampshire and Vermont currently may permit facilities that fail to comply with local rules or plans if statewide benefits are considered to over-ride local harm.*
- The **full costs** of new energy generation, including environmental costs, should be considered when balancing the benefits and costs of new supply. Downplaying these costs in the interest of rapid climate change action could seriously harm the ability of natural systems to adapt to changes that are already inevitable. Acknowledging them can help focus development on the least harmful alternatives.
  - *Many state policies acknowledge the generally minimal landscape impact of photovoltaics by setting specific solar class targets in RPS, or offering higher compensation for solar projects (e.g. Vermont's standard offer program and net metering solar adder). If offshore wind impacts prove minimal, it might receive similar treatment.*

- Transmission improvements needed to integrate a particular electricity source are often ignored when calculating either financial or environmental costs. Constructing and operating transmission lines adds about 3-11% to GHG emissions from U.S. electricity nationwide, but for countries like Norway with low-carbon electricity, transmission emissions exceed those from electric generation.[42] Expensive transmission grid upgrades have already begun across the region. Such investments could reinforce the current model of large-scale (and, for renewables, often remote) generating units. Alternatively, energy dollars might be dedicated to building a more distributed system.
- Of the heating options considered, ground-source heat pumps and wood heat both save costs over the long term compared to oil heat. Heat pumps require substantial electricity to operate, which puts more pressure on renewable electricity sources, and the initial investment is high compared to other options. The emission reduction benefits of woody biomass heat are delayed by several decades, since wood releases more GHGs than oil in the short run. Of the three energy options that rely on wood, heating uses the least amount of wood, ships wood over shorter distances, and emits the least short-term GHGs relative to the fossil fuel replaced.
- Transportation is perhaps the most challenging energy sector for achieving GHG reductions. Like heat pumps, electric vehicles place more pressure on scarce renewable electricity options. Wood-based biofuels require large centralized facilities and long-distance transport for both wood feedstock and finished fuel, as well as stressing forest capacity. Efficiency of wood energy conversion to biofuels is better than for electricity but lower than for heating uses, and the GHG effects are also intermediate with few net reductions by 2050.

Considerations for advancing sound renewable energy planning and policy:

- **Transmission** planning should take into consideration non-transmission alternatives like distributed generation and demand reduction, and minimize landscape impacts.
  - *ISO-NE has taken steps to better incorporate demand-side solutions in its transmission planning, but still encourages transmission over other solutions by sharing the costs of many power lines across the region.*
  - *New Hampshire determined that the proposed Northern Pass transmission line, a merchant line not required for grid reliability, may not use eminent domain to override local siting concerns.*
- To achieve needed GHG reductions at lowest financial and environmental cost, **heating and transportation** energy should receive equal attention with electricity.
  - *New Hampshire now credits limited amounts of renewable thermal energy toward its RPS targets.*
  - *Vermont is considering the design of a "total energy standard".*
- Energy policies aimed at addressing climate change should use accurate life-cycle **greenhouse gas accounting** that includes impacts on terrestrial carbon stocks and changes in grid operation to accommodate intermittent resources.
  - *Massachusetts' RPS regulations now require documented GHG reductions for eligible biomass facilities.*
  - *GHG effects of new wind facilities should be estimated by modeling grid response to cumulative wind capacity rather than output times average grid emissions.*

- Across all use sectors, reducing demand achieves the greatest emission reductions and avoids the serious environmental impacts of nearly all supply-side approaches. It appears that reductions on the order of 25% across all energy sectors should be achievable at costs below most renewable energy supply options. Unfortunately, demand reduction measures are often considered feasible only if they are "cost-effective" – meaning the cost of efficiency measures must be less than the cost of the energy saved over time. Results depend heavily on the expected price of energy, as well as on the assumed discount rate (which affects how we weigh future savings against current costs) and on the valuation of environmental externalities. Including external costs in energy prices, and using a lower "social discount rate" that reflects an equal voice for future generations, would expand the range of cost-effective efficiency options by reflecting true energy costs.
- Efficiency measures are also typically limited to investments that maintain the same level of service with less energy input. Adapting to ecological limits may require a shift in social priorities to emphasize quality-of-life values like leisure time and local community interaction rather than energy-intensive consumption. Energy-reducing choices and behavior will almost always save money rather than costing more, but old habits die hard.

Considerations for advancing sound renewable energy planning and policy:

- Measures that **reduce energy demand** should be subsidized at least as heavily as new energy supply. Most state efficiency programs limit investments to those considered cost-effective, without fully accounting for external environmental costs. Likewise, RPS programs generally focus on new supply, which can actually discourage efficiency investments.
  - *Least cost integrated plans required for Vermont utilities theoretically include efficiency on an equal basis with supply, and also consider environmental as well as financial life-cycle costs. Vermont's energy siting statute also requires a proposed facility to meet a need that cannot be addressed by "energy conservation programs and measures and energy-efficiency and load management measures" at a comparable financial and environmental cost. Other states lack these mandates, and in Vermont they are seldom applied rigorously.*
  - *North Carolina allows utilities to meet their RPS obligations through energy efficiency (up to 25% of target) or demand management (up to 100% of target).*

In the quest for climate friendly energy solutions, all supply-side approaches currently have significant environmental and/or financial costs. Understanding those costs is a prerequisite for prioritizing the least damaging options, or for minimizing or mitigating unavoidable harm. When faced with choices among renewable energy alternatives, policy incentives can guide investments toward those options with least environmental impact and associated external costs. Full recognition of the environmental impacts of renewable energy development can also help bolster public and private resolve to reduce energy use. This paper introduces a framework for understanding those impacts, and we invite corrections and supplements to flesh out the information presented here.

Appendix I: Estimating Acres Affected

Inland Wind

- Ridgeline Development - 17 wind projects that are currently operating and 25 proposed across the three states require total ridgeline development of 229 miles (a mean of 1,296 feet of ridgeline distance per turbine for 948 total turbines). Assuming that the 21 additional theoretical sites required to reach the 25% goal (1,034 additional turbines at about 49 turbines per project and 3MW turbines) have similar turbine spacing, they would cover 254 additional miles of ridgeline.[43] Total ridgeline development with current, proposed and new wind sites would be 483 miles – more than the distance from the northeastern tip of Maine to the southwestern corner of Vermont. Each turbine pad requires clearing of about 2.5 acres[44], for a total of 4,955 acres permanent clearing. Most pads require blasting or filling to achieve sufficient level surface areas. 100-400 tons of concrete is poured for each turbine foundation[45], though ridgeline projects anchoring to ledge may use less.
- Roads
  - "Crane paths" along ridges are approximately 34 feet wide, with additional disturbed width for cut and fill operations. In order to accommodate transport of long turbine parts, irregular ridgelines require extensive blasting and filling to smooth dips and curves. Total crane path length would be similar to ridgeline length at 483 miles or 1,990 acres permanent clearing (483 miles x 5,280 $^{ft.}/_{mile}$ x 34 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$). Not all fill slopes, drainage ditches, and stormwater features will be revegetated, so total permanent clearing associated with ridgeline roads will be somewhat more than this.
  - Access from nearby public roads is needed for installation and maintenance. A sample of 12 current or proposed projects with mapped access routes requires 35.5 miles of roads to access 248 turbines. Some of these are logging roads that require upgrading, rather than entirely new road miles. Using the shortest distance from turbine string to the nearest road as a conservative approximation of access road length, access roads for all current and proposed projects would total 41 miles, or 0.04 $^{miles}/_{turbine}$, and roads for the 1,982 turbines needed to reach the 25% goal would total about 79 miles. At 24 feet average width (18 foot wide roadbed plus cut-and-fill and pull-outs for passing) access road clearing would total 230 acres (79 miles x 5,280 $^{ft.}/_{mile}$ x 24 ft. wide ÷ 43,560 $^{sq.ft.}/_{acre}$). As for ridgeline roads, unvegetated cut and fill slopes, ditches and stormwater features would increase this acreage.
- Transmission
  - Each project requires new local transmission to connect the project to the grid. Some lines might parallel access roads, but the most direct route may also dictate separate corridors for road and transmission access. A sample of 15 existing or proposed projects (total capacity 1,027 MW) with mapped transmission lines required 122 miles of connecting transmission. Using the shortest distance from turbine string to the nearest mapped high-voltage transmission line as a conservative approximation of connecting transmission line, transmission connectors for all current and proposed projects would total about 282 miles, or 0.12 miles per MW, and at this same rate transmission lines for the 5,346 MW needed to reach the 25% goal would total about

641 miles. At 50 feet average width of cleared corridor, connecting transmission line clearing would total 3,885 acres ((641 miles x 5,280 $^{ft.}/_{mile}$ x 50 feet wide) ÷ 43,560 $^{sq.ft.}/_{acre}$).

- Wind development must occur in areas of concentrated wind resource, and in this region those areas frequently lack sufficient network capacity to absorb new production of the magnitude envisioned in this scenario. An ISO-NE study for the New England Governors indicated that about 4,320 miles of new high-voltage transmission line would be required for New England wind development similar in magnitude to the 25% scenario considered here.[46] Assuming for this scenario that most of the energy is used within northern New England rather than exported to the south, we assume that only 50% of the envisioned new transmission network is needed. High-voltage lines with a 150 foot right-of-way (Northern Pass proposed minimum width) would require clearing 39,273 acres (2,160 miles x 150 ft. x 5,280 $^{ft.}/_{mile}$ ÷ 43,560 $^{sq.ft.}/_{acre}$).

- Total direct impact area depends on terrain and configuration of turbines. A National Renewable Energy Laboratory study assessed land impacts of operating wind farms. Those using a single string configuration, typical of northern New England wind farms, averaged 3.3 acres of clearing per MW of capacity.[47] Selected projects constructed to-date in this region vary from much less to much more than this average.

Acres Disturbed for Selected Wind Projects in Northern New England

	Turbine Size (MW)	Total MW	Acres Cleared per MW
Kingdom Community Wind, VT	3	63	2.3
Granite Reliable, NH	3	99	2.0
Bowers, ME	1.2 and 3	69	5.4
Spruce Mountain, ME	2	20	5.1
Mars Hill, ME*	1.5	42	0.78
Stetson Mountain, ME*	1.5	57	3.4
Kibby, ME*	3	132	0.76
National average for turbines in			3.3

*Part of nation-wide NREL study.

- Concentrating wind development at a single contiguous site would make for relatively low impact at about 56,915 acres (3.3 $^{acres}/_{MW}$ x 5,346 MW plus 39,273 acres for transmission). But by nature wind development in this region must be widely disbursed and is often distant from load. If the zone of indirect impact reaches 1,000 feet on either side of the developed ridgeline (setback recommended by Maine's Office of Energy Independence and Security to protect from noise and ice throw[48]), and 328 feet (100 meters, commonly used to define interior forest habitat[49]) on either side of access roads and transmission corridors, then total impacts would affect nearly 400,000 acres. Many of these affected acres would be within the largest remaining intact blocks of wildlife habitat in the northeastern U.S., which tend to be at high elevations due to difficult access, and would disrupt east-west migration corridors.
    - 119,081 acres (483 miles x 5,280 $^{ft.}/_{mile}$ x 2,034 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) for ridgeline;
    - 6,512 acres (79 miles x 5,280 $^{ft.}/_{mile}$ x 680 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) for access roads;
    - 54,854 acres (641 miles x 5,280 $^{ft.}/_{mile}$ x 706 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) for connector transmission;

- 211,025 (2,160 miles x 5,280 $^{ft.}/_{mile}$ x 806 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) for new high voltage lines

Offshore wind

- 800 turbines with 6 paired cable anchors each would disturb about 44 acres of ocean floor (800 x 400 sq. ft. per anchor x 6 ÷ 43,560 $^{sq.ft.}/_{acre}$) spaced across 184,960 acres of total area;
- Collecting lines within each wind farm from turbines to an offshore substation total approximately 200 miles;
- Trunk lines of approximately 20 miles each would connect offshore wind farms to the grid. 80 miles of buried cable with 20 foot wide excavation zone 3 to 10 feet deep would directly disturb about 194 acres (80 miles x 5,280 $^{ft.}/_{mile}$ x 20 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) of ocean floor. If the total indirect impact zone is 328 feet on either side of the buried cable, total affected acres would be 6,555 acres (80 x 5,280 $^{ft.}/_{mile}$ x 676 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).
- Transmission improvements onshore for the 4,000MW offshore wind case in the ISO-NE 2030 study (which locates most sites in MA and CT) include 1,430 miles of new transmission at a cost of $6.1 billion. Assuming as for the inland scenario that only half is needed to power northern New England alone, direct land clearing for new high-voltage transmission would be about 13,000 acres (715 miles x 5,280 $^{ft.}/_{mile}$ x 150 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) and indirect impact about 69,853 acres (715 miles x 5,280 $^{ft.}/_{mile}$ x 806 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).

Woody biomass electricity

- For the footprint of the facilities themselves, we assume 50 acres per plant including wood storage yards (estimated from satellite imagery of existing plants), 1,150 acres total for the added plants.
- 10.6 million tons of additional low-grade wood must be harvested to support the proposed and new plants shown. The increase amounts to 53% of current harvest volume, which is about 19.9 million green tons for the three states (Maine = 14.59 million green tons; Vermont = 2.46 million green tons; New Hampshire = 2.8 million green tons[50]).
- Based on Forest Inventory and Analysis estimates, 2.3 million acres of timberland in these three states are more than 1 mile from an existing road. The FIA definition of road is restricted to improved roads (graded, ditched, etc.), so some of these areas have logging road access. If half these areas had limited access, and new roads were constructed in these areas at the average density for nonwilderness portions of National Forests (1.52 miles of road per square mile) and roads were 24 feet in width, new access roads would clear about 7,969 acres (1,153,418 acres ÷ 640 $^{acres}/_{sq.mile}$ x 1.52 $^{miles\ road}/_{square\ mile}$ = 2,739 miles of road x 5,280 $^{ft.}/_{mile}$ x 24 ft. wide ÷ 43,560 $^{sq.ft.}/_{acre}$). Indirect road impacts would affect about 225,790 acres (2,739 miles x 5,280 $^{ft.}/_{mile}$ x 680 ft. wide ÷ 43,560 $^{sq.ft.}/_{acre}$), but this area is already included as part of general forest indirect impacts.
- 144 miles of new connecting transmission line, with clearing at 50 feet width, would affect 872 acres (144 miles x 5,280 $^{ft.}/_{mile}$ x 50 ft. wide ÷ 43,560 $^{sq.ft.}/_{acre}$). Indirect effects would total 12,323 acres (144 miles x 5,280 $^{ft.}/_{mile}$ x 706 ft. wide ÷ 43,560 $^{sq.ft.}/_{acre}$).

Regional hydroelectricity

- We estimate direct impact from pre-existing hydro dams as the area of reservoirs. Since there are no consistent data on reservoir area, we selected all water bodies with the word "reservoir" in their

name from the Census TIGER data files for water (86 reservoirs) and calculated total area (10,781 acres). Since not all reservoirs are used to generate electricity, this may exaggerate impact, but we did not include impacts from roads or transmission to service these dams. This may be an overestimate, as some existing reservoirs are no longer used to generate hydropower. According to a recent DOE analysis, conventional hydroelectricity in the northeast disturbs 0.91 m^2 of land per MWh generated (assumes a capacity factor of 52% compare to our assumed factor of 43%), or about 3,000 acres for the hydro power used in Vermont, New Hampshire and Maine.[51]

- Direct impact (clearing and ground disturbance) from new hydro facilities would amount to about 31 acres (400 sq.ft x 3,364) for power houses, 631 acres for penstocks of 6 foot width (868 miles x 5,280 $^{ft.}/_{mile}$ x 6 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).
- Based on the minimum distance from penstock to the nearest road, 3,364 projects with 830 MWa of capacity would require 328 miles of access road, though these could be narrow(we assume 12 feet) to access such small sites. Assuming transmission runs along the access road, direct land disturbance for roads and transmission would total 477 acres ((328 miles x 5,280 $^{ft.}/_{mile}$ x 12 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).
- River reaches with reduced flow would be slightly more than penstock length due to sinuous stream paths (assume 1.25x), with more width (assume 20 ft.), perhaps amounting to 2,630 acres of stream affected (868 miles x 1.25 x 5,280 $^{ft.}/_{mile}$ x 20 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$). Overall indirect impact area totals the 2,630 acres of affected stream channel plus a 328 foot wide impact zone for penstocks, roads and transmission: penstocks 69,650 acres (868 miles x 5,280 $^{ft.}/_{mile}$ x 662 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$) and roads and transmission 27,433 acres (328 miles x 5,280 $^{ft.}/_{mile}$ x 690 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).

Canadian hydroelectricity

- Hydro Quebec reservoirs cover an area of 6,009,970 acres. 7% of the flooded area (required to meet the 25% target) is 420,698 acres, and 4% (incremental increase over current use only) is 240,399 acres.
- Existing transmission totals approximately 20,897 miles of high voltage transmission line with 150 foot right-of-way, affecting about 379,945 acres (20,897 miles x 5,280 $^{ft.}/_{mile}$ x 150 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).[52] 7% of this would be 26,596 acres affected for total use, and 4% would be 15,198 acres for incremental only. Indirect impacts for existing transmission extending to a 328 foot wide buffer would affect 2,041,574 acres (20,897 miles x 5,280 $^{ft.}/_{mile}$ x 806 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$). 7% of this would be 142,910 acres and 4% 81,663 acres.
- 360 miles of new line with 150 foot right of way would directly affect another 6,545 acres, with indirect impacts extending 328 feet to each side totaling 35,170 acres (360 miles x 5,280 $^{ft.}/_{mile}$ x 806 ft. ÷ 43,560 $^{sq.ft.}/_{acre}$).

Distributed solar photovoltaics

- Each 1 kW solar panel generates about 1.135 MWh per year under typical northern New England conditions[1]. If mounted at 45°, each 1 kW panel would take up 50 square feet of area horizontal to

[1] Based on actual conditions for a net-metered panel in Craftsbury, VT - implying conservative 13% capacity factor.

the ground, so 3,564 MW of rooftop panels would require 4,091 horizontal acres of rooftops (3,564 x 50,000 $^{sq.ft.}/_{MW}$ ÷ 43,560 $^{sq.ft.}/_{acre}$).

- Large free-standing solar farms typically require 5-10 acres per MW.[53] 8,315 MW of ground-mounted panels would require 62,363 acres, but we assume only 10% of this represents direct impacts causing land use changes. If solar farms average 1 MW and 7.5 acres each, indirect impacts extending 328 feet on all sides would total 10.5 acres per farm or 87,308 acres total.

Ground-source heat pumps

- Depending on design (vertical well or horizontal piping) these systems may have negligible or fairly significant landscape impacts, but as for solar PV those impacts will occur in already developed areas. Horizontal systems with 1,000 feet of piping spaced 2.5 feet apart require 2,500 square feet of disturbed area, for a total of 52,571 acres disturbed (equivalent of 916,000 residences x 2,500 sq.ft. ÷ 43,560 $^{sq.ft.}/_{acre}$). Assuming half the systems are vertical water-based systems, the acreage would be half of this, 26,286 (6.4% of the 410,847 "other developed" acres in the region – assuming that piping will not be installed under impervious surfaces).

Wood-based heat/process energy

- 30 pellet mills with a footprint of about 20 acres each for facilities and wood yard would affect 600 acres total.

- For impacts from new woods roads, see woody biomass electricity.

- Woodsheds are relatively small under the heating scenario, averaging a 21 mile radius (see Appendix 2), so total transportation emissions and traffic impacts would be less than for the electricity scenario (32 mile radius) or liquid fuels (56 mile radius). Woodsheds, and hence transportation impacts, for pellets would exceed those for local firewood processing.

Transportation biofuels

- Seven biofuel manufacturing facilities would have a small footprint, about 70 acres at 10 acres each. If large wood storage yards are required to even out seasonal supply, acreage could increase.

- For impacts from new woods roads, see woody biomass electricity.

- Woodsheds are large under the liquid fuels scenario, averaging 57 miles (see Appendix 2), so total transportation emissions and traffic impacts would be highest of the three wood energy scenarios.

Appendix 2: Delineating Woodsheds and Estimating Wood Quantities

- All GIS steps described here use ArcGIS software. Select counties within 50 miles of VT/NH/ME border from ESRI county detail shapefile, export to new shapefile (nne50milectys), and use conversion tool "Polygon to Raster", with NLCD raster for reference cell size, to construct a raster with county fips code as value (ctyfor). Add fipsn number field and calculate fips as a number from fips as text, then use "Lookup" tool to enter fipsn in the number field of a new raster (ctyne);
- Use NLCD 2006 data to delineate forested lands that might produce wood fuel.[2] Since wood flow is based on county-wide averages, assigning wood flows to only the forested portions of the landscape avoids inclusion of significant developed areas or large water bodies within defined woodsheds. The NLCD 2006 land cover data from the USGS was the best available and most recent dataset with consistent coverage across the three-state region. The data is considered "provisional" pending completion of the accuracy assessment. It is possible that some areas classified as forest capable of providing fuel wood are actually nonforested, and vice versa. Fortunately, the discrimination of forest cover from other cover types needed for this report is typically strong in land cover classifications of Landsat satellite data. The greater inaccuracies arise from discrimination between forest types or between other types of vegetative communities not used for this work. Since the BTS Update estimated wood flows at the county level, incorrect land cover classification may affect the size of individual woodsheds, but would not affect the total potential scope of woody biomass energy development across the entire three-state region.
- Clip land cover to nne50milectys shapefile (nlcdnne); select forested pixels using "Extract by attributes" with values = 41 deciduous, 42 coniferous, 43 mixed, 52 shrub-scrub (to incorporate regenerating forest), or 90 woody wetland) (forcodenne). Use "Reclassify" to create new raster (fornne) with value =1 for each forested pixel and "No data" for nonforest pixels;
- Use "Con" tool to construct raster (forfips) that substitutes numeric fips code for value=1 for forested pixels, with no data for non-forest pixels,[3];
- Use "Con" tool to substitute 0 value for pixels that are protected land (wilderness, 2001 USFS roadless, National Parks);
- Export zip codes with number of forested pixels as text to Excel workbook btsberc, worksheet forest;
- In BTS Access database, query feedstocks by county [combined management regime = residues alone on half and integrated harvest from thinnings+residues on half (limited by 2006 state harvest volume for sawlog/pulp portion of integrated harvest - substitute all residues from current harvest if greater than combined) + other removals (mostly land clearing) + pulp diversions + primary mill residue]. Export to btsberc workbook with separate worksheet for each feedstock;
- In Excel, sum total green tons[54] woody biomass by county, multiply BTS dry ton values by 2 to approximate green tons, divide county feedstock total by forested pixels in county to get wood supply per forested pixel in each county;

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[2] Fry, J., Xian, G., Jin, S., Dewitz, J., Homer, C., Yang, L., Barnes, C., Herold, N., and Wickham, J., 2011. Completion of the 2006 National Land Cover Database for the Conterminous United States, *PE&RS*, Vol. 77(9):858-864. Data downloaded at http://www.mrlc.gov/nlcd2006.php. Satellite imagery from 1999-2003

[3] Table must be DOS text file.

- In bts_fips_table worksheet, look up gtpix (green tons per pixel) by fips, multiply by 1,000,000 to make gtpix value an integer, change fips and gtpix to number field and save as MS-DOS text file;
- In Arcmap, substitute county-level per-pixel green tons biomass for fips code in forested pixels, using "Reclassify by table" (ctywood);
- BTS theoretically accounts for only newly available wood, so wood used by existing facilities has already been deducted. Analysis considers only proposed and theoretical new facilities needed to meet 25% goal. Buffer each selected new facility with approximate woodshed radius, extract ctywood raster by woodshed polygon, add MULT field and calculate as (Count*Value) ÷ 1,000,000. Sum MULT field to get available wood in woodshed. Adjust buffer until supply approximately matches need for each theoretical plant.
- For overlapping woodsheds, do most likely plant first, then deduct that woodshed from the next most likely before calculating available wood (make buffer circle larger to accommodate the deduction, union overlapping buffers, select new woodshed segment excluding previous plant woodshed, export to new shapefile, and use this segment to extract raster values). To translate per-pixel values to green tons per acre for legend, multiply by 4.5 (there are approximately 4.5 30x30m pixels per acre) then divide by 1,000,000 to account for per-pixel factor being a million times the actual value.

Electricity plant capacity, wood use, and woodshed diameters

Facility	MW	Wood Use (green tons/year)	Woodshed Diameter (miles) [Many circles truncated by state border]
Aroostook1, ME	44	436,949	36
Aroostook2, ME	58	584,992	50
Aroostook3, ME	33	332,997	26
Piscataquis1, ME	42	423,184	30
Piscataquis2, ME	32	319,629	26
Piscataquis3, ME	42	416,792	30
Washington, ME	33	326,212	30
Hancock, ME	43	428,405	40
Somerset, ME	34	336,527	26
Kennebec, ME	33	334,473	30
Franklin, ME	52	520,291	37
Lincoln, ME	30	298,585	30
Cumberland, ME	59	587,494	25
York, ME	50	502,294	20
Belknap, NH	23	233,690	30
Rockingham, NH	51	508,025	35
Lamoille, VT	33	331,406	50
Total: 18	**692**	**6,921,945**	**32 average**

Pellet mill production, wood use, and woodshed diameters

Facility	Wood Pellets (dry tons/year)	Wood Use (green tons/year)	Woodshed Diameter (miles)
ME1	108,406	222,232	25
ME2	100,690	206,414	27
ME3	102,900	210,946	19
ME4	108,163	221,735	20
ME5	99.842	204,676	18
ME6	100,183	205,376	24
ME7	108,371	222,161	19
ME8	103,057	211,266	24
ME9	102,655	210,442	16
ME10	100,986	207,022	12
ME11	102,903	210,952	16
ME12	98,296	201,506	17
ME13	107,126	219,609	21
ME14	98,713	202,361	
NH1	98,937	202,820	25
NH2	99,318	203,602	26
NH3	99,760	204,509	14
NH4	105,118	215,491	19
VT1	103,779	212,746	32
VT2	101,118	207,291	22
Total: 20	**1,742,682**	**3,572,499**	**21 average**

Wood-based biofuel plant production, wood use, and woodshed diameters

Facility	Biofuel Produced (gallons/year) – assumes wood waste fully utilized	Wood Use (green tons/year)	Woodshed Diameter (miles)
Maine North	46,539,708	1,234,475	50
Maine Central	45,879,995	1,216,976	48
Maine East	48,571,474	1,288,368	60
Maine South	46,048,891	1,221,456	47
New Hampshire North	46,359,916	1,229,706	70
New Hampshire South	45,700,543	1,212,216	43
Vermont	45,795,019	1,214,722	74
Total: 7	**324,895,546**	**8,617,919**	**57 average**

The Billion Ton Study update[55] is used for wood supply estimates because it provides the most recent county-level estimates for the entire country. Nonetheless, there are important limitations and these should be treated as very optimistic estimates.

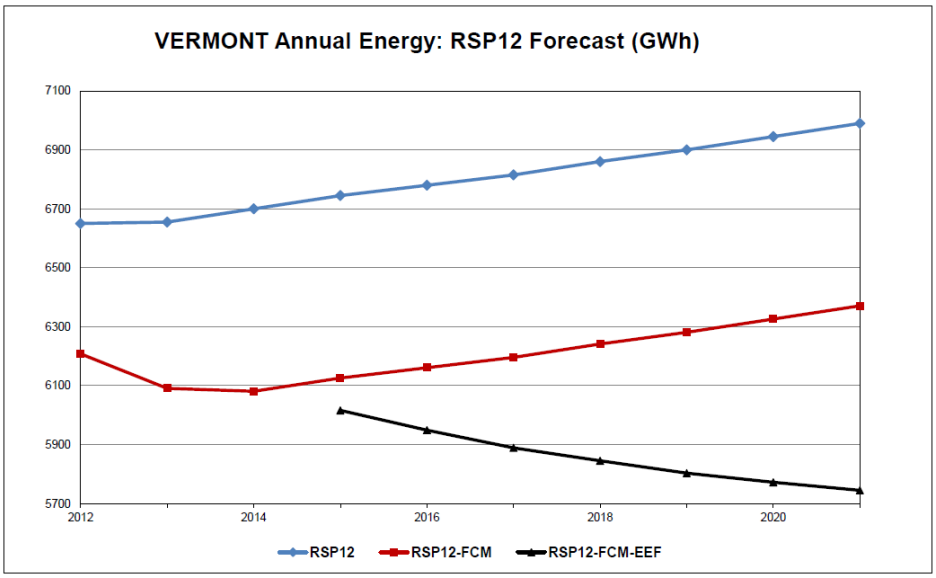
- There are no restrictions due to landowner intentions, although woodlot owner surveys indicate that most owners in this region have no intention to harvest at all – inclination to conduct whole-tree harvests for relatively low-value wood is likely to be even lower.
- Land base restrictions removed only parks and wilderness from forest eligible for harvest, with some minor limitations on quantity due to distance from road and steep terrain – and no restrictions for wetlands beyond possibly limited inventory indicated by FIA plot data. Unroaded areas are included in estimates, though cutting in these areas would occur only at higher wood prices.
- Logging residue estimates are from Timber Product Output data, which are derived from harvest volume estimates, measurements at sample harvest sites, and mill surveys. The latter two sources are considerably out-of-date for many states and likely do not reflect recent increases in

utilization of previously non-commercial tops and cull trees due to developing energy markets. Available primary mill residues are also from TPO data that are likely outdated. Because of these data limitations, the BTS update may overestimate all sources of available residues, from logging to mill.

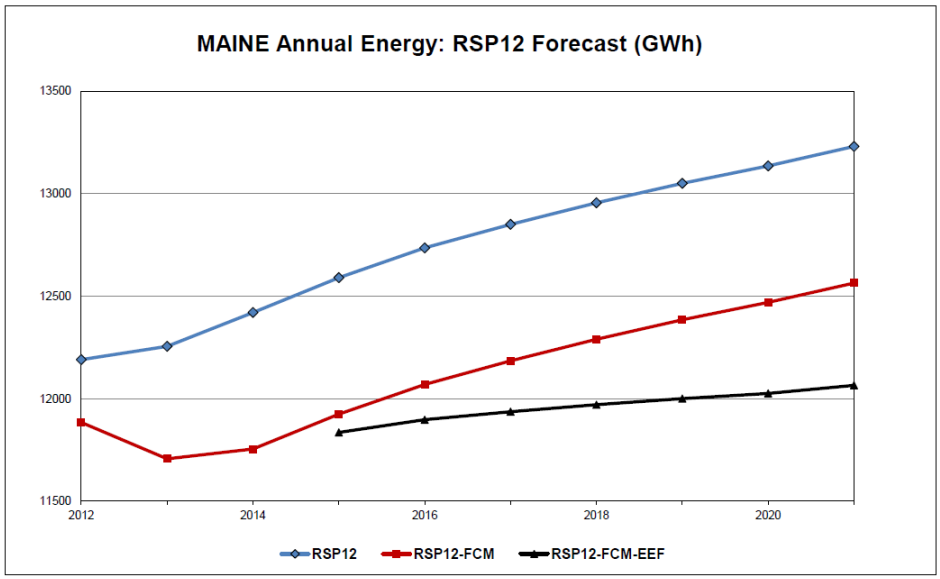
- The thinning regime for BTS integrated operations assumes that half of non-reserved forestland with density at 30% of the theoretical maximum for that forest type will be thinned (across all tree diameters down to 1") down to 30% of the maximum stand density over 30 years. (Integrated operations are described as "restoration harvests" but are not restricted to fire-prone systems with unnaturally dense stands. The future of this feedstock source after year 30 is not addressed – if these are truly "restoration" thinnings, they should not need to be repeated at frequent intervals). Since the economics of these operations depend on harvesting larger trees, integrated harvest is restricted so that pulp/sawlog material is limited to 2006 state harvest volumes (assumed to increase over time) This restriction is not limiting for Maine, but it causes New Hampshire's supply to be only 64% and Vermont's 82% of its modeled quantity for composite operations in 2012 at $100/dry ton, with the discrepancy likely much less by 2030 since processing capacity is assumed to expand over time.
- BTS does not explain the derivation of state-level estimates for secondary mill residues, and no county-level data are provided, so this source is not mapped. Construction and demolition debris and municipal solid waste are also excluded from mapping since they are not directly related to local forest capacity. We do account for secondary mill and solid waste sources by increasing wood available for each plant based on the statewide proportion of secondary waste to forest and primary mill sources.

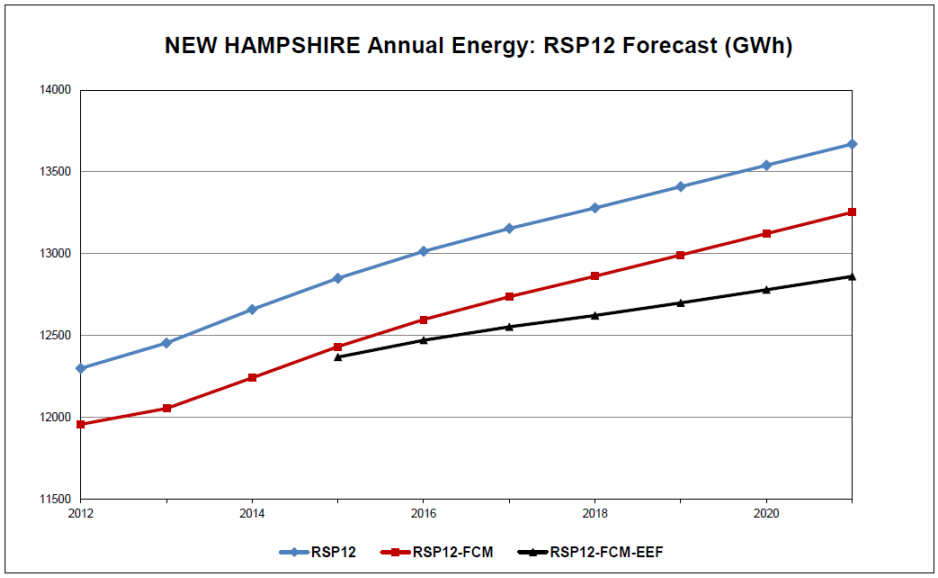
Appendix 3: Influence of Electricity Efficiency Programs on Demand – ISO-NE Modeling

ISO-New England is refining the way energy efficiency programs influence demand projections, in order to avoid investing in transmission or new capacity if cheaper solutions exist. The charts below show projections through 2021 for the three northern New England states.[4] RSP12 Forecast is a projection of by the Independent System Operator - New England (ISO-NE) of total electricity usage with no constraints on demand, as developed for the Regional System Plan issued in 2012 (RSP12). RSP12-FCM shows the effects of a forward capacity market (FCM). The FCM is designed to ensure that sufficient plans are underway today to meet future electricity needs, by offering payment up-front for promises to provide future capacity. New England's FCM accepts formal demand management arrangements as an alternative to expanding future supply. RSP12-FCM-EEF shows the additional effects of energy efficiency forecasts (EEF) resulting from programs commonly instituted in New England states, including Efficiency Vermont and Efficiency Maine. These projections are based on current programs and likely funding levels; changes in policy, pricing or consumer values could further reduce demand. Vermont's energy use is projected to fall over this period, and the others to substantially stabilize.



[4] ISO New England Staff, Energy Efficiency Forecasting Working Group. March 16, 2012. Final Energy-Efficiency Forecast, 2015-2021, accessed 1-3-13, http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/frcst/2012/iso_ne_ee_forecast_2015_2021.pdf .


MAINE Annual Energy: RSP12 Forecast (GWh)
13500
13000
12500
12000
11500
2012
2014
2016
2018
2020
RSP12
RSP12-FCM
RSP12-FCM-EEF


NEW HAMPSHIRE Annual Energy: RSP12 Forecast (GWh)
14000
13500
13000
12500
12000
11500
2012
2014
2016
2018
2020
RSP12
RSP12-FCM
RSP12-FCM-EEF

Appendix 4: Estimating GHG Emissions

Greenhouse gas emissions summarized here include those associated with manufacturing, transporting and constructing the facility. In addition, we provide estimates for emissions associated with special grid integration adjustments (emissions from increased spinning reserves – mostly natural gas generation – required to integrate highly-intermittent resources into the grid), and from wood combustion and land clearing. Since we are interested in potential GHG reductions compared to the current emissions level, we calculate both a rate of emissions per unit of energy and total emissions reductions due to an incremental increase in each source from today's level of use to the scenario amount. Unless otherwise indicated, GHG emissions of each technology are average values from two sources: 1) Weisser, Daniel. 2007. A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies. Energy 32(9): 1543-1559, http://www.iaea.org/OurWork/ST/NE/Pess/assets/GHG_manuscript_pre-print_versionDanielWeisser.pdf , accessed 12/22/10; and 2) U.S. Department of Energy, National Renewable Energy Laboratory, Life-Cycle Analysis Harmonization Project, http://en.openei.org/apps/LCA/.

Inland Wind Electricity

- Manufacturing, construction, and maintenance emit approximately 17 $^{kgCO2e}/_{MWh}$ (range 8 to 30). 12,692,003 new MWh of wind to reach the 14,048,051 MWh goal would release 215,764 $^{metric\ tons\ CO2e}/_{year}$.
- Relatively few life-cycle assessments have been performed for long-distance transmission line construction and operation, so greenhouse gas emissions associated with this component are highly uncertain. For renewables with low emissions profiles, however, they can represent a significant portion of overall emissions. An LCA study for California, based on materials used in transmission construction and SF_6 released during operation, estimated emissions at 1,735 $^{kgCO2e}/_{MWh\text{-}km}$ for 345 kV 1,000 MW transmission line, and 1,121 $^{kgCO2e}/_{MWh\text{-}km}$ for 765 kV 2,000 MW transmission line.[56] This translates to emissions of 1,078 metric tons per mile for 345 kV line (1,735 $^{kgCO2e}/_{MWh\text{-}km}$ x 1 km x 1,000 MW x 0.6212 $^{miles}/_{km}$ / 1000 $^{kg}/_{metric\ ton}$). Total emissions for 2,160 miles of new transmission for the inland wind scenario would be 2,328,480 metric tons, or 7 kg per MWh of electricity delivered over a 25 year lifetime. (We omit emissions from local connector lines, which are relatively small and similar for all scenarios).
- Greenhouse gases from land clearing along ridges, access roads, and transmission lines take two forms: rapid losses due to converting standing forest to mulch and perhaps some wood products, and annual loss of future sequestration capacity. Forests above 2,000 feet elevation in northern New England have average above-ground forest carbon stocks of 141 metric tons CO_2e per acre, with average across all elevations at 126 metric tons.[57] Intact forests absorb about 2 metric tons CO_2e per acre per year, so loss of potential sequestration over 25 years of project life amounts to 50 more $^{tons}/_{acre}$. Clearing for turbines (4,955 acres), crane paths (1,990 acres) and access roads (230 acres) would be mostly at high elevation, while clearing for transmission lines (43,158 acres) would occur across all elevations. Carbon losses from clearing for wind facilities plus associated transmission would total about 358,649 $^{metric\ tons\ CO2e}/_{year}$ ([(7,175 acres x 191 $^{metric\ tons\ CO2e}/_{acre}$) + (43,158 acres x 176 $^{metric\ tons\ CO2e}/_{acre}$)] ÷ 25 years).

- Additional spinning reserves, plus lower efficiency for balancing sources (most likely natural gas plants) ramping up and down more frequently, result in additional emissions due to grid integration. Effects are incompletely understood, but they generally depend on wind variability, predictability, and correlation with load, the flexibility of generating sources already on the grid, and the potential for demand-response tools to help load track supply rather than vice versa. The New England Wind Integration Study (NEWIS)[58] estimates that spinning reserves would increase by about 3% of the nameplate capacity of wind (310 MW for 9,800 MW of wind) for New England as a whole. With a capacity factor of 30%, additional spinning natural gas would be about 11% of the wind power generated, which under our 25% scenario would emit 703,645 $^{\text{metric tons CO2e}}/_{\text{year}}$, or 2.5 times the emissions from manufacturing and construction.
- Total emissions from wind plus natural gas backup would be 1,284,843 $^{\text{metric tons CO2e}}/_{\text{year}}$.

Offshore Wind

- GHG emissions from manufacturing, construction, and maintenance of offshore turbines releases about 9-19 $^{\text{kgCO2e}}/_{\text{MWh}}$.[59] This scenario produces 182,625 metric tons CO_2e (14,048,051 MWh x 13 $^{\text{kg}}/_{\text{MWh}}$ ÷ 1,000 $^{\text{kg}}/_{\text{metric ton}}$) of new emissions from this source each year.
- Construction of 715 miles of new high-voltage lines would emit about 770,770 (1,078 metric tons/ mile x 715 miles), or 2 kg per MWh of electricity delivered over a 25 year lifetime.
- Emissions from land clearing would result only from transmission under this scenario. Clearing 13,000 acres for transmission lines would emit about 91,520 $^{\text{metric tons}}/_{\text{year}}$ (13,000 acres x 176 $^{\text{metric tons CO2e}}/_{\text{acre}}$) ÷ 25 years).
- As for onshore wind, additional spinning reserves plus lower efficiency for balancing sources ramping up and down require additional natural gas combustion, assumed at 9% of wind production (slightly lower than onshore due to less variable winds). 14,048,051 MWh x 0.09 x 504 $^{\text{kgCO2e}}/_{\text{MWh}}$ = 637,220 $^{\text{metric tons CO2e}}/_{\text{year}}$.
- Total emissions would be 913,670 $^{\text{metric tons CO2e}}/_{\text{year}}$ for offshore wind plus natural gas backup.

Woody Biomass Electricity

- GHG emissions from manufacturing, construction, and maintenance release 35-99 $^{\text{kgCO2e}}/_{\text{MWh}}$, so 8,418,127 new MWh of wood-fired electricity would emit about 496,670 $^{\text{metric tons CO2e}}/_{\text{year}}$.
- Construction and operation of connecting transmission would add minor amounts of new emissions.
- Assuming only half of new plants require site clearing, and including forest access roads and new transmission, land clearing would emit about 69,105 $^{\text{metric tons CO2e}}/_{\text{year}}$ ((9,816 acres x 176 $^{\text{metric tons CO2e}}/_{\text{acre}}$) ÷ 25 years).
- Additional GHGs from biomass combustion to produce incremental biomass electricity would total 12,315,720 $^{\text{metric tons CO2e}}/_{\text{year}}$ (1,463 $^{\text{kgCO2e}}/_{\text{MWh}}$ [60] x 8,418,127 MWh).
- Depending on the net climate impacts assumed for wood combustion emissions, total GHG emissions range from 565,964 to 13,477,648 $^{\text{metric tons CO2e}}/_{\text{year}}$. Assuming this source displaces all coal and oil capacity in these states plus 5 million MWh from Vermont Yankee, emissions displaced would be only 3,405,130, and wood use could actually more than triple the current level of emissions. The actual net effect depends on the source of wood and the fuel replaced. Most waste wood and tops from existing harvest would release their carbon relatively quickly if not burned for

energy, so emissions from these materials are merely accelerated by 10 to 30 years rather than representing totally new sources. Even emissions from newly-cut roundwood may be offset over time, *if* source forests are maintained in forest cover and well-managed so as to grow more quickly than unthinned forests, though the delay results in some warming effect. Accounting for reabsorption of carbon by forests, cumulative emissions from wood electricity remain about 124% higher than those from natural gas by 2050, but only 10% higher than those from coal.[61]

Regional Hydroelectricity

- GHG emissions from manufacturing, construction, and maintenance for hydroelectricity range from 1-34 $^{kgCO2e}/_{MWh}$, or 70,581 $^{metric\ tons\ CO2e}/_{year}$.
- Connecting transmission construction would add minor amounts of new emissions.
- Clearing for roads and penstocks would release greenhouse gases at about 8,019 metric tons CO_2e/year (1,139 acres x 176 $^{metric\ tons}/_{acre}$ ÷ 25 years). The new run-of-river generating facilities assumed in our scenario do not involve new impoundments, so there are no additional emissions from reservoir land clearing or outgassing.
- No additional spinning reserves are required since hydro is dispatchable on an hourly basis, despite seasonal capacity factor limits due to limited water supply.
- Total emissions from 4,033,207 MWh of new hydro generation to meet the 23% scenario are about 80,905 $^{metric\ tons\ CO2e}/_{year}$.

Canadian Hydroelectricity

- It is sometimes argued that no new net emissions would be incurred by purchasing electricity from existing hydroelectric facilities in Canada. However, incremental expansion in purchasing would presumably require added capacity, and we assume that new facilities will cause emissions at a similar rate per MWh generated (Figure 12) as those from existing operations. As for all scenarios, Table 11 applies this rate to only the incremental increase in electricity from this source.
- Manufacturing, construction, and maintenance emit 1-34 $^{kgCO2e}/_{MWh}$, with those from HQ probably toward the high end compared to the smaller regional hydro facilities. 8,052,051 $^{MWh}/_{year}$ of additional use would generate 161,041 $^{metric\ tons\ CO2e}/_{year}$ (8,052,051 MWh x 20 $^{kgCO2e}/_{MWh}$ ÷ 1000 $^{kg}/_{metric\ ton}$).
- We assume that new long-distance transmission larger than under the wind scenario at 765 kV and 2000 MW (see transmission notes under wind scenarios above). Emissions from construction and operation would be 1,393 metric tons per mile (1121 kg $^{kgCO2e}/_{MWh\text{-}km}$ x 1 km x 2,000 MW x 0.6212 $^{miles}/_{km}$ ÷ 1000 $^{kg}/_{metric\ ton}$). Total emissions from 360 miles of new line would be 501,480 metric tons, or 2.5 $^{kg}/_{MWh}$ of electricity delivered over 25 year line lifetime.
- Reservoir outgassing and carbon losses from cleared vegetation could be about 176 $^{kgCO2e}/_{MWh}$ for lands flooded within the past few decades. These emissions decline over time as reservoirs mature, so we include half this rate in the total, or 708,581 metric tons.[62] Emissions from clearing for transmission lines would total about 59,183 metric tons (7% of 26,596 acres for existing high-voltage transmission plus 6,545 acres of new transmission, divided by 25 year lifetime).
- Total emissions from 8,052,051 MWh of new HQ power would be about 961,578 $^{metric\ tons\ CO2e}/_{year}$.

Solar Photovoltaics

- Emissions from manufacturing and installation total 43-73 $^{kgCO2e}/_{MWh}$, for a total of 772,642 metric tons CO_2e (14,048,031 MWh x 55 $^{kg}/_{MWh}$ / 1,000 $^{kg}/_{metric\ ton}$).
- Since no land is cleared for solar farms, and location near load avoids new transmission investments, there are no associated emissions.
- As for wind, if solar PV reaches significant penetration there may be some emissions associated with balancing resources. On partly cloudy days, output from solar PV panels may ramp up and down by 50% within 30-90 seconds or 70% within 5-10 minutes.[63] Multiple installations are unlikely to be synchronized, however, so variability will decrease with diversity of locations. Solar is also better correlated with load, so integration effects should be considerably lower than those for wind. Data on integration needs for solar PV are scarce, but one study for southern Nevada estimates additional natural gas regulation needs for 21% large-scale and distributed solar at 4% of solar generation.[64] This would add about 283,208 $^{metric\ tons\ CO2e}/_{year}$ of natural gas emissions to the solar scenario.

Reduced Demand for Electricity

- Demand reduction reduces greenhouse gases more effectively than substituting new renewable sources, which all emit greenhouse gases at some level. Some tools, such as smart meters and energy efficient appliances, may release greenhouse gases during manufacture and transport. The process of discarding inefficient motors and appliances, and manufacturing and shipping new ones, will also generate greenhouse gases. Assuming that these effects are minor, there would be essentially no GHG emissions associated with this scenario.

Ground-Source Heat Pumps

- Emissions depend upon electricity sources, so these impacts would be reflected in the electricity sector. If 2050 electricity retained the 2010 emissions profile, this option would emit 2,380,019 metric tons CO_2e from electricity to run heat pumps. This assumes heat pumps generate 4 times as much heat energy as they require in electrical energy. 91.5 trillion Btu heat would require 22,875,000 MMBtu ÷ 3,412 $^{MMBtu}/_{GWh}$ = 6704 GWh x 355 $^{metric\ tons}/_{GWh}$ for current electricity mix). A shift toward non-fossil electricity sources would further reduce emissions. The area disturbed for horizontal systems would likely already be cleared, so we assume no emissions from land clearing.

Wood Heat

- Bringing wood heat up to 25% of the total would require 61.8 trillion Btu of additional wood heat (which requires 77.3 trillion Btu of wood at 73% conversion efficiency). Analysis for the Northeast/MidAtlantic Low Carbon Fuel Standard estimated indirect pellet emissions at 11 to 18 g/MJ (average 15 $^{kg}/_{MMBtu}$), so indirect emissions from pellets would be about 565,905 metric tons CO_2e (61,847,564 MMBtu x 0.61 portion of heat x 15 $^{kg}/_{MMBtu}$ ÷ 1,000 $^{kg}/_{metric\ ton}$). Indirect emissions from firewood and chips are much lower at about 2-4 $^{kg}/_{MMBtu}$ of combustion emissions, about 72,362 metric tons CO_2e (61,847,564 MMBtu x 0.39 portion of heat x 3 $^{kg}/_{MMBtu}$ ÷ 1,000 $^{kg}/_{metric\ ton}$), so total indirect CO_2e emissions from wood heat would be 638,267 metric tons CO_2e, similar to indirect oil emissions of 605,238 metric tons.

- Assuming half of new plants require site clearing, and including new forest access roads, land clearing would emit about 58,214 $^{\text{metric tons CO2e}}/_{\text{year}}$ ((8,269 acres x 176 $^{\text{metric tons CO2e}}/_{\text{acre}}$) ÷ 25 years).
- Direct GHG emissions from wood combustion are approximately 105 $^{\text{kg}}/_{\text{MMBtu}}$, or about 8,895,882 $^{\text{metric tons CO2e}}/_{\text{year}}$. The ultimate atmospheric impact of this burst of new wood emissions depends upon whether they would have occurred fairly soon anyway if not used for energy, and whether source forests rapidly reabsorb the carbon emitted through combustion. According to Manomet modeling under Massachusetts conditions, replacing oil with wood heat results in a cumulative reduction in net direct+indirect emissions of about 20% by 2050, a bit less using pellets due to higher indirect emissions.[65] On this basis, expanded wood heat reduces overall 2050 GHGs by about 1,183,900 metric tons CO_2e.

Reduced Demand for Heat

- According to a Vermont study, achievable cost-effective demand reduction for heating and process energy over 10 years can reduce GHG emissions by 0.067 $^{\text{metric tons CO2e}}/_{\text{MMBtu}}$ saved.[66] (Wood energy savings are not considered to generate emissions reductions since wood combustion is assumed carbon neutral. This result underlines the absurdity of the carbon neutrality assumption, since clearly burning less wood will reduce CO_2 emissions to some extent). If efficiency measures target households currently using oil heat, total reductions for this scenario would be about 6,137,200 metric tons CO_2e (91,600,000 MMBtu reduction x 0.067). Our emissions reduction figure assumes that oil heat is targeted first, so it reflects a full reduction in oil heat emissions.

Electric Vehicles

- Electric vehicle emissions depend on how the electricity is generated, so these effects are captured in the expanded electricity sector. If electricity sources stayed the same as the 2010 mix, this option would emit about 5,205,696 metric tons CO_2e associated with the electricity used (150,100,000 MMBtu ÷ 3 (reflects improved vehicle efficiency) ÷ 3,412 $^{\text{MMBtu}}/_{\text{GWh}}$ x 355 $^{\text{metric tons}}/_{\text{GWh}}$). If electricity sources shift toward fewer fossil fuels, emissions from this scenario would be lower. These emissions do not include those from energy embedded in vehicles and fueling/charging equipment.

Wood-Based Biofuels

- Analysis for a proposed Northeast/Mid-Atlantic Clean Fuels Standard reported the following life-cycle emissions rates for fuels from forestry residue: ethanol from fermentation -4.4 $^{\text{g}}/_{\text{MJ}}$ (-5 $^{\text{kg}}/_{\text{MMBtu}}$) and ethanol from gasification +9.9 $^{\text{g}}/_{\text{MJ}}$ (+10 $^{\text{kg}}/_{\text{MMBtu}}$), or about 97,821 metric tons CO_2e per year (39,128,236 MMBtu x 2.5 $^{\text{kg}}/_{\text{MMBtu}}$ ÷ 1,000 $^{\text{kg}}/_{\text{metric ton}}$). (Negative values reflect the fossil-displacement benefits of electricity produced along with the biofuels.) These emissions estimates may not fully reflect the long distances that wood needs to be transported to fuel such large facilities.
- Assuming half of new plants require site clearing, and including new forest access roads, land clearing would emit about 57,950 $^{\text{metric tons CO2e}}/_{\text{year}}$ ((8,231 acres x 176 $^{\text{metric tons CO2e}}/_{\text{acre}}$) ÷ 25 years).
- These values exclude direct emissions from combustion of wood and its byproducts. Assuming complete combustion at some point along the processing chain, a given mass of wood should emit the same amount of GHGs – though proportion of methane may vary. It takes approximately 2.3

Btu of wood to make 1 Btu of biofuel, and applying the standard wood combustion emissions factor to the total wood combusted during manufacturing and in final use yields direct emissions of 9,337,420 metric tons (39,128,236 MMBtu x 2.27 x 105 $^{kg}/_{MMBtu}$ ÷ 1,000 $^{kg}/_{metric\ ton}$). Emissions from the equivalent amount of gasoline and diesel would be about 3,342,803 metric tons CO_2e (85 and 87 $^{kg}/_{MMBtu}$ for gasoline and diesel).[67]

- As for electricity and heat, forest carbon absorption mitigates short-term emissions over time. Since the Manomet report did not model liquid fuels, we use a source from Finland that directly compares life-cycle global warming impacts from fossil and wood-based transportation fuels over time, including adjusting for changes in forest carbon (since forest conditions in Finland and New England differ considerably, this should be taken as a rough approximation only).[68] At 40 years after the start of production, diesel from forest residues reduces climate impacts by about 10% compared to fossil diesel. Applying this same relative reduction to ethanol and roundwood feedstocks likely exaggerates biofuel benefits, though the biofuel advantage increases in years after 2050. Using these figures, net biofuel GHG emissions might be about 3,008,523 $^{metric\ tons\ CO2e}/_{year}$, a reduction of 334,280 metric tons compared to gasoline and diesel.

Reduced Demand for Transportation

- Reducing transportation fuel use by 75.2 trillion Btu will reduce emissions by 6,428,468 $^{metric\ tons\ CO2e}/_{year}$.

Appendix 5: Estimating Financial Costs

Levelized costs for construction and operation are taken from the 2012 Annual Energy Outlook produced by the US Department of Energy, Energy Information Administration, including regional adjustments.

Inland Wind

Average national inland wind costs projected for 2017 are $0.097/kWh in 2010 dollars (omits the effect of federal tax credits since this is also a cost to society).[69]. Adjusting this national estimate for the 5% cost differential for Vermont, New Hampshire and Maine yields a regional cost of $0.102/kWh, though wind cost surveys by the National Renewable Energy Laboratory find northeast differentials as high as 20%[70]. This includes the cost of local transmission connection, but does not include the cost of major long distance transmission upgrades nor the effects of curtailment at high penetration levels. At about $11 billion for high-voltage lines, amortized over 25 years, transmission costs would add another $0.03/kWh to wind power costs. There will be additional costs associated with more spinning reserves and frequent ramping up and down of balancing resources, with higher prices needed to induce natural gas plants to play that role. 2010 wind projects cost 65% more per installed kW than those built from 2001 to 2004 (installed cost is a better indicator than wind power price, since the price is artificially suppressed by public subsidies), but costs declined in 2011. Operations and maintenance costs generally increase as plants age, but recently constructed facilities seem to have lower operating costs at the same plant age compared with wind farms installed in earlier years.[71]

Offshore Wind

Total levelized costs for offshore wind for 2017 are projected at $0.22/kWh in 2010 $ (omits effect of federal tax credits since this is also a cost to society).[72] The DOE estimates are based on fixed foundation turbines. DeepC Wind's goal is to produce power at $0.10/kWh by 2020, exclusive of transmission (the floating design lowers cost by building and maintaining in port and towing to sea).[73] 1 GW projects, unless connected at existing high-capacity sites such as the former location of Maine Yankee, would require considerable transmission investments. Connecting transmission is included in DOE cost estimates, though long-distance transmission upgrades are not. 705 additional miles of high-voltage transmission would add about $0.01/kWh to offshore wind electricity costs.

Woody Biomass Electricity

U.S. DOE projects levelized costs of biomass electricity in 2017 at $0.11/kWh in 2010 $ (omits effect of federal tax credits since this is also a cost to society).[74] Since fuel costs are a significant factor, costs will vary regionally, and this figure reflects costs for Vermont, New Hampshire and Maine at about 5% below the national average.

Regional Hydroelectricity

National projected 2017 costs for hydroelectricity are $0.09/kWh in 2010 $ (omits effect of federal tax credits since this is also a cost to society).[75] Since this national average is based on a very large conventional dam, we adjust the estimate upward to $0.13 to reflect higher regional costs and micro-hydro designs. A recent Vermont study found costs for hydropower (project development and

construction only) at several existing dams in New England ranging from about $0.11 to $.13/kWh.[76] We assume that micro-hydro installations would have a similar cost.

Canadian Hydroelectricity

The current Vermont contract with Hydro Quebec starts at a price of $0.058 per kWh in 2012, and adjusts up and down with the market at a limited rate. HQ also sells energy on the region's spot market, and charges a 10% premium for responding to emergency needs. Since the major positive role for this power in the future could be to help balance intermittent renewables, we've applied that price premium to the estimated cost. The other scenarios use 2017 cost projections, but low natural gas prices are expected to keep electricity prices from climbing so we assume 2017 prices will be similar to 2012. $2.2 billion for two new high-voltage power lines with a 25 year lifetime would add $0.006/kWh ($2,200,000,000 ÷ (25 x 14,048,051,000 kWh)), bringing the price to $0.07/kWh.

Solar Photovoltaics

$0.19/kWh in 2010 $ projected for 2017 (omits effect of federal tax credits since this is also a cost to society).[77] Because the EIA assumes very large centralized utility-scale solar farms, while our scenario calls for small distributed facilities, we omit the transmission portion of EIA's levelized cost for solar. Note that the cost of solar panels has been dropping dramatically in recent years with increased volume manufactured in China, though tariffs and dumping penalties may remove that cost advantage. Between 1998 and 2010, total installed costs of PV systems in the U.S. dropped 43% in real terms, from $11/kW to $6.20/kW (2010 dollars). U.S. prices remain considerably higher than those in countries with more established demand, indicating the potential for further cost savings.[78] If these trends continue, the price/kWh for solar is likely to become competitive with other sources during the next decade. As for wind, grid integration will require some additional reserves to stabilize the system, which raises overall costs at high levels of penetration. A widely distributed system has pluses and minuses – diverse locations will dampen variations in total output, but managing thousands of small grid-tied systems will be more difficult than regulating a few key sources.

Reduced Demand for Electricity

Recent demand-reduction measures financed by Efficiency Vermont and Efficiency Maine have cost about $0.03 to $0.04/kWh to-date and Vermont, New Hampshire and Maine could achieve 19-21% reductions in electricity demand by 2018 through additional cost-effective measures.[79] ISO-NE energy efficiency modeling predicts that the costs of demand reduction will rise over time to $0.044 (NH), $0.0485 (ME) and $0.0580 (VT) by 2021 – with Vermont's cost highest due to its higher past investment and hence saturation of the less expensive options.[80] A New Hampshire study predicts that marginal costs per kWh increase abruptly to over $0.20/kWh for conservation measures beyond a 20% demand reduction.[81] Behavioral changes that lower energy demand may save rather than cost money, but may have nonfinancial costs in terms of comfort or convenience.

Ground-Source Heat Pumps

A ground-source heat pump installation for one home using 100 MMBtu of heat annually costs about $30,000, plus electricity costs for about 25% of the total heat energy used. Assuming equipment lifetime of 25 years, heat would cost approximately $11/MMBtu for capital costs and $11/MMBtu for

operating, or $0.08/kWh-equivalent. This is lower than the cost of oil heating oil heating at $35/MMBtu ($3.60/gallon at 83% efficiency plus $8,000 capital cost over 20 years).

Wood Heat

The majority of wood heat costs are for equipment – pellet boilers and furnaces generally cost about $15,000 (about $7 per MMBtu over equipment life) compared to $3,000 for a woodstove (about $1/MMBtu), $8,000 for oil or $5,000 for propane (about $2-3 per MMBtu).[82] Annual wood fuel costs will generally be lower than fossil fuel costs, and the savings will likely increase over time as fossil energy costs rise. Firewood at $200 a cord costs $9.50/MMBtu, pellets at $250/ton cost about $18/MMBtu and oil at $3.60/gallon costs about $31/MMBtu. In kWh equivalents the cost of wood heat would be $0.08 and $0.04/kWh. With equipment costs spread over 20 years plus fuel costs, firewood saves about $22/MMBtu and pellets $9/MMBtu compared to the cost of oil.

Reduced Demand for Heat

The financial costs of reducing demand for space heat or process energy are largely from renovation of existing buildings, equipment replacement, and improved energy performance for new buildings and equipment. An efficiency study for Vermont estimates that non-electricity efficiency programs can achieve savings of 25.6 trillion Btu at a cost of $241 million in private and public investment over 10 years, or $9.41 per MMBtu. Since the lifetimes vary for the various investments involved, it is difficult to compare costs directly to those for new energy supply. However, converting to electricity equivalents at 1 MMBtu = 293 kWh, the cost of demand reduction for heat is about $0.032 per kWh, very similar to the cost of electricity demand reduction and much less than new supply.

As for electricity savings, costs rise rapidly once reductions reach a certain threshold. In Vermont, this threshold occurs for residential heat at about 22% savings and $30/MMBtu for oil, at 16% savings and $45/MMBtu for propane, and at 45% savings and $15/MMBtu for wood (reflecting the number of inefficient wood stoves in circulation). Corresponding break points are higher for the commercial sector (35% oil, 30% propane) and no supply curves were provided for the industrial sector.[83]

Electric Vehicles

Economic studies for the proposed Northeast/MidAtlantic Clean Fuel Standard estimated the costs of converting to electric vehicles over 10 years. The infrastructure cost (including home and commercial vehicle chargers and grid upgrades) averaged across all scenarios was $.046/kWh. Electric vehicles may cost up to $5,000 more than conventional, so a car using 5,000 kWh/year with a 10-year vehicle life could add another $0.10/kWh.84 Some conversion costs are one-time, and others will decline with market penetration for electric vehicles so costs should decline over time (for this limited modeling over just 10 years maximum fleet conversion for any scenario was 21%). Cost in kWh equivalents would be $0.146.

Wood-Based Biofuels

Economic analysis for the NE/MA Clean Fuel Standard predicts that the costs per gallon of cellulosic ethanol and biodiesel (on a gasoline-gallon-equivalent basis that accounts for lower energy content of biofuels) will be about the same or lower than the cost of gasoline or diesel through 2022. Costs of

converting to biofuels would include capital costs for the refineries, duplicate tanks for gas stations, and the cost of converting vehicles to burn higher mixes or pure biofuels. These costs, per MMBtu of biofuels used, average $17/MMBtu, or $0.06/kWh equivalent, across all scenarios.

Reduced Demand for Transportation

Conventional vehicles with higher mpg may require higher capital costs. Reducing miles traveled, on the other hand, will save money compared to the status quo – though it may come at the cost of some personal convenience or time. Since this option perhaps more than any other relies on behavioral changes and consumer choices rather than investments in new equipment, it is difficult to estimate net costs or savings.

End Notes with Citations

[1] It is also consistent with ISO-NE modeling of wind integration at 20-24% of New England's electricity. Some in-region energy resources (hydroelectricity and woody biomass for electricity and liquid fuels) are not sufficient to reach 25%, so those scenarios fall slightly below that target.

[2] Utility regulators and planners tend to consider only emissions externalities, a hold-over from the days when generation was dominated by combustion. See, for example, the discussion of externalities in Hornby, Rick, Chernick, Paul, Swanson, Carl, White, David, Gifford, Jason, Chang, Max, Hughes, Nicole, Wittenstein, Matthew, Wilson, Rachel and Biewald, Bruce. July 21, 2011 amended August 11, 2011. Avoided Energy Supply Costs in New England: 2011 Report. Synapse Energy Economics, Inc. pp. 6-89 to 6-101. Since renewable technologies generate new types of externalities, regulatory processes and policy's favoring particular alternatives will need to expand the range of environmental effects considered.

[3] Globally, one estimate placed the global value of ecosystem services at about $33 trillion compared to global gross national product of $18 trillion (Constanza, R. Robert Costanza, Ralph d'Arge, Rudolf de Groot, Stephen Farberk, Monica Grasso, Bruce Hannon, Karin Limburg, Shahid Naeem**, Robert V. O'Neill, Jose Paruelo, Robert G. Raskin, Paul Sutton & Marjan van den Belt. 1997. The value of the world's ecosystem services and natural capital. Nature 387:253-360). A similar analysis estimated the value of ecosystem services in Maine at $14.7 billion – compared to gross state product of $51.6 billion – but this estimate excluded "existence values" which do not depend on direct human uses (Troy, Austin. April, 2012. Valuing Maine's Natural Capital. Spatial Informatics Group, LLC for Manomet Center for Conservation Sciences, http://www.manomet.org/sites/manomet.org/files/reports/Troy_2012_Value_of_Maine.pdf) .

[4] Hooper, D.U., Adair, E.C., Cardinale, B.J., Byrnes, J.E.K., Hungate, B.A., Matulich, K.L., Gonzalez, A., Duffy, J. E., Gamfeldt, L., and O'Connor. M.I. 2012. A global synthesis reveals biodiversity loss as a major driver of ecosystem change**.** Nature*,* DOI: 10.1038/nature11118

[5] This is total primary energy used to generate the electricity, not the actual electrical energy used, which is only 94 trillion Btu or 27,483 GWh in 2009 (EIA SEDS Table C5-C7). Electricity is extremely inefficient at energy conversion and distribution (about 32% of primary energy). Motor vehicle engines may be only about 14-26% efficient (http://www.fueleconomy.gov/feg/atv.shtml) – which makes overall efficiency very to electric generation efficiency, while heat is typically about 60-90% efficient. Since the electricity system losses occur largely prior to the point of sale to the end user, while the transport and thermal losses occur after sale, it can be confusing to compare energy use across these sectors.

[6] US Department of Energy, Energy Information Administration. Annual Energy Outlook 2012 Early Release. The ISO New England Regional System Plan for 2012 projects similar rates of increase from 2012 to 2022 for electricity: 0.6% for Vermont, 1.2% for New Hampshire, and 0.9% for Maine (ISO-NE Regional System Plan 2012. Table 3-1, p. 30, Summary of Annual Electric Energy Use and Peak Demand for New England and the States, www.iso-ne.com/trans/rsp/2012/rsp_Final_110212.docx.)

[7] Total energy used to generate electricity grows less than use – at 0.65% annually) because of lower losses (68% in 2010 down to 66% in 2035).

[8] This rate of increase in transportation energy does not account for recently-revised fuel economy standards for light duty vehicles 2017 and later. This rule is estimated to result in transportation emissions that are 10% lower by 2035 compared to the reference case without the new CAFÉ standards (EIA Annual Energy Outlook 2012, p. 31). Our transportation demand reduction scenario might include improved fuel efficiency standards as part of the overall 25% reduction in transportation energy use, even in the face of growing population and vehicle numbers.

[9] Rate of increase for nonelectric assumes that use by sector grows at the same rate nationally and as for nonelectric portion of total at the state level (0.1% residential, 0.68% commercial, 0.57% industrial). Growth rate is applied separately to each state based on nonelectric for each sector, and weighted average annual rate of increase is calculated.

[10] These are ambitious but feasible goals for 2050. Electric vehicles are about 60-80% efficient since they generate little waste heat - Energy Economy Ratio of 3.0, from CAR – Andress et al. 2011) and ground source heat pumps are about 200-300% efficient since they tap "free" ground heat. So converting these uses to electricity actually reduces "otherwise" energy use, though to the extent low-conversion fossil electricity is still used this advantage disappears in the energy losses where electricity is made plus line losses.

[11] Conversion assumes electric cars are 3 times more efficient than gasoline/diesel and heat pumps generate 4 times the heat energy they use as electricity. These efficiencies may be a slight stretch with today's technology, but should be feasible by 2050.

[12] Multiply by 0.32 for current conversion efficiency and convert trillion Btu to GWh by multiplying by 293.

[13] Moore, James. 2009. Repowering Vermont: Replacing Vermont Yankee for a Clean Energy Future. Vermont Public Interest Research Group. GE Energy Applications and Systems Engineering, EnerNex Corporation, AWS Truepower. December 5, 2010. New England Wind Integration Study.

[14] AWS Truepower resource mapping includes all developable land with capacity factor 30% or greater, and does not account for feasible locations with concentrated potential as the EWITS and NEWIS sites do, nor for environmental or social impacts. We assume a 30% capacity factor rather than the one indicated for each site based on actual wind farm performance in the northeast to-date, and to reflect the likelihood that capacity factors will be limited at high penetration levels due to grid integration challenges. EWITS and NEWIS theoretically identify feasible locations, and minimally address environmental and social impacts by eliminating parks and wilderness, very steep sites, wetlands, and NEWIS also filters out sites near the AT.

[15] Since wind in this region is most abundant in winter and at night, meeting 25% of the region's *summer peak* load would require much greater installed capacity at about 15,868 MW. In order for wind to meet 25% of hourly *peak* use, we need to account for the hourly peak being 88% higher than average annual use (based on the one-hour summer peak in 2011 as a percent of average annual capacity used – GWh divided by hours in the year). Wind also has a lower capacity factor during the summer – from 30% average down to 19%. This discrepancy between average and peak needs is smaller for other renewables. Biomass is generally dispatchable on demand, hydro has a smaller difference in capacity factor from summer to winter, and solar's seasonal capacity factor is better correlated with seasonal demand.

[16] 11,596 MW of offshore wind capacity would be needed to generate 25% of summer one-hour peak load. The increased capacity for hourly peak versus average load is less than for on-shore wind due to higher offshore summer capacity factors.

[17] Capacity factors for New England hydro - 44.9% winter, 41.1% summer, 43.3% annual - from U.S. EPA. August, 2010. Documentation for EPA Base Case v.4.10 - Using the Integrated Planning Model, Table 3-8 p. 3-13, http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html. These capacity factors are higher than those assumed by ISO-NE for New England hydro (25%). It would require about 4,200 MW of hydro capacity to generate 25% of summer one-hour peak load. Despite lower summer capacity due to reduce water flow, hydro can be scheduled to meet daily peaks even during those summer months, so the excess capacity needed for summer peaking is less than for wind, or even solar. Only the seasonal, not the daily, peaks are a factor.

[18] 15,074 MW of panels would be needed to meet 25% of one-hour summer peak load. As for the wind calculations, peak one-hour load in summer is about 1.88 times annual average load, but solar summer capacity is about 1.48 times higher than winter, so peak capacity for this technology would need to be about 1.27 times average as opposed to wind at 3 times average.

[19] New sites were those identified by an eastern wind integration study, and were chosen in order by capacity factor (EnerNex Corporation. February 2011 (revised). Eastern Wind Integration and Transmission Study (EWITS). Prepared for National Renewable Energy Laboratory. Sites with latitude and longitude - http://www.nrel.gov/wind/integrationdatasets/eastern/methodology.html). EWITS used AWS Truepower wind potential maps to identify potential commercial sites with 100-1,435MW of capacity, excluding areas of open water, wetlands, parks, steep slope, non-public federal lands (sic?), CBI GAP categories, 1, 2, 7 and 8, airports and developed areas with buffer zones. A second study conducted for ISO-NE focused more narrowly on wind integration in New England (GE Energy Applications and Systems Engineering, EnerNex Corporation, AWS Truepower. December 5, 2010. New England Wind Integration Study (NEWIS)). NEWIS developed a New England Wind Resource Area Model (NEWRAM) from the larger 3,000MW of candidate sites from EWITS rather than the final 580GW set in order to filter by regional priorities rather than east-wide ones (included sites at class 3 or higher wind speed and eliminated sites above 3,000 feet or near AT or Long Trail). 164 more candidate onshore sites were identified in New England (including 107 more in Maine to total 149, 5 more in NH to total 26, and 18 more in VT to total 35). These added sites increased available inland wind from 14.4 GW to 35.6 GW (added 13,624 MW in ME, 585 MW in NH, 2,135 MW in VT but many sites were also excluded due to proximity to long-distance trails). Geographic locations in NEWRAM are not publicly available, so this paper uses EWITS sites.

[20] To meet hourly summer peak capacity targets at 25% would require 87 additional sites with 10,501 MW of total capacity (shown in yellow on the map below). Impacts for this peaking scenario would generally be about 3 times those for the 25% average power scenario but have not been described in detail in this section. Due to its intermittent nature, wind is unlikely to serve as a peaking resource.

[21] Publicover, David A., Kimball, Kenneth D. and Poppenwimer, Catherine J. 2011. Ridgeline Windpower Development in Maine Appalachian Mountain Club Technical Report 11-1, pp. 21 and 23 and Map 4.

[22] Average direct impact area for all projects surveyed by NREL was 1.0 acres; average for single-string projects was 1.34 acres. Denholm, Paul, Hand, Maureen, Jackson, Maddalena, and Ong, Sean. 2009. Land-Use Requirements of Modern Wind Power Plants in the United States. Technical Report NREL/TP-6A2-45834. Table 1, p. 10 and Table 6, p. 22.

[23] As for inland wind, meeting 25% of peak needs from offshore wind would require considerably more capacity at about 11,596MW, but wind is unlikely to meet peaking needs.

[24] University of Maine and James E. Sewall. December 2011. Maine Deepwater Offshore Wind Report.

[25] U.S. Department of Energy. 2011. *U.S. Billion-Ton Update*: *Biomass Supply for a Bioenergy and Bioproducts Industry*. R.D. Perlack and B.J. Stokes (Leads), ORNL/TM-2011/224. Oak Ridge National Laboratory, Oak Ridge, TN. 227pp. This source is used because it provides the most recent county-level estimates for the entire country. Nonetheless, there are important limitations

and these should be treated as very optimistic estimates. There are no restrictions due to landowner intentions, although woodlot owner surveys indicate that most owners in this region have no intention to harvest at all – inclination to conduct whole-tree harvests for relatively low-value wood is likely to be even lower. Land base restrictions removed only parks and wilderness from forest eligible for harvest, with some minor limitations on quantity due to distance from road and steep terrain – and no restrictions for wetlands beyond possibly limited inventory indicated by FIA plot data. Logging residue estimates are from Timber Product Output data, which are derived from harvest volume estimates, measurements at sample harvest sites, and mill surveys. The latter two sources are considerably out-of-date for many states and likely do not reflect recent increases in utilization of previously non-commercial tops and cull trees due to developing energy markets. Available primary mill residues are also from TPO data that are likely outdated. Because of these data limitations, the BTS update may overestimate all sources of available residues, from logging to mill. Data are lacking on secondary residues, BTS does not explain the derivation of state-level estimates, and no county-level data are provided, so this source has been omitted. Construction and demolition debris and municipal solid waste are also excluded here since they are not directly related to local forest capacity, there are sorting and transport challenges, and combustion of these materials is controversial. County level secondary mill, construction/demolition, and municipal wood wastes as a percent of total BTS wood feedstock estimates range from 3% (Aroostook) to 33% (Knox) in Maine, 14% (Coos) to 57% (Strafford) in New Hampshire, and 20% (Windham) to 92% (Grand Isle) in Vermont, so if these materials are truly available and could be used responsibly they would substantially expand biomass energy capacity in some counties. The thinning regime for BTS integrated operations assumes that half of non-reserved forestland with density at 30% of the theoretical maximum for that forest type will be thinned (across all tree diameters down to 1") down to 30% of the maximum stand density over 30 years. (Integrated operations are described as "restoration harvests" but are not restricted to fire-prone systems with unnaturally dense stands. The future of this feedstock source after year 30 is not addressed – if these are truly "restoration" thinnings, they should not need to be repeated at frequent intervals). Unroaded areas are included in estimates, though cutting in these areas would occur only at higher wood prices. Since the economics of these operations depend on harvesting larger trees, integrated harvest is restricted so that pulp/sawlog material is limited to 2006 state harvest volumes (assumed to increase over time) This restriction is not limiting for Maine, but it causes New Hampshire's supply to be only 64% and Vermont's only 82% of its modeled quantity for composite operations in 2012 at $100/dry ton, with the discrepancy likely much less by 2030 since processing capacity is assumed to expand over time).

[26] Total harvest volume is currently about 19.9 million green tons for the three states. Maine = 14.59 million green tons (Maine Wood Processor Report 2010); Vermont = 2.46 million green tons (Vermont Forest Resource Harvest Report, 180,184 Mbf logs + 148,846 cords pulp + 401,245 green tons chips + 788,000 green tons firewood from 2008); New Hampshire = 2.8 million (Northeast State Foresters Association. 2011. The Economic Importance of New Hampshire's Forest-Based Economy).

[27] According to a recent USDA Forest Service technical report on northern U.S. forests[27] "demand for renewable energy could lead to integrated forest management practices designed to supply renewable woody bioenergy feedstock while simultaneously improving forest health and wildlife habitat, or short-term excessive wood removal for energy could create undesirable consequences for long-term forest sustainability." The growth:removals ratio in 2007/8 was 1.0 for Maine, 1.1 for New Hampshire, and 1.7 for Vermont; these state-wide figures include lands not actively managed for timber where removals are negligible so actively managed lands, at least in Maine and New Hampshire, are likely already seeing an unsustainable level of removals.

[28] From a 2008 EPA Region 1 data source showing FERC hydropower projects in New England, http://www.epa.gov/solar/energy-and-you/affect/hydro.html .

[29] ISO-NE Seasonal Claimed Capability Report, November 1, 2012, http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html .

[30] FERC Complete List of Issued Licenses and Issued Exemptions, http://www.ferc.gov/industries/hydropower/gen-info/licensing.asp. Exempt dams have less than 5 MW capacity at a pre-existing dam.

[31] Small hydro sites were identified by analyzing the hydraulic head (vertical drop) and flow for stretches of stream defined by typical regional penstock length. All stream reaches with power potential >10kWa were candidates. Sites were classified as small hydro (1 to 3MWa), low power (100kWa to 1MWa) - conventional (>8 feet of head) or unconventional (<8 feet of head), or microhydro (10 to 100kWa). Capacity was rated as annual mean power based on the available water resource (MWa) - annual mean flow and hydraulic head, restricted to a practical % of flow used (50% or less if sufficient to generate 30MWa since this is the small hydro definition) and practical penstock length (based on typical lengths for existing plants in region, 2,000 feet low power and 4,000 feet small hydro for New England region). The study eliminated sites where land use designation makes development unlikely and those >1 mile from roads or power infrastructure or too distant from population centers (regional measure from existing plants). U.S. Department of Energy (DOE). January 2006. Resource Assessment Report - Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants, DOE/ID-11263. http://hydropower.inl.gov/resourceassessment, accessed 12/15/10. Appendix, Assessment Results by State.

[32] U.S. Department of Energy Energy Information Administration. 2010. State Electricity Profiles, http://www.eia.gov/electricity/state/, accessed 5-24-12.

[33] Evans, Jeffrey W., Kiesecker, Joseph M., Fargione, Joseph, Doherty, Kevin, Foresman, Kerry R., Naugle, David E., Nibbelink, Nathan P., and Niemuth, Neal. Using Human-Induced Disturbance to Balance Conservation and Future Development. Running title: Disturbance, Conservation and future development,

[34] Vermont Department of Public Service. 2011 Vermont Comprehensive Energy Plan, www.vtenergyplan.vermont.gov. ISO-NE projects load growth over the next decade at 0.8% for Maine and 1.5% for New Hampshire (ISO-NE state profiles (ISO-NE. 2011 Regional System Plan, www.iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc).

[35] U.S. Department of Energy, Energy Information Administration. State Energy Data System, http://205.254.135.7/state/seds/

[36] Energy Information Administration, Office of Energy Consumption and Efficiency Statistics. 2012. Table HC10.10 Average Square Footage of Northeast Homes, By Housing Characteristics, 2009. Data from forms EIA-457 A and C of the 2009 Residential Energy Consumption Survey.

[37] U.S. Energy Information Administration. January 2012. State-Level Energy-Related Carbon Dioxide Emissions, 2000-2009.

[38] Non-CO_2 emissions from energy-related combustion were 6% of CO_2 emissions nationally in 2010. US EPA. April 15, 2012. Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2010, http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

[39] Indirect emissions are about 3% of coal combustion emissions, 18% of oil, and 26% of natural gas (Manomet Center for Conservation Sciences. 2010. Massachusetts Biomass Sustainability and Carbon Policy Study: Report to the Commonwealth of Massachusetts Department of Energy Resources. Walker, T. (Ed.). Contributors: Cardellichio, P., Colnes, A., Gunn, J., Kittler, B., Perschel, R., Recchia, C., Saah, D., and Walker, T. Natural Capital Initiative Report NCI-2010-03. Brunswick, Maine, Exhibit 6-6). The three northern New England states used about 6% of their fossil energy as coal, 71% as petroleum, and 23% as natural gas. Weighted average indirect emissions were thus about 19% of direct combustion emissions.

[40] The increase through 2050 is based on energy demand increases assumed for our scenario – see note

[41] GE Energy Applications and Systems Engineering, EnerNex, and AWS Truepower. December 5, 2010. New England Wind Integration Study. For ISO-NE.

[42] Average lifecycle GHG emissions for electricity generation in the U.S. are about 731 kg CO2e/MWh, and transmission adds 23 to 77 more kg/MWh, depending on type of transmission (Itten, René, Frischknecht, Rolf, and Stucki, Matthias. July, 2012. Life Cycle Inventories of Electricity Mixes and Grid. ESU-services Ltd. for Paul Scherrer Institut (PSI), Uster, http://www.ecolo.org/documents/documents_in_english/Life-cycle-analysis-PSI-05.pdf , Tables 5.1 to 5.4).

[43] These are conservative assumptions, as spacing is based on a mix of turbine sizes in current projects. Larger turbines would likely require greater distance between turbines, but large turbines and large numbers of turbines per site will both minimize number of developed sites and hence total landscape disturbance.

[44] Kingdom Community Wind clears 2.3 acres per 3MW turbine pad; Bowers wind would clear 2.25 to 3.3 acres per 3MW turbine pad; Spruce Mountain cleared 1 acre per 2MW turbine pad.

[45] Spruce Mountain estimates 100 cubic yards of concrete for each 2 MW turbine, which may be minimized by tying in to ledge; Dry Lake in Arizona estimates 386 cubuc yards for 2.1MW turbines; Elkhorn Valley Wind Farm 243 cuyds for 1.65MW turbines, Kittitas Valley Wind Farm in Washington largest foundation 340 cuyds for 2MW turbine, Antelope Ridge estimated 400 cuyd for 3MW turbine.

[46] ISO New England. February, 2010. New England 2030 Power System Study: Report to the New England Governors. 2009 Economic Study: Scenario Analysis of Renewable Resource Development.

[47] Project permits and Denholm, Paul, Hand, Maureen, Jackson, Maddalena, and Ong, Sean. 2009. Land-Use Requirements of Modern Wind Power Plants in the United States. Technical Report NREL/TP-6A2-45834. Table 6, p. 22.

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