Wellesley Municipal Light Plant

Greenhouse Gas Emission Reduction Study

Phase I: Near-term measures for 2018 to 2030

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Acknowledgments

This report reviews the greenhouse gas reduction potential of various actions that may be taken with respect to the generation and consumption of electricity in the Town of Wellesley. It also presents estimates of greenhouse gas reduction quantities and costs associated with electric sector measures that may be initiated by the Wellesley Municipal Light Plant (WMLP). The purpose of the report is to provide data, forecasts, and analysis for consideration by the WMLP related to opportunities for and costs of reducing the Town's emissions of greenhouse gases, with a focus on the electric sector.

This is an independent report by Analysis Group, completed through a review of past and current data and research and analysis related to regional electricity market operations and technological and economic factors related to power sector greenhouse gas reduction options. The report has benefitted from numerous discussions with staff and Board Members of the WMLP, an ad-hoc group convened by the Light Plant to provide input to and feedback on the report, staff of Energy New England (ENE), and other New England market participants. We wish to thank the WMLP, ENE, and the members of the Ad-Hoc group (listed below) for their assistance and input throughout the process. We also would like to thank Jacob Silver of Analysis Group for his input on and support of the research and analyses contained herein.

The report, however, reflects the judgment of the authors only, and does not necessarily reflect the opinions of WMLP, ENE, or members of the Ad-Hoc Group.

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About Analysis Group

Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 700 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, London, Brussels, Paris and Beijing.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including but not limited to energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies.

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Overview and Scope

In 2014, the Town of Wellesley Massachusetts established a goal to reduce its greenhouse gas (GHG) emissions from the electricity, transportation and building sectors 25 percent by 2020, relative to 2007 levels. This goal is similar to elements of the GHG reduction goals and binding requirements established for the State of Massachusetts in the Global Warming Solutions Act (GWSA), as well as GHG reduction programs and priorities of other states. In addition, the Wellesley Municipal Light Plant (WMLP) has undertaken a number of measures to reduce the GHG emissions associated with the purchase and distribution of electricity to its approximately 10,000 customers. Notably, the WMLP has achieved reductions in total GHG emissions between 25 and 30 percent over the ten year period 2007 to 2017, depending on the quantity of existing renewable energy credits to be retired.[1] These reductions have occurred due to changes in the resources and operation of the regional power system, and through WMLP investments in energy efficiency, distributed renewable resources, and targeted long-term wholesale contracts for renewable resources.

The WMLP has supported the Town's efforts, and has evaluated its GHG emission portfolio and considered various ways to reduce the GHG profile of electricity purchased or generated to meet the needs of Town's residents and businesses. To aid this effort, the WMLP engaged Analysis Group to develop a comprehensive study to evaluate the feasibility for additional GHG reductions and the potential costs and benefits to the WMLP and its ratepayers of achieving such reductions. The purpose of this study is thus to conduct a systematic review and quantification of viable potential GHG emission reduction strategies for the WMLP and its customers, and estimate the potential magnitude of GHG reductions and net costs to WMLP customers.

This "Phase I" study represents a scoping exercise that considers, based on current information and market expectations, the suite of GHG emission reduction measures that are likely to be available to the WMLP in the near-term (that is, prior to 2030). It is designed to provide the WMLP and its Board with data, information and insights that may be used to evaluate potential strategies for future GHG emission reductions, and to inform considerations related to the timing, measure, and scope of Wellesley's GHG reduction efforts. To inform near-term actions, the Report primarily focuses on measures that build from recent WMLP experience with demand side reductions in energy, supply side procurement of renewable energy, and the developing market for distributed energy resources.

A second ("Phase II") report will provide additional qualitative considerations and evaluate the impact of technological change and/or broader structural changes in the power sector that may or may not occur, and whose timing and impact are highly uncertain. Such developments could include, for example, greater penetration of distributed resources; the advanced electrification of building and transportation sectors; and the increasing use of smart meter infrastructure and time of use rates for demand side management. Further, these advanced measures may be coupled with battery storage solutions, should economic battery storage technologies reach full commercial status. There remain important questions about the economics of battery storage in the near-term and how to assess those costs relative to the multiple potential value streams to system operators and customers. Many of these value streams (such as delayed or deferred distribution capital expenses or reductions in peak demand) are complementary to, but distinct from the immediate focus of this Report on near-term GHG emission reductions.

It is possible that some measures discussed in the Phase II Report (e.g., accelerated installation of distributed renewable resources) may be commercially available at competitive prices within the 2030 timeframe. However, given the level of current installations at the residential and small commercial level in the Northeast, market price expectations, and the potential speed of deployment, these are not likely to present a realistic primary pathway to GHG reductions before 2030.[2]

Developing a supply curve of GHG emission reduction measures necessarily requires development of market and technological forecasts, and the application of professional judgement about the evolution of the electricity sector on a going-forward basis. We thus develop an initial scoping of near-term reductions that compares different reduction measures on a consistent and comparable basis, using transparent assumptions and an easily-identified analytic approach. Through this focus on transparency, the study provides actionable data and insights to the WMLP Board in a readily-accessible form that can be re-evaluated and updated as system conditions evolve in the future.

Regional and State Context

Understanding the regional context is important in considering the potential for additional and incremental actions by the Town of Wellesley. Even absent any specific action by the WMLP, Massachusetts and the New England Region will achieve GHG emission reductions through various existing market policies and procurements. In 2017, Regional Greenhouse Gas Initiative (RGGI) member states approved the new model rule, with a 30 percent reduction in the market cap relative to the prior 2020 goal, and with annual reductions of 2.275 percent each year out to 2030. At the same time, Massachusetts will achieve reductions driven by a number of different state policies. First, the Commonwealth has finalized a state-specific and more stringent cap on CO_2 emissions from in-state power plants, most of which are also subject to the RGGI cap.

State specific renewable portfolio standards (RPS) for state-regulated investor owned distribution companies will continue to increase over this time frame, with a requirement of 25 percent by 2030 from Class I renewables, including specific contributions from solar capacity. Further, the RPS in the state now functions within a broader Clean Energy Standard (CES), requiring that 80 percent of all electricity be met by low-carbon resources by 2050. In part to help meet these targets, Massachusetts has recently engaged in three large solicitations for additional clean energy, including class I renewables, off-shore wind, and large scale transmission and hydropower from Canada.[3] Other states, including Connecticut, Rhode Island, New York and New Jersey have announced similar solicitations or goals aimed at developing large scale renewables, including off-shore wind. Finally, states continue to invest heavily in cost-effective energy efficiency programs: in the 2016-2018 three year plan, MA distribution utilities identified savings of up to 4 million megawatt-hours (MWh) or approximately 3 percent of forecasted retail load.[4]

GHG Reduction Options

With the state and regional context in mind, we evaluate a similar set of GHG emission reduction measures that could reasonably be available to the WMLP in the near-term. In particular, we review two types of strategies whereby WMLP may reduce the effective level of GHG emissions associated with the Town's use of electricity. The first option involves the ***annual*** and ongoing purchase of REC/CEC from a secondary market for the environmental attributes associated with energy generated by existing resources in New England.[5] The second option involves ***longer-term investments*** in energy efficiency and the procurement of energy (and the associated environmental attributes) from low- or zero-carbon renewable, hydropower, and existing nuclear resources.

As described in this Report, these alternatives are not an either/or decision; rather, they represent potentially complementary contributions to reducing the effective GHG intensity of the electricity resources WMLP uses to meet customer demands for electricity. Different options necessarily involve tradeoffs and different types of benefits to the WMLP with respect to net cost to ratepayers, budget and price certainty, and differing levels of flexibility to adjust as program needs evolve over time. While we discuss these options separately within the context of this Report, it is important to recognize that options for reducing GHG emissions associated with Wellesley's supply and consumption of electricity could (and likely would) include the use of a mix of options (including annual and longer-term strategies) tailored to the magnitude and timing of any reduction targets identified by the Town.

Specifically, we evaluated GHG emission reductions associated with the following:

- Purchase (and retirement) of ***existing Class I RECs*** on an annual basis;
- Multiple ***energy efficiency programs***, modeled on existing distribution company initiatives for residential retrofits and measures, including lighting; residential behavioral programs; commercial and industrial retrofits; and C&I retrofit programs for small businesses;
- Market potential for additional ***distributed solar resources*** on residential buildings;
- Additional and continued ***long-term contracting*** with new ***wind*** and utility scale ***solar*** resources; and
- The possibility for new long-term contracts for resources solicited under the Massachusetts Energy Diversity Act and Clean Energy Standard, including new supplies for ***Canadian hydro imports and off-shore wind*** and contracts with ***existing nuclear resources.*** These resources likely represent larger, one-time projects and contracting opportunities.

For each set of options, we estimate both the total market potential that could be achieved and the cost of each GHG emission reduction option. By considering both the market potential of the total reduction and the unit cost, we can estimate the total cost of pursuing all GHG emission reductions identified above. It is important to note, however, that this list of reasonably likely options is not exhaustive, and that individual or project-specific opportunities for further GHG emission reductions may be available.

In this context, the supply curve of options presented here allows for a more direct evaluation of individualized projects that fall outside the scope of this analysis.

Cost, Rate, and Revenue Considerations

Our figure of merit for assessing GHG reduction costs is the *net* cost of the measure or program. The net cost of a GHG emission reduction option will depend on both the actual incurred or expected *cost* of the option in the year evaluated, and the *savings* to WMLP and customers associated with avoided purchases of wholesale energy, regional capacity and transmission services, and/or spending on local distribution infrastructure.[6] In this study we include estimates for avoided energy, capacity and transmission, based on estimated reductions in system load and peak demand associated with the GHG emission reduction option(s). Most of the options evaluated in this Phase I study achieve effective reductions in total energy consumption (or purchase of RECs for a given quantity of energy consumption), with an associated reduction in GHG emissions. However, longer-term scenarios may introduce options that reduce peak demand or shift load to off-peak hours, providing or supporting the achievement of incremental GHG emission reductions in a way that primarily reduces total costs through avoided wholesale market capacity payments.

The net cost of GHG emission reduction options, if positive, would be incurred by WMLP and collected through changes in rates charged to WMLP customers to ensure revenue adequacy for the WMLP. However, *how* rates are designed to recover net costs matters, particularly when considering the distributional effects of some of the options and approaches that would be important or necessary for achieving substantial reductions in the GHG emission intensity of energy supply across multiple sectors. A few examples highlight the importance of considering and anticipating on the one hand the impact of GHG emission reduction options on the fairness and equity of revenue collection, and on the other hand the incentives or barriers to achieving reductions tied to rate structures:

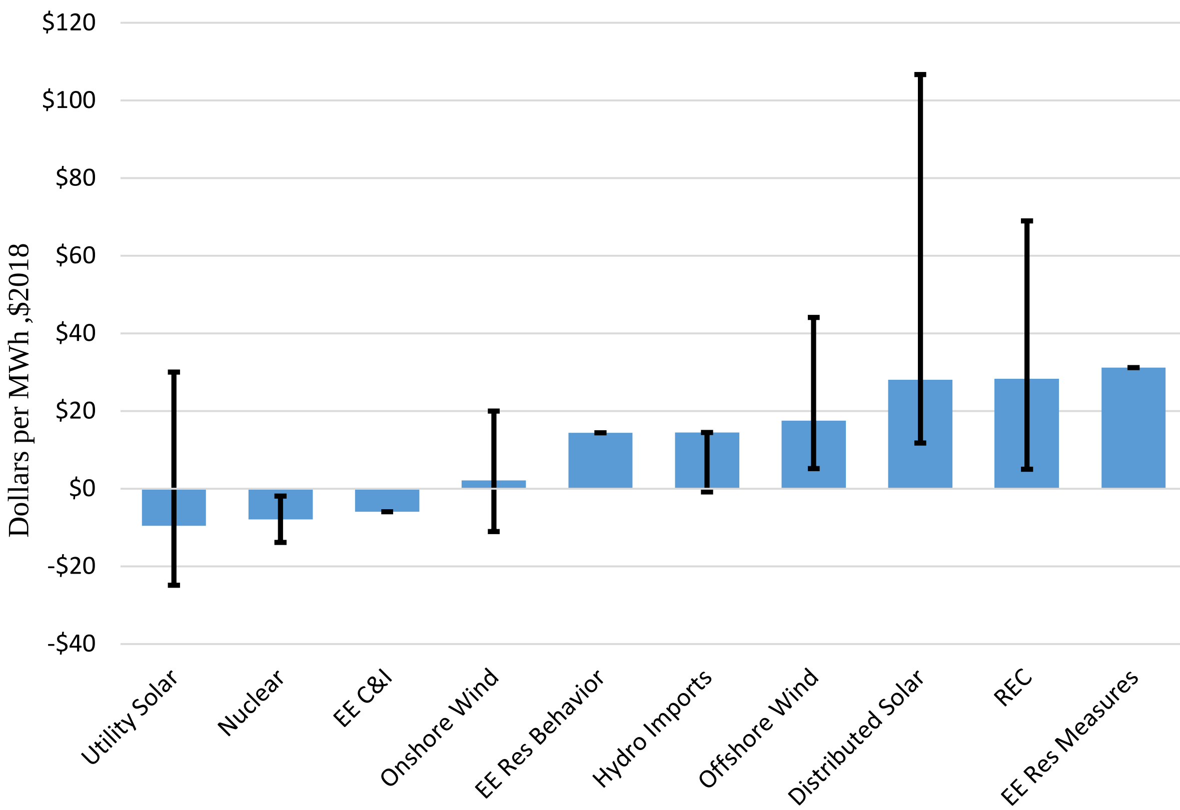
- Deployment of distributed resources located behind-the-meter reduce electricity costs of the host customer by reducing the amount paid through WMLP volumetric (i.e., per-kWh) rates; yet much of WMLP's costs are tied to fixed, non-variable investments in infrastructure (i.e., poles and wires). Significant increases in the distributed resource development (e.g., rooftop solar) to achieve GHG emission reductions may thus unfairly shift the collection of WMLP's fixed costs away from those that have rooftop solar (yet still require WMLP service) to those that, for whatever reason, cannot or do not.
- The design of rate structures over time may also have significant impact on when consumers use electricity, and in aggregate, could shift or change current peak demands. Considering this larger context may be important over a longer time frame, to the extent that solar installations increase (with or without the addition of battery energy storage), electric vehicles become more widespread as a transportation decarbonization option, and/or other technologies are adopted that allow for end-use demand management. Time-varying rates and/or other rate design approaches could provide incentives for such measures, help manage these changing use patterns, and allow for sufficient recovery of revenues for reliable operations.

- The current increasing block rates (where the price of energy increases at higher levels of consumption) encourages conservation. On the other hand, increasing block rates may discourage future electrification of transportation or building sectors. Shifting residential transportation and building gas and fuel use to electricity could increase WMLP energy demand by an additional 160,000 MWh, nearly double the existing non-GHG free portfolio. Doing so, however, could potentially reduce GHG emissions in those sectors by almost 60 percent and could be even greater if that electrification is met from low carbon resources. Thus, to the extent that Wellesley moves towards electrification as a path to decarbonization, it will be critical to anticipate such changes and consider in advance appropriate adjustments to rate design and revenue recovery.

As a starting point for the current analysis, we consider the WMLP's existing programs, supply obligations, and load forecast. By 2022, the WMLP is on track to have long-term contracts (with ownership of the associated environmental attributes) in place to meet more than 30 percent of its load from low carbon resources. This includes contracts with existing facilities used to meet current demand plus recently executed contracts that will be in effect by 2022 for new wind and existing nuclear output. Assuming flat load growth (consistent with the regional outlook for electric demand) and assuming the full retirement of associated REC/CECs, this leaves roughly 164,000 MWh of WMLP demand not presently designated to be met with low-carbon resources. Based on our review of the suite of potential near-term measures that could help meet this level demand, we observe the following for the WMLP:

<u>There are different "pathways" to GHG reductions; different pathways present important tradeoffs between feasibility, certainty, and total cost</u>: We provide supply curves for GHG emission reduction strategies in 2020, 2025 and 2030 (Figure ES 1). During this time period, total program costs for each measure will vary and so too will the relative ranking of programs. Literature and recent program experience suggest that costs for energy efficiency programs will remain roughly constant in real terms, while renewable costs (not considering federal tax subsidies) will continue to decline over time. The *net* costs of each of these programs will also depend on the energy, capacity, and transmission needs and costs avoided through the program. For example, projects that can reliably provide power coincident with summer peak (e.g., solar combined with storage) or that provide baseload power with high capacity factors (e.g., nuclear and hydro) will result in greater capacity cost reduction benefits. Projects that can reduce peak consumption, such as energy efficiency and distributed solar, will similarly reduce capacity costs and may also reduce total transmission costs for regional network service. By 2030, utility scale solar, existing nuclear, and commercial and industrial energy efficiency programs are all expected to provide net benefits to ratepayers. Long-term contracts for on- and off-shore wind, hydropower imports, and residential behavior energy efficiency programs are expected to result in net costs to ratepayers. The net cost for these programs are less than the expected middle case price of existing Class I REC purchase. However, prices for new renewable resources are uncertain, and in some instances, the high price scenario for renewables would impose greater net costs than middle case REC purchases. Distributed solar and residential energy efficiency measures are among the most expensive resources quantified here. These projects require individual home visits and site specific efforts for implementation. These programs also potentially provide benefits that are not easily quantified, including delayed or deferred distribution expenses, reductions in natural gas and water consumption, and potential health benefits from reductions in demand.

Executive Summary Figure 1: Levelized Net Cost Per MWh in 2030, $2018



Notes and Sources: Analysis Group analysis. Error bars represent low/high estimates of net costs, given uncertainty in future market or technology costs. See Section III.

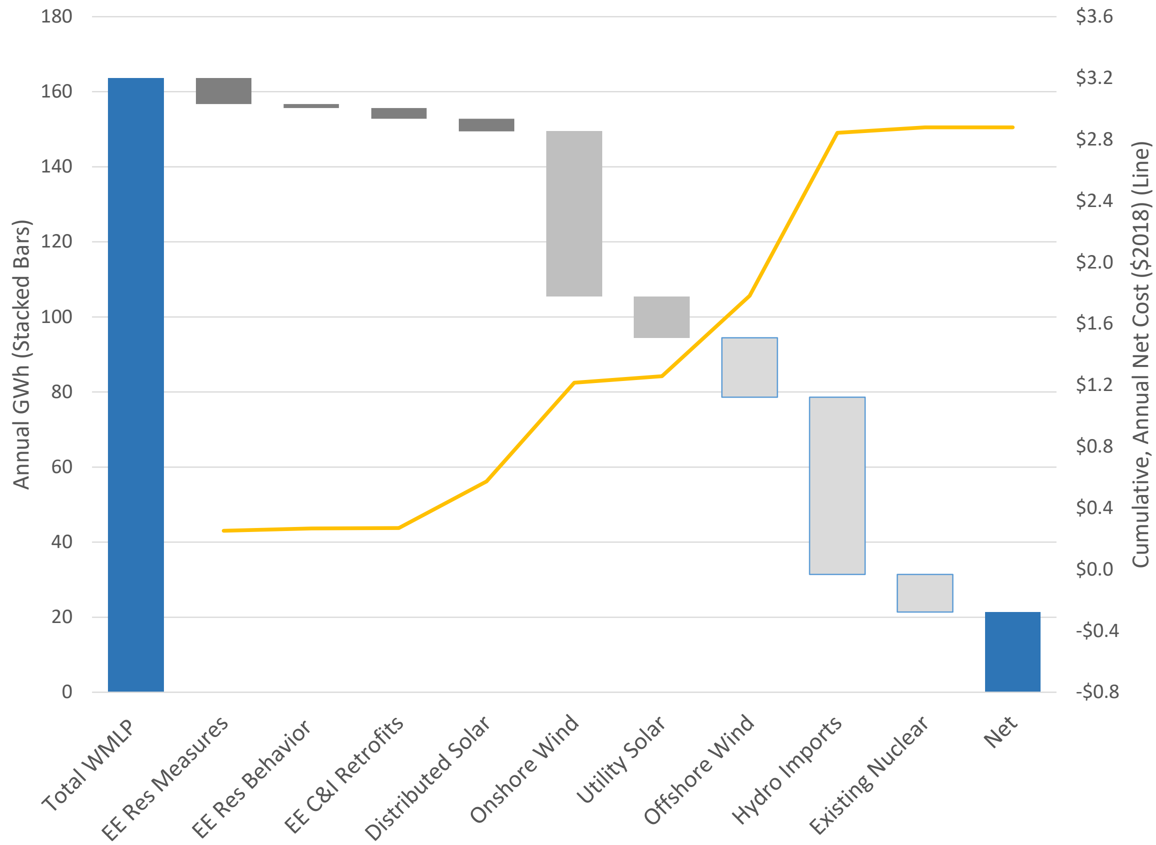
<u>There are factors other than costs and availability that are important in developing GHG emission reduction pathways, such as market uncertainty and project prioritization</u>:

Cumulatively, we find that by 2030, the market potential for resources potentially available to the WMLP could provide up to 142,000 MWh of qualifying clean energy, approximately 87 percent of the remaining WMLP portfolio needs. However, our estimates of net costs and the total market potential for various low-carbon resource options represent only one consideration for selecting GHG emission reduction pathways. There exists considerable uncertainty around the future potential for large infrastructure projects and one-time contracts with new hydropower imports, offshore wind, or existing nuclear generation. These projects may only be available in set quantities and only in a limited number of years. And these projects pose important and open ended questions and issues related to state policy actions, regional coordination, and potential impacts to market competition. However, taken together these three options account for more than 70,000 MWh of low-carbon energy or roughly 50 percent of the total identified WMLP market potential. In contrast, projects directly within WMLP's control, including energy efficiency and distributed solar, account for 10 percent of the total market potential, while long-term contracts with onshore wind and solar account for the remaining 40 percent. The market uncertainty regarding the viability and in-service dates of new procurements and regional renewable development points to two important observations. First, annual purchases of existing RECs could provide important flexibility to the WMLP in contributing to Town GHG emission reduction goals. Second, there is value in prioritizing projects like energy efficiency and distributed generation which are directly within the WMLP's control. Pursuing these projects sooner could provide experience and a foundation of communication with stakeholders and customers in considering additional, longer-term distributed resource options - such as those aimed at reducing peak demand or shifting load through the use of time- and seasonally-varied rate structures and/or distributed storage combined with battery storage. Over the long-term, however, this certainty and flexibility may come at higher net costs to ratepayers.

Net costs depend on the pathway selected: While not the primary focus of this Report, it is instructive to consider the potential range of costs to pursue the full suite of potential measures quantified here. Procurement of all long-term carbon-reduction measures effecting WMLP supply and demand would require annualized net costs to WMLP ratepayers of $2.9 million in 2030 ($2018). Monthly impacts relative to current average residential bills would be approximately $11.3 per month or a 8.3 percent increase. These reductions would reduce the remaining non GHG free portfolio by 87 percent. To meet a 100 percent reduction, the WMLP would likely need to take additional action. Purchasing and retiring additional RECs above and beyond these portfolio changes would increase total costs to $3.5 million per year.

These results rely on significant reductions from offshore wind, existing nuclear, and hydropower imports. A delay in development or reduction in available contracted capacity from these resources would require that an equivalent level of reductions be achieved through other approaches, such as the purchase of existing Class I RECs. The WMLP could also meet GHG emission reductions targets solely through the annual purchase and retirement of a sufficient number of Class I RECs. Using RECs alone, total costs would be $4.6 million per year assuming mid-price estimates for RECs (with a potential range from $0.8 million per year to $11.3 million per year), resulting in a 3.3 percent rate increase (with a potential range of 2.3 percent to 32.4 percent).

Executive Summary Figure 2: Cumulative Reductions and Net Costs in 2030 ($2018)



Notes and Sources: Analysis Group analysis. Costs represent midpoint estimates. GHG reduction measures are presented in the order described within this Report, and do not represent a recommendation or conclusion regarding any potential GHG emission reduction pathway.

Net costs would depend on the timing and implementation of the pathway selected: The total cost of a portfolio of actions will similarly depend on the timing of when those reduction measures are implemented. The net costs of each individual GHG emission reduction measure will vary over time. For example, prices for wind and solar resources currently benefit from Federal tax credits, which are set to phase out and expire by the middle of the study period. Yet at the same time, prices for these resources are expected to continue to decline independently of these tax credits, and may be lower cost at the end of the study period. Similarly, the price of existing Class I RECs will vary over the study horizon, in response to changes in supply (as new resources potentially come on line to meet state solicitations) or as total demand changes (in response to changes in voluntary consumer purchases or state procurement requirements).

An overreliance on any one strategy will tend to increase costs and WMLP risk: Taken together, the observations stated above suggest that there are costs and risks associated with "locking-in" an overreliance on any single strategy. For example, an over-reliance on retiring existing Class I REC purchases could expose the WMLP to considerable budget uncertainty, while an over-reliance on long-term contracts could reduce the WMLP's ability to respond to future changes in the electricity sector. With fully-contracted load, the WMLP would also have less flexibility to pursue new or emerging technologies. And over time, a portfolio that is overly-reliant on any one technology or approach could lead to a mismatch between generation and WMLP demand, requiring the WMLP to be more frequently exposed to wholesale market purchases and sales. These transactions could lead to either net costs or benefits over time, but may create increased uncertainty and volatility with respect to the WMLP budget and potential costs to consumers. If multiple towns or municipalities were to all pursue the same pathway based on a narrow set of options, an increase in volatility and uncertainty could extend to the broader region and potentially increase capacity costs or other investments necessary to maintain system reliability and resource adequacy.

The rest of this Report proceeds as follows. In Section I, we review existing WMLP operations to establish the baseline for the current study and highlight the two primary methods used to reduce GHG emissions, either from purchases from existing renewable markets or through direct changes to WMLP's supply portfolio. In Section II, we review the existing market for renewable energy certificates in New England, in order to characterize the opportunities, costs, and nature of this approach to reducing carbon emission impacts. In Section III, we consider more fully the suite of options that could reduce GHG emissions through direct changes in the WMLP portfolio, including our assessment and assumptions for current market prices and total market potential. In Section IV, we describe our method with respect to the development of a supply curve and the quantification of GHG emission reductions, including the potential costs and benefits for each measure in the years 2020, 2025 and 2030. We conclude in Section V with a summary of results and further considerations.

I. Pathways to Decarbonization: Context and Framing of the Options

The Context for the Phase I and Phase II Reports

In 2014, the Town of Wellesley Massachusetts established a goal to reduce its greenhouse gas (GHG) emissions from the electricity, transportation and building sectors by 25 percent by 2020 relative to 2007, consistent with the broader goals and binding regulations laid out for the State of Massachusetts in the Global Warming Solutions Act (GWSA). To help meet the Town's goals, the Wellesley Municipal Light Plant (WMLP) has undertaken a number of measures to reduce the GHG associated with the purchase and distribution of electricity to the approximately 10,000 customers in the Town. Notably, the WMLP has been able to reduce its total GHG emissions by between 25 and 30 percent (depending on REC retirement) over the ten year period 2007 to 2017[7], due to changes in both the broader regional electricity system and through investments in energy efficiency and additional long-term contracts for renewable resources. At the same time, the WMLP has continued to meet the reliability needs of its customers and provide power without interruption throughout the year. (See Text Box 1, below).

Every state in New England is asking a similar set of questions and is in the midst of developing its own plans and pathways towards greater decarbonization. Within the electric power sector, this has created important opportunities and also greater uncertainty in wholesale electricity markets. Emissions continue to fall, driven by a wide mix of regional market based policies, such as the Regional Greenhouse Gas Initiative (RGGI) which puts a price on CO_2 emissions, and state based regulations and incentives that create demand for new renewables and clean energy through Renewable Portfolio Standards (RPS) and other procurement and solicitation policies that offer long-term supply contracts for new generation from off-shore wind, large scale hydropower, and other renewables. All of these regional and state policies are overlaid by and operate within the regional wholesale electricity market administered by the Independent System Operator-New England (ISO-NE), tasked with scheduling and dispatching power supplies in every second of the year to meet the constantly changing system demand and ensure the reliable operations of the transmission system to deliver that power.

Taken together, this suite of regional and state policies points to a continued decline in emissions from the electric power sector, through greater reductions in energy use and the increased deployment of renewable energy and other clean resources. Under the RGGI emission cap, total emissions will decline from 75 million tons to 61 million tons by 2030. But there are challenges. While every state has set a goal or regulation towards greater decarbonization, differences in state policy and priorities have led to disagreements and tensions over the best path forward, increasing the difficulty to potentially site new infrastructure.[8] And other goals hinge on the successful development and maturation of new offshore wind facilities, a continued decline in renewable energy prices, and/or a sustained commitment towards energy efficiency programs. Few of these actions can be guaranteed at this time.

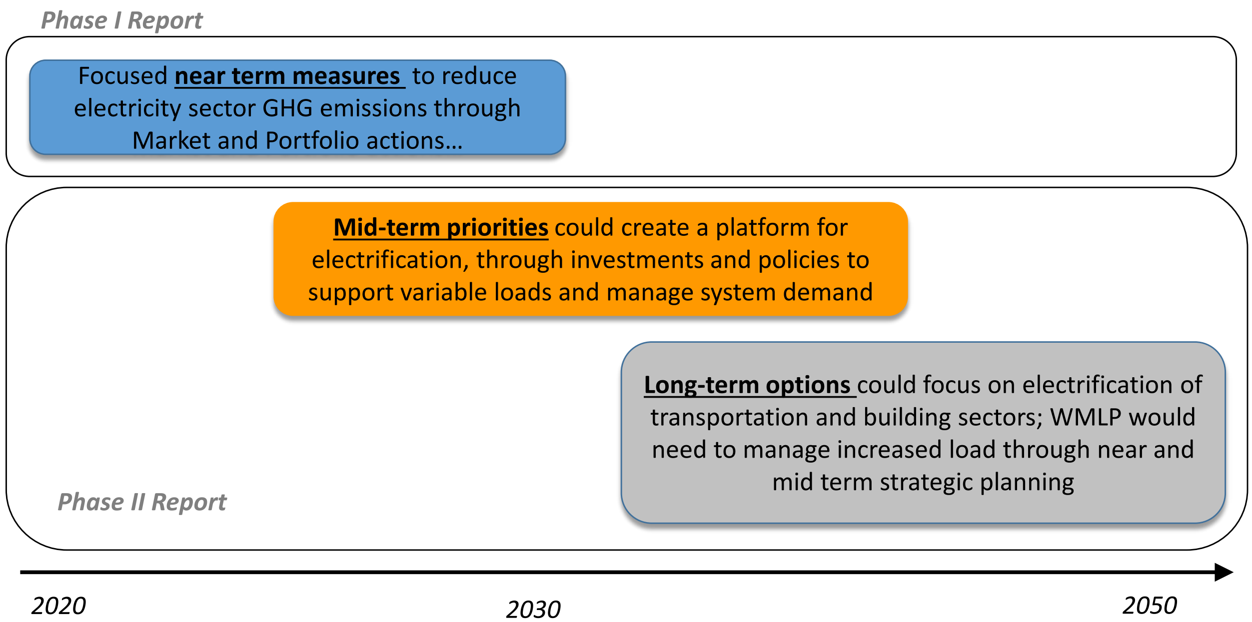
The immediate question, then, is what actions can or should the WMLP take within this broader context? And should the WMLP develop its own decarbonization pathway, in a way that provides for near-term reductions in GHG emissions while also creating a platform that could be scaled for greater change and potential electrification of the transportation and building sectors? To help in answering such questions, the WMLP engaged Analysis Group to develop a comprehensive study evaluating the feasibility for additional reductions and an assessment of the potential costs and benefits to the WMLP and its consumers. The purpose of the current study is simple: to conduct a systematic review and quantification of viable potential GHG emission reduction strategies related to the Town's consumption of electricity, including the magnitude for GHG reduction potential and costs.

In this manner, the current study seeks to provide input towards the Town's planning efforts vis-à-vis WMLP operations, and to help Wellesley consider a possible set of near-term actions, mid-term priorities, and long-term goals or targets. This study develops these inputs in two Reports. This Phase I Report focuses on near-term options that can be used to reduce GHG emissions associated with current demand and electricity use by the Town of Wellesley. A Phase II Report focuses on mid-term priorities and seeks to identify important transition points that should be considered, to the extent that the WMLP wishes to evaluate longer-term goal towards a greater electrification and decarbonization of the transportation and building sectors.

The longer-term assessment is significant, as the path is both challenging and complex. For example, a high level estimate suggests that the electrification of residential transportation and home heating could add on the order of an additional 160,000 MWh to WMLP load – an almost doubling of current non-GHG free demand. Doing so, however, could potentially reduce GHG emissions in those sectors by almost 60 percent (see Text Box 2). Future GHG reductions could be even greater than shown here if that future electrification is met from low carbon resources. Yet achieving this requires careful longer-term planning, since it will require a mix of near- and longer-term GHG reduction strategies and goals that can be scaled alongside this potential growth in electricity demand.

Figure 1 depicts the need for mid-term priorities to support more variable load profiles and greater peak demand, should longer-term Town priorities require greater electrification. These changes will increase the importance and need for investments (including battery storage) that can provide peak capacity, investment in distribution infrastructure that can handle the two way flow of electricity, a utility business model that can potentially support higher fixed charges for infrastructure, and a regional electricity system served by high fixed cost, low variable cost resources such as nuclear, hydropower, wind, and solar. The Phase II Report will discuss these mid-term and longer-term concepts in more detail. Taken together, these two Reports aim to provide a broad lens for considering the near- and mid-term considerations that may be important to achieving significant CO_2 reductions over the long-term.

Figure 1: Near-Term, Mid-Term and Long-Term Perspectives



Baseline Considerations and Framing of the Analysis

As a starting point for both studies, and in particular for considering the near-term options discussed in this Phase I Report, it is important to identify the baseline by which future actions will be evaluated. Going forward, we assume that the GHG emission intensity for wholesale purchases of electricity will remain roughly constant. This expectation is grounded in the method by which the region tracks and accounts for carbon emissions. While average emissions of the regional electricity system are likely to continue to decline in the future, those reductions will be mostly "owned" or "credited" to those entities that also own – and retire – the associated Renewable Energy Certificates (RECs) or Clean Energy Certificates (CECs) that help create that change. (See Section II for a definition of RECs.)

Throughout this Report, we assume that 1 REC or CEC is equal to 1 MWh of New England qualifying low or zero carbon energy delivered to the ISO-NE bulk power system,[9] that this 1 MWh of renewable generation displaces or avoids 842 pounds (lbs) of CO_2,[10] and that the associated RECs must be retired to achieve credit for this reduction. This rate represents the annual average marginal emission rate for all electricity generated within New England, and is approximately equal to the emission rate for a relatively new natural gas combined cycle power plant. In 2016 (the most recent year of data available), natural gas was the marginal (or last) power plant used to meet regional demand in 77 percent of all

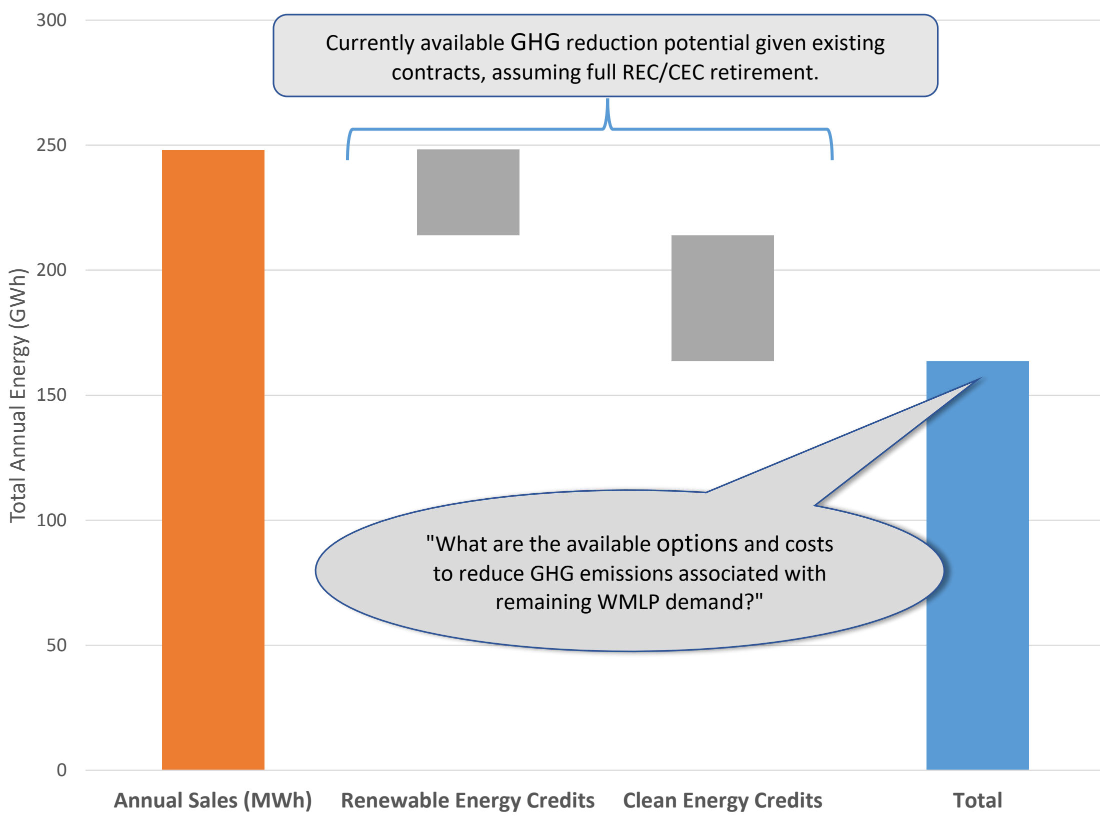
Key Assumption #1:

1 REC = 1 MWh of New England Renewable Energy = 842 lbs of CO_2 avoided

hours. Going forward, we assume that natural gas fired generation will continue to remain the marginal unit in the supply stack most of the time.

Figure 2 shows the GHG emission reduction potential for the WMLP portfolio in the year 2022. Given its history of implementing energy efficiency programs and the lack of significant regional growth in demand, the WMLP forecasts constant sales for the foreseeable future. We assume that over the study period to 2030, total system demand will remain roughly 248.2 gigawatt-hours (GWh) per year. Netted against this demand is the potential for approximately 85 GWh of Class I RECs and resource generation qualifying for Massachusetts Clean Energy Credits, including long-term contracts for generation from large scale hydroelectric and nuclear energy. These include existing contracts, plus future contracts for wind output from the Granite Reliable facility and output from the Seabrook nuclear facility that will be in effect by the year 2022. Assuming that the WMLP retires the associated Class I RECs and CECs, the total portfolio will procure approximately 34 percent of its energy from qualified clean (low- or zero-carbon) energy. This exceeds the regulations established by the MA Clean Energy Standard (CES) which requires investor owned distribution utilities to procure 20 percent of its retail obligations from clean energy resources by 2020, increasing by 2 percent per year until 2050.

Figure 2: WMLP GHG Emission Free Portfolio (2022)



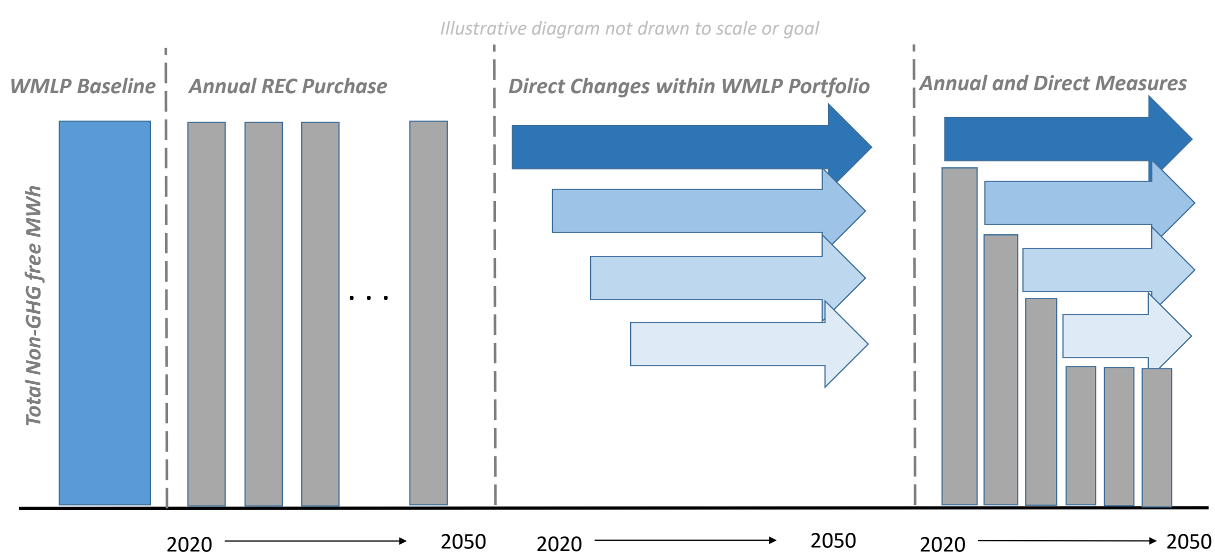
Notes and Sources: WMLP forecasts. Includes forthcoming contracts for additional wind and existing nuclear energy. Existing potential assumes the retirement of RECs associated with current or forthcoming contracts.

The remainder of this Report addresses the near-term question of "What are the available options to reduce the GHG emissions associated with the *remaining* WMLP demand, and the net costs to the WMLP and its customers associated with such actions?" The baseline quantity assumed for this study is the approximately 164 GWh of system load – or 69,000 short tons of CO_2 at the expected system emission rate – represented by the blue bar in Figure 2. Going forward, we assume that the WMLP will renew or replace non-GHG emitting contracts upon expiration with similar purchases.

Options and Approach

Going forward, there are two primary strategies and options that could reduce the GHG emissions associated with WMLP's 164 GWh of remaining electricity demand. The first option involves the ***annual*** and ongoing purchase of RECs/CECs from a secondary market for the environmental attributes associated with energy generated by resources in New England. The second option involves ***longer-term investments*** in energy efficiency and the procurement of energy sources (and the associated environmental attributes) from renewable resources, hydropower, and existing nuclear output. These approaches do not represent an either/or binary decision; rather, they are potentially complementary strategies along a pathway to decarbonization of an electricity portfolio. Each set of options – annual and ongoing purchases of existing RECs and long-term investments in new resources – would necessarily involve tradeoffs and benefits to the WMLP with respect to net cost to ratepayers, budget and price certainty, and differing levels of flexibility to adjust as program needs evolve over time. While we discuss these options separately within the context of this Report, it is important to recognize that any selected pathway to decarbonization would likely need to involve the use of both strategies. To inform this choice, the remainder of this Report is devoted to examining the suite of these options in greater detail.

Figure 3: Illustrative and Representative Pathways to GHG Emission Goals



In Section II, we evaluate the tradeoffs and annual costs associated with the purchase of RECs/CECs from the secondary market. In Section III, we evaluate a supply curve of options for long-term investments that could be implemented to achieve carbon reductions. This Section details our quantitative analysis for the feasibility and market potential of each option, and for each option the associated program costs, and the potential benefits that would accrue to customers in the form of avoided purchases of electricity, capacity, and transmission services from the wholesale market.

Developing a supply curve of GHG emission reduction measures necessarily requires the use of both forecasts and judgements about the evolution of the electricity sector going forward. An important aim of the current study is to develop a view of near-term reductions that allows for the comparison of different reduction measures on a comparable side by side basis, using transparent assumptions and an easily identified methodology. Through this focus on transparency, the study provides actionable data and insights to the WMLP Board, with results that can be evaluated and updated as system conditions necessarily continue to evolve in the future.

Text Box 1: System Reliability: WMLP's First Priority

Throughout this Report, we quantify the net costs to WMLP consumers for various GHG emission reduction strategies. We include potential benefits for the avoided cost of energy and the avoided cost of capacity. Both are critical to meeting system reliability goals. System reliability is broadly, the ability to meet customer demand in every minute of every day throughout the year.

Capacity is the total size of an energy generating unit. Capacity is measured in megawatt (MW) or kilowatts (kW), where 1 MW = 1000 kW. **Energy** is measured in mega-watt hours or kilo-watt hours (1 MWh = 1000 kWh) and represents how much energy is generated (or consumed) over time. For example, a 30 MW wind farm might contain 15 wind turbines, each 2 MW in size. During peak production, and operating at 100 percent capacity, these wind turbines could provide 30 MWh of energy during a single hour.

In 2016, total annual energy demand in Wellesley was approximately 238,000 MWh. The peak demand of 60 MW occurred in August. The WMLP met these two distinct needs through a combination of long-term contracts with power generators, and by buying power from the ISO-NE wholesale energy market in real-time, when its contracts could not cover necessary demand. This could occur if the contract generator couldn't provide power at that moment, or if the WMLP chose (for financial or operational reasons) to have fewer long-term contracts than total demand.

Resources within the ISO-NE system or included in WMLP long-term contracts operate at different levels throughout the year, based on when the sun is shining, the wind is blowing, or how economic it is to dispatch a unit based on its cost of operations. The **capacity factor** defines the percentage of hours that a unit actually operates, and measures its total output relative to a theoretical maximum output if it operated in all hours of the year. Table 1 illustrates the capacity factors used in this Report and the implications for the requirements to meet both the energy and capacity needs of the system.

Table 1: Capacity Factors by Technology Resource

			Capacity(MW) needed to meet:	
Resource	Annual CF	Peak CF	Annual Energy	Peak Demand
Onshore Wind	25%	5%	109	1200
Offshore	44%	20%	62	300
Solar (Utility Scale and Distributed)	14%	26%	194	231
Nuclear	90%	100%	30	60
Hydropower	100%	100%	27	60

We discuss the implications of Table 1 for the WMLP as it relates to constructing a portfolio to meet its annual energy needs, peak capacity demand in greater detail in Section V.

Text Box 2: The Importance of Electrification

The Wellesley Sustainable Energy Committee (SEC) tracks and publishes an annual accounting total Town GHG emissions from electricity, building energy use, and transportation. In 2016, the SEC identified total emissions of 356,102 metric tons of CO_2, with the two largest categories coming from gas/diesel use for transportation and residential energy use, including electricity and home heating from natural gas and fuel oil.

Going forward, the potential electrification of these sectors – that is, shifting current residential energy use for transportation and home heating from distributed fuel combustion to electricity – could offer reductions in Town-wide GHG emissions. As a starting point, and to inform future discussion of these issues, we provide an order of magnitude estimate of these potential savings. Specifically, we estimate that the total technical potential of electrification could reduce Town GHG emissions in these sectors by more than 50 percent, based on average vehicle fuel efficiency, the carbon content of gasoline and other heating fuels, and the current carbon intensity of New England electricity generation (average marginal emission rate of 842 lbs CO_2 per MWh).

Notably, the potential electrification of these sectors would roughly double WMLP's current remaining non-GHG free electricity demand, adding an additional 160,000 MWh to be procured and delivered by the WMLP. Future GHG reductions could be even greater than shown here if that future electrification is met through low carbon resources. Doing so would require a mix of near-term GHG reduction strategies and mid- to longer-term goals that can be scaled alongside this potential growth in electricity demand.

Table 2: Technical Potential for Electrification of Residential Transportation and Building Use

	Total MWh	Total Estimated CO_2 (Metric Tons)	Net Electric CO_2 (Metric Tons)	Percent Reduction
WMLP Electricity Demand, GHG Sources (2020)	***160,000***	***62,585***	***62,585***	
Technical Potential for Electrification (Indicative Estimate)				
Residential Transportation	87,000	109,068	33,405	69%
Residential Heat	72,000	34,382	27,684	19%
Total	***159,000***	***143,450***	***61,089***	***57%***

Note: At the time of this Report, the Town-wide SEC estimates and accounting framework for transportation related GHG emissions are preliminary and under development. The analysis presented here provides an illustrative assessment based on regional averages for fuel efficiency carbon intensity and vehicle miles traveled. The Phase II Report provides additional detail on the assumptions and method used to develop these estimates.

II. Annual Investments in Existing Resources: The Market for Renewable Energy Certificates and Implications for GHG Emission Reductions

REC Markets within New England and Massachusetts

Within New England, state-specific renewable portfolio standards (RPS) and renewable energy certificates play an important role in the development of renewable resources. A REC is simply a MWh of electricity generated by a qualified renewable resource, as defined under the state specific RPS. In Massachusetts, distribution utilities and competitive suppliers are required under the state RPS to procure at least 13 percent of their retail load in 2018 from Class I eligible resources.[11] This requirement increases by one percent per year, up to a 25 percent obligation in 2030. In addition, distribution utilities, competitive suppliers and municipal light plants also purchase additional renewable energy to support voluntary customer demand above and beyond the state RPS obligations. In Wellesley, 11 percent of customers participate in these voluntary programs, which ranks in the top five in the nation.[12]

In December 2017, the Massachusetts Executive Office of Energy and Environmental Affairs (EOEEA) promulgated a new Clean Energy Standard (CES) under Section 310 CMR 7.74. This CES serves to broaden the goals of the state RPS. Under the CES, utilities and competitive suppliers must procure clean energy at increasing quantities of load. The standard starts at 16 percent in 2018 and increases by 2 percent per year, up to 80 percent by 2050. The standard works similar to the RPS, with participants demonstrating compliance through clean energy certificates or alternative compliance payments. Clean energy is defined to include all energy procured through the RPS, plus any energy source with a demonstrated net lifecycle analysis of GHG emissions at least 50 percent below the most

Geographic Considerations

By creating demand for the environmental attributes of renewable generation, RECs offer an additional revenue source to project developers, above and beyond the energy (or capacity) value of a resource. State policy often uses this revenue to help incentivize development that might not otherwise occur.

In practice, the WMLP could obtain RECs from renewable energy projects sited outside of New England. However, without a detailed understanding of the associated portfolio standard in those regions, it is difficult to determine if those RECs offer incremental revenues that potentially support new development or if they simply provide additional revenue to existing or otherwise financially viable projects.

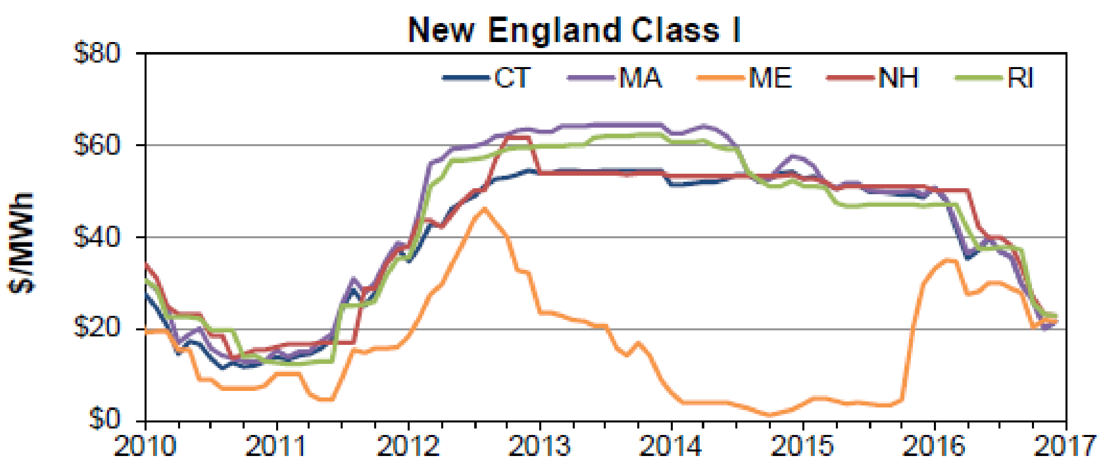
The WMLP and Town residents have both stated that an important goal in purchasing RECs is the support of new renewable energy projects. To that end, In this Report, we focus solely on Massachusetts Class I RECs, which must be created by generation in New England or interconnected regions.

For more information on mandatory and voluntary REC markets, see: https://www.epa.gov/greenpower/renewable-energy-certificates-recs efficient natural gas generators.[13] This includes baseload hydro procured under Section 83D and nuclear energy.

To demonstrate compliance with the RPS or CES, distribution utilities and suppliers must purchase or generate and then retire sufficient RECs (or CES) to meet their obligation. RECs can be obtained through long-term, bilateral contracts between a distribution utility and a renewable energy project. RECs can also be purchased annually through a secondary or open market, where in any given year, the price of a REC will be a function of both total renewable supply and total unmet demand. Notably, in many states (including Massachusetts) the price of RECs is bounded by an Alternative Compliance Payment (ACP). In Massachusetts, the ACP is made to the Clean Energy Consortium (CEC), and used to fund basic and applied research in order to accelerate the development and deployment of future clean energy technologies.[14] In one sense, an ACP can be thought of as a long-term investment in lowering the price of future RECs, with a goal of technological advancement. In 2018, the ACP for Class I resources is $68.95/MWh, and increases each year based on inflation.[15]

The price of RECs on the open market is a function of supply and demand in any given year, based on the total generation of renewable resources, retail load and REC demand (including voluntary purchases) and the use of banked or surplus RECs from prior years. Figure 4 shows the price of class I RECs in the New England region over the past several years. Figure 4 also shows that REC prices within the region tend to move together, which is due to the fact that RECs generated in one state can often be used to meet compliance in another state. In 2015, MA specific resources were used to meet 32 percent of all RPS Class I obligations, followed by Maine (24 percent), New York (14 percent) and Canada (12 percent).[16]

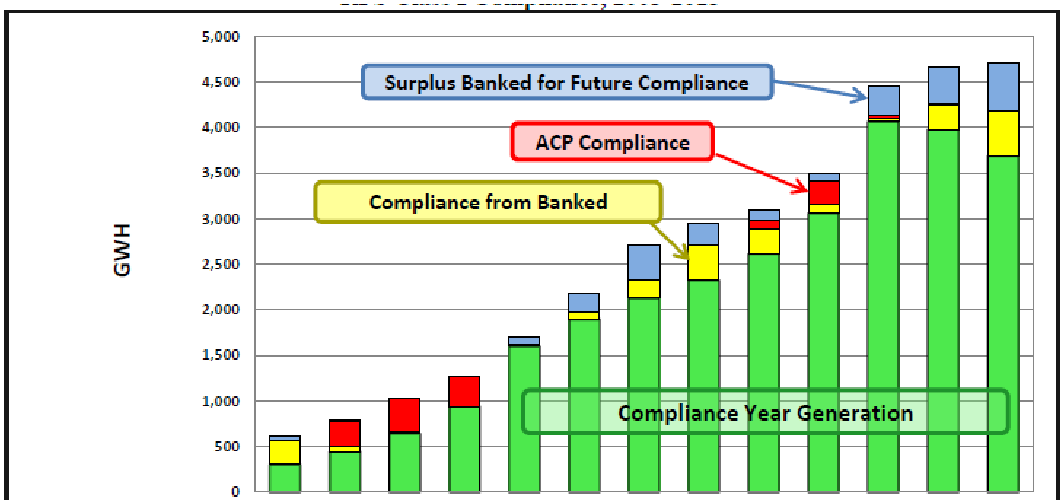
Figure 4: New England Class I REC price by year (2010-2017)



Source: Barbose, Galen. "U.S. Renewables Portfolio Standards: 2017 Annual Status Report," July 2017, Prepared for Lawrence Berkeley National Laboratory.

In 2017, REC prices reached a near five year low. This is due to the increase in renewable generation, and the fact that in recent years, total REC supply has exceeded REC demand.[17] In 2015, participants banked an additional 520 GWh of RECs for use in future years, which represents nearly 15 percent of the total 2015 obligation of 3,689 GWh.[18] This suggests that in isolation – and absent additional demand from non-obligated entities (such as other municipal light plants (MLP)) – there may be sufficient banked RECs such that the WMLP could purchase and retire RECs for the full 160 GWh of its remaining portfolio.

Figure 5: RPS Class I Compliance, 2003-2015



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Surplus Banked	61	20	1	9	81	211	386	241	108	70	329	404	520
ACP Compliance	0	265	368	323	11	1	0	4	106	255	32	6	8
Compliance from Banked	255	61	20	2	7	81	190	381	271	107	31	273	487
Compliance Year Generation	304	445	645	939	1600	1896	2130	2324	2613	3057	4064	3980	3689

Source: DOER, Massachusetts Renewable & Alternative Energy Portfolio Standards: Annual Compliance Report for 2015, October 10, 2017, Figure 1.

Going forward, the price and availability of Class I RECs will depend significantly on regional energy policy and changes in regional demand. Several other MLPs are considering large purchases of Class I RECs as well, which taken together, is likely to put upward pressure on the availability and price of existing RECs. At the same time, MA distribution utilities are currently soliciting and seeking long-term contracts for up to 16.5 GWh of additional clean energy, much of which would likely qualify as a Class I RECs. (The remainder will likely qualify for CECs as well. See Appendix I for additional detail on current MA policies and procurements).

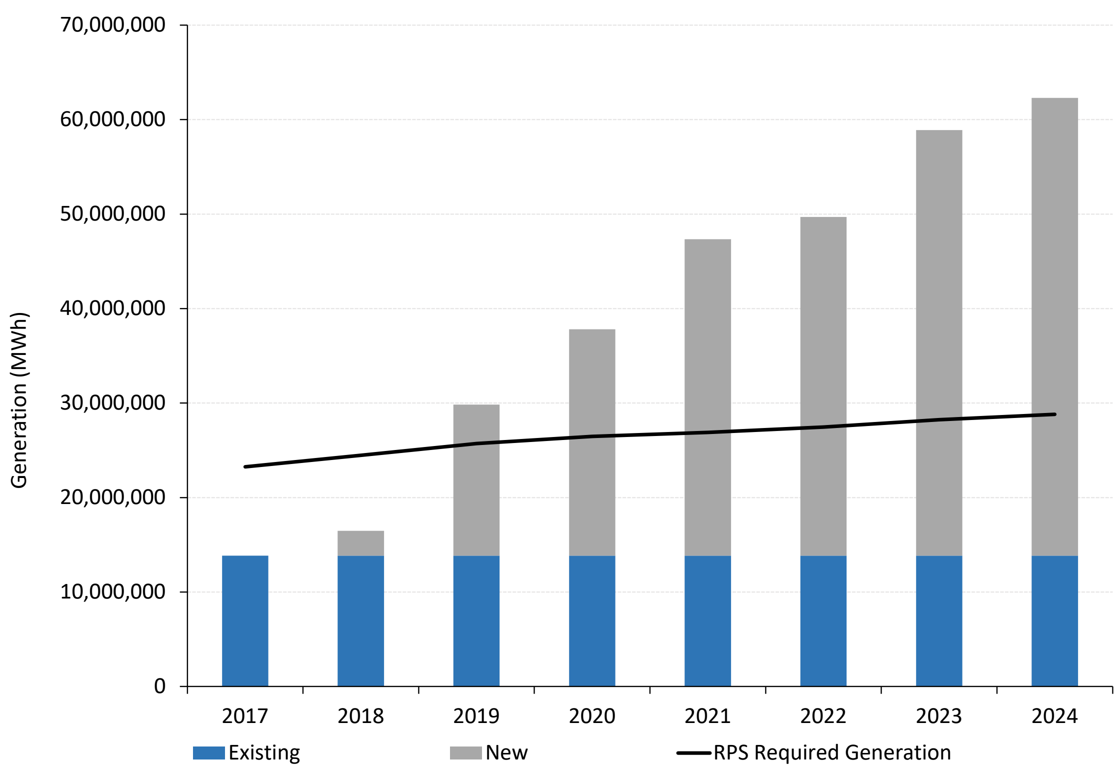
The potential for new eligible resources could cover future RPS demand. Based on the ISO-NE interconnection queue, and as shown in Table 3 there are more than 15,000 MW of potential new renewable projects, including off-shore wind.[19] As shown in Figure 6, based on historical capacity factors, these resources could provide more than 48,500,000 MWh of new generation, enough to meet and exceed regional forecasted energy demand.[20] This gap is important, because ISO-NE notes that historically, close to 70 percent of all projects within the interconnection queue are withdrawn, for a variety of reasons.[21] Figure 6 demonstrates that potential supply exists, and given appropriate market conditions, could enter the market to meet demand.

Table 3: ISO-NE Renewable Nameplate Capacity (MW) - Existing and Interconnection Queue

Category	2018	2019	2020	2021	2022	2023	2024	Total
Onshore Wind	845	3,317	1,801	750	780	0	0	7,493
Offshore Wind	0	0	0	1,620	0	2,363	880	4,863
Solar	63	1,106	293	0	0	0	0	1,461
Biomass	0	0	37	0	0	0	0	37
Landfill Gas	0	0	0	0	0	0	0	0
Storage	0	512	504	250	0	0	0	1,266
Summary								
Annual Additions	908	4,935	2,634	2,620	780	2,363	880	
Cumulative Total Additions	908	5,843	8,477	11,097	11,877	14,240	15,120	15,120
Share of Annual Additions								
Maine Wind	87%	67%	68%	29%	100%	0%	0%	49%

Notes and Sources: ISO-NE, 2017 CELT Report; ISO-NE Active Interconnection Queue, February 2018.

Figure 6: Future RPS Eligible Generation (MWh), ISO-NE 2018-2024



Sources: ISO-New England 2017 CELT Report; ISO-NE Active Interconnection Queue, February 2018; LBNL RPS Demand Projections, July 2017.

A recent study for the Northeast Clean Energy Council and Mass Energy (NECEC Report)[22] found that given current state policies, renewable resource supply could - under certain conditions - exceed the demand for RECs under current RPS policies. That study assumed the full implementation of the MA Energy Diversity Act and other regional procurements, and found that under current RPS policies of 25 percent by 2030, REC prices could approach $5/MWh by 2030. The NECEC Report argued for an increase in the MA RPS standard, in order to provide stronger financial support and incentives for new and existing renewable resource development. Increasing standards in any state would place upward pressure on REC prices.

Implications for the WMLP

Going forward, the practical implication is that Class I RECs may continue to be available to the WMLP for purchase on an annual basis through the open market. The annual cost to the WMLP for this option is relatively straightforward – it is the annual cost of a REC multiplied by the total quantity sought by the WMLP.

Table 4 illustrates the total costs to the WMLP to procure 164 GWh of RECs – enough to cover its full portfolio of emissions – at three prices: a) lower bound, using the NECEC Report estimate for $5/MWh b) a mid-point estimate of $26.50[23] and c) the upper bound Alternative Compliance Payment. Based on current residential rates and average residential consumption, the purchase of 164 GWh of RECs would be expected to increase monthly bills by anywhere from 2 percent to 32 percent.

Table 4: Annual Costs ($2018 millions) of REC purchases
To reduce GHG emissions from 164 GWh of electricity

Assuming REC prices of:	$5/MWh	$28.30/MWh	$68.95/MWh
Annual Total Cost ($2018 millions)	$0.8	$4.6	$11.3
Average Montly Bill Impact for WMLP residential customer using 975 kWh per month			
Average Monthly Residential Bill Impact	$3	$18	$44
Percent Change:	2.3%	13.3%	32.4%

Note: The average monthly residential bill of $137 and 975 kW is based on reported 2016 sales and revenues for WMLP residential customers.

Historically, the WMLP has bought or sold Class I RECs as necessary to meet the voluntary renewable commitments of WMLP ratepayers. The WMLP obtains RECs through its long term contracts with wind facilities (Spruce Mountain, Saddleback Mountain, and Canton Mountain). In 2012, 2013 and 2014, the WMLP purchased additional Class I RECs to meet customer demand. In contrast, in 2015 and 2016, existing WMLP long-term contracts produced RECs in excess of voluntary customer demand. The WMLP sold these additional RECs and used the revenues from these REC sales to offer solar rebates and municipal lighting retrofits. In 2016, total RECs owned by the WMLP were 14,884. WMLP used 7,619 RECs to meet voluntary demand and sold the remaining 7,265 at an average price of $16.25/REC for total revenues of $118,056.[24] REC sales represented approximately 3 percent of the WMLP total retail load. In 2017, the WMLP also retired and sold similar quantities of RECs associated with its long-term wind contracts, retiring 7,685 and selling another 7,469 Class I RECs.[25]

The purchase and retirement or sale of RECs involves several tradeoffs for the WMLP. On the one hand, the purchase and retirement of RECs provides an immediate and flexible option to reduce GHGs by any quantity in any given year, depending on factors such as market conditions and Town goals. Given generally available quantities, it could possibly be used as the only strategy to achieve *effective* GHG emissions, or could be used as a targeted supplement to other resource driven options.

On the other hand, the use of existing RECs to reduce GHG emissions would pose several questions for WMLP and its consumers. First, the use of year-to-year REC purchases can increase uncertainty for both the WMLP and renewable energy developers. Second, the WMLP by itself represents only a minor portion of the total REC market, and WMLP purchases – by themselves – may be unlikely to influence market prices. Finally, annual variations in REC prices may make it more difficult to forecast and develop annual budgets, and significant changes in REC prices could lead to under (or over) investments, and delay the financing of resource-specific options more directly within the WMLPs control.

There are a number of other important perspectives and considerations for the WMLP as it relates to REC purchases. For example, to what extent would the use of RECs purchased on the open market reduce or otherwise limit the reach and extent of WMLP's ability to incentivize development of new low-carbon resources? On one hand, at the upper end of costs, payments into the ACP could represent an important investment in future renewable resource technology developments. On the other hand, by itself, the WMLP purchase of RECs may not significantly affect market prices or quantities available year to year. In theory the purchase by WMLP of RECs would place upward pressure on prices and incentives for new resource development, while the selling of existing RECs would tend to maintain market prices consistent with RPS standards. In practice it is less clear what the actual magnitude of impact would be over time from a resource development and carbon-reduction perspective. Some analysts have raised the concern that sustained low REC prices may not provide the necessary financing to provide incentives for incremental or new renewable energy demand. The NECEC Report above asserted that "[s]ustained surplus and low REC prices may impair the financial viability of existing Class I resources and are not likely to enable the financing required for new renewable development, ***undermining the use of the RPS as a means to achieve the Commonwealth's climate goals***." (emphasis added)

Others have noted that an increase in volatility of REC prices can raise the financing costs and overall project costs for new development of renewable resources. The long-term revenue certainty associated with fixed contracts was one of the motivations cited by the MA DOER for moving from the prior Solar REC market to the currently proposed SMART program.[26,27] Finally, the use of open market RECs in the short term does not help offset or hedge the purchases of energy and capacity from the wholesale energy market, as direct contracting with resources may.

The WMLP will need to consider and balance these various tradeoffs between annual market purchases of RECs and longer-term investments or contracts in specific low-carbon resources (discussed in more detail below). In either instance, the WMLP would need to retire any associated RECs that it owns or purchases in order to take credit for associated environmental attributes and GHG emission reductions, or alternatively sell the RECs and use the associated funds for incremental GHG-reduction initiatives.

III. Long-term Investments In New Programs and Direct Emission Reductions Within the WMLP Portfolio

The WMLP has a demonstrated history of achieving GHG emission reductions through investments in energy efficiency, distributed solar, and long-term contracting for zero carbon resources (and the associated RECs). In the near-term, this represents another set of options to continue to reduce GHG emissions. A key benefit of these direct action options is that they enable the WMLP to exercise some control over the timing, quantity and contract length of each measure. On the other hand, these options may have a longer lead time to develop and implement, and there exists greater uncertainty going forward about the full market potential of each option that could be available to the WMLP.

In this Section, we evaluate a set of GHG emission reduction measures that could reasonably be available to the WMLP in the near-term. These GHG emission reduction measures would extend and deepen the WMLP's current efforts with energy efficiency and the long-term contracting of renewable supplies, based on existing program experience and contracting experience. Specifically, we evaluated reductions associated with:

- Multiple types of ***Energy Efficiency programs***, including initiatives for residential retrofits and measures, including lighting; residential behavioral programs; commercial and industrial retrofits; and C&I retrofit programs for small businesses;
- Market potential for additional ***distributed solar resources*** on residential buildings;
- Additional and continued ***long-term contracting*** with new and existing ***on-shore wind***, ***utility scale or community solar*** resources; and
- The possibility for new long-term contracts with ***Canadian hydro and off-shore wind*** projects developed under the recent MA Section 83C and 83D procurements and/or with ***existing nuclear generation*** sited within the region.

As discussed in Section I, there are additional measures that the WMLP may wish consider as part of its mid-term assessment options. These programs include measures such as new rate structures or battery storage that would provide the WMLP with additional ability to shift load from on-peak to off-peak periods, thereby lowering total capacity payments and potentially avoiding or deferring future distribution expenditures. Such measures would have an incremental GHG emission impact. In 2016, the ISO-NE found that the marginal emission rate during on-peak hours was 892 lbs CO_2/MWh while the off-peak marginal emission rate was 807 lbs CO_2/MWh. By shifting demand from on-peak to off-peak periods, these measures would provide GHG emission reductions of approximately 85 lbs CO_2/MWh. We discuss these measures in the Phase II Report, which focuses on mid-term decision points and long-term considerations regarding future changes to the electricity grid, the regulatory environment and utility business models.

Developing a supply curve of the GHG reductions associated with increased energy efficiency and long-term contracting of renewable resources requires the consideration of three issues a) the market potential and feasibility of each GHG emission reduction option; b) the potential costs and c) the potential benefits of wholesale/distribution cost savings. As discussed above, for each option, we assume that 1 MWh of clean or renewable energy or reduction in consumer demand is equal to 842 lbs of CO_2. We review each of these issues in turn.

Market Feasibility and Program Costs

Based on existing contracts, the WMLP is fully hedged through 2019 and 80 percent hedged in 2019/2020.[28] These contracts include approximately 37 million kWh of renewable energy from hydropower and wind resources.[29] The WMLP has added wind in increasing quantities starting in 2011 and most recently added approximately 6,000 MWh from the Canton wind facility. The WMLP is also set to add additional long-term contracts for the existing output and capacity of the Seabrook nuclear facility, over the 10 year period 2020 through 2030. This contract could add approximately 40,000 MWh of clean energy credits by 2022. And the WMLP is currently engaged in discussions to add additional wind resources of approximately 7,800 MWh in a similar time frame. In total, the combination of existing contracts and these additions for new wind and existing nuclear would total approximately 85 GWh of zero carbon energy. (See Figure 1) WMLP's current contracts provide cost certainty through 2020, but also limit the potential for immediate GHG emission reductions that could be available from additional renewable procurements in the period 2018 to 2020. For the purposes of this analysis, we assume that additional direct measures begin in 2020 or later.

Definitions of "Feasibility"

Throughout this report, we focus on the feasibility of future GHG emissions associated with the "market potential" of resources that are likely to be available to the WMLP.

Market potential is typically defined as the set of resources that are likely to be available and purchased at prevailing prices, after consideration of other market adoption barriers.

In contrast, *technical potential* refers to the maximum quantity that could be achieved, irrespective of cost. While *economic potential* refers to the full suite of cost-effective resources.

To quantify market or achievable potential, we often assume that the WMLP will be able to purchase additional clean energy or energy efficiency in a similar proportion (based on total sales) as other distribution utilities.

Residential customers, which make up the majority of WMLP's sales, are billed for energy consumption using a tiered rate structure, with separate summer peak rates.[30] Based on total WMLP revenues and sales, the average residential rate in Wellesley in 2016 was approximately 14 cents/kWh and average residential monthly consumption was 975 kWh, for an average monthly utility bill of roughly $137 per month. In Massachusetts as a whole, the EIA estimates that the average residential rate in 2016 was 19 cents/kWh and average residential monthly demand was 599 kWh. We use this rate information to express annualized program cost data as a percentage of total customer bills.

We review market feasibility and cost assumptions for programs that reflect changes in system demand (energy efficiency programs and distributed solar) and programs that reflect changes in supply through long-term contracts, below.

Demand Side Reductions

Energy Efficiency

The WMLP serves approximately 10,000 customers, the majority of which are residential single family homes. Table 4 provides WMLP sales by customer class for the period 2011 to 2016, based on WMLP annual reports. Total energy sales have declined from a peak of 247 million kWh in 2013 to less than 238 million kWh in 2016. Going forward, the WMLP forecasts total annual electricity sales of 248.2 million kWh in each year over the five year period 2018 to 2022.[31,32] For the purposes of this report, and consistent with the WMLP forecast, we assume that total sales will remain constant out to 2030, absent additional investments in energy efficiency.

Both large commercial customers and municipal lighting demand have reduced energy consumption over this period. These efforts are due, in part, to the actions taken by the WMLP. Beginning in 2011, the WMLP Board approved funding for the LED retrofit of streetlights, with the final investment for completion of the remaining lights issued in March 2017.

Key Assumption #2:

Going forward, WMLP annual demand will remain constant. Future energy efficiency savings from large commercial customers are included in this baseline.

The WMLP estimates that these retrofits will reduce municipal lighting demand by 1.5 million kWh per year, relative to 2006 levels.[33] Large commercial/industrial customers include Babson College, the Wellesley Office Park Association, and Sunlife Financial.[34] These four customers account for approximately 20 percent of total system demand and have achieved annual savings of approximately 2.4 percent per year over the past five years. Babson College accounts for approximately half of total system energy demand among these four large customers, and has identified a goal to reduce GHG emissions associated with energy use by 70 percent below 2006. Babson has reduced total energy use by 7 percent between the period 2006 to 2014, with additional plans for sustained reductions.[35] Going forward, we assume that these four large customers will continue to seek energy efficiency measures, and that these efficiency savings are included in the WMLP baseline forecast for sales.

The WMLP has funded several residential energy projects, including the Power to Save Program and the More Power to Choose Program. Under the Power to Save Program, the WMLP offers free energy audits to all homes, including the approximately 30 percent of homes that do not heat with natural gas. The WMLP also offers rebates for the purchase of energy efficiency appliances. Under the More Power to Choose campaign, the WMLP offered one-time rebates for the installation of rooftop solar. As discussed below, this resulted in approximately 600 kW of capacity. The WMLP also offers residents a 100 percent credit for net metering of distributed solar power without any cap on total production.

Table 5: WMLP Sales by customer class, 2011 – 2016

Customer Class	2011	2012	2013	2014	2015	2016	*Forecast*	Share (2016)	CAGR (2011-2016)
Sales (MWh)									
Residential	106,111	104,519	106,355	104,238	106,097	104,059	*109,208*	44%	-0.4%
Small Commercial	65,763	67,297	67,873	66,272	66,760	65,869	*69,496*	28%	0.0%
Large Commercial	53,241	51,860	51,360	51,266	50,571	47,191	*49,640*	20%	-2.4%
Municipal and Other	14,450	19,368	21,730	21,714	21,601	21,734	*19,856*	8%	8.5%
Total Sales	**239,564**	**243,044**	**247,319**	**243,491**	**245,029**	**238,855**	*248,200*	**100%**	**-0.1%**
Residential Customers	**8,847**	**8,870**	**8,844**	**8,866**	**8,861**	**8,898**		**88.20%**	**0.12%**

Notes and Sources: WMLP Annual Reports. EIA 861. Municipal demand increased in 2012 due to the opening of the new High School. Municipal demand for lighting decreased by approximately 2 percent per year over this time period, consistent with investments in an LED retrofit program.

To develop our estimates for energy efficiency program options, we rely on publicly available data submitted by MA distribution utilities as part of their three year energy efficiency program filings. This data includes estimates for program costs[36] and program penetration levels for the period 2016 to 2018. Program administrators submit annual data for three sectors (residential, commercial & industrial, and low-income customers), with savings and costs broken out by program and initiative. Based on our review of WMLP operations and Program Administrator data, we include costs and savings data for three energy efficiency measures/programs: residential home measures, which includes lighting and HVAC retrofits, insulation, and other in-home efficiency improvements; residential behavior measures, including education materials and greater use information included on customer bills; and C&I small business retrofits. In May 2017, program administrators published final, evaluated data for these 2016 programs. With respect to residential measures of interest, they found greater energy savings at lower total costs than planned. C&I small business retrofits identified greater savings at a higher total cost. We rely on the 2016 evaluated cost and savings data as proxies for the potential program cost and market penetration for similar programs carried out by the WMLP. Appendix II provides additional detail on our review of these programs and costs.

Table 6 summarizes our inputs, using relevant cost and savings data. To estimate annual WMLP savings, we first identify the market penetration for each program administrator, based on evaluated 2016 savings reported at the initiative level, divided by 2016 evaluated forecasted energy sales at the sector (e.g., residential or C&I) level.[37] We multiply this market penetration rate by forecasted sales.[38] The program measure life is estimated using data for lifetime energy savings divided by net annual savings. This means that for the average residential home installation, energy efficiency savings will last for approximately 9 years, before needing to be renewed or re-implemented. When estimating cumulative savings, we assume that market penetration will remain constant as a proportion of forecasted sales and the WMLP could continue to identify annual savings. Recent studies have identified constant costs even at increasingly higher levels of average net savings as a percent of sales.[39]

Table 6: GHG Emission Reduction Energy Efficiency Costs and Savings

Measure	Levelized Program Cost ($2018/MWh)	Measure Life	Market Penetration	Annual WMLP Savings (MWh)	Cumulative Savings (2030 MWh)
EE Residential Measures	$91.79	9	0.7%	768	6,913
EE Residential Behavior	$68.90	1	1.0%	1,069	1,069
EE C&I Small Business Retrofits	$58.55	12	0.4%	257	2,832
Total				**2,095**	**10,814**

Notes and Sources: Program costs are levelized assuming a 3 percent real discount rate. Program cost data, measure life and market penetration are developed using 2016 evaluated data for Eversource and National Grid reported energy efficiency programs

Distributed Solar

The total capacity for distributed solar resources placed behind the meter will rely on a number of factors, including the size and area of houses and commercial buildings, incentives to customers, and solar incidence. Starting in 2016, Wellesley offered its “More Power to Choose” campaign and offered one-time rebates for the installation of rooftop solar. This resulted in approximately 600 kW of capacity. The WMLP also offers residents a 100 percent credit for net metering of distributed solar power without any cap on total production.

Table 7 compares total residential solar capacity in Wellesley to the capacity to the top five Towns in Middlesex and Norfolk Counties as ranked by existing residential solar capacity. This restriction to Middlesex and Norfolk counties allows for a comparison of towns with comparable housing size and stock and incomes.[40] Average capacity per housing unit ranges from a low of 0.07 kW/unit in Wellesley to a high of 0.33 kW/unit in Concord. The average across all units and capacity in these five Towns is 0.21 kW/unit, which would roughly equal tripling the existing capacity of distributed solar in the Town. For total market potential, we assume that Wellesley could increase its total distributed solar capacity from 0.07 kW/unit to 0.35 kW/unit, which would be comparable to the highest rates observed in nearby markets, with additional room for expansion in future years. Net of existing capacity, this would include an incremental 2,553 kW (2.5 MW) of residential capacity. This is in addition to the already existing 212 kW of distributed solar located on non-residential buildings (e.g., municipal buildings, retail, religious, and education). We do not consider incremental expansion of non-residential distributed solar in this Report. Future policy changes, such as a municipal version of the MA SMART program discussed in Appendix I may provide additional incentives to help meet this goal.

Table 7: Housing and Solar Characteristics, Select Towns in Middlesex and Norfolk County

Town	Total Housing Units	Median Home Value	Owner Occupied (%)	Median Household Income ($2016)	Res Rooftop Cap (kW)
Newton	32,733	$788,500	71%	$127,402	4,251
Lexington	12,161	$769,400	81%	$152,872	3,787
Needham	10,860	$719,600	83%	$139,477	2,992
Concord	7,327	$732,300	77%	$138,661	2,428
Belmont	10,186	$711,200	63%	$114,141	1,648
Wellesley	9,134	$980,400	83%	$171,719	**644**
Massachusetts	2,836,658	$341,000	62%	$70,954	515,440

Notes and Sources: Census data sourced from the 2016 American Community Survey 5-Year Estimates. One-year data estimates are not available for areas with populations less than 65,000. Solar data provided by the Massachusetts CEC Production Tracking System.

We assume that distributed solar would operate with a capacity factor of 15 percent, based on data provided by the National Energy Renewable Laboratory (NREL) PVWatts model, using historical weather data for the Boston region.[41] Together, this would imply an additional 3,351 MWh of potential energy.

For cost data, we rely on the NREL Annual Technology Bulletin (ATB) levelized cost of electricity estimate for distributed residential solar in 2018, which is $171/MWh (unsubsidized) for a system with an average capacity factor of 16 percent (most comparable to the PVWatts estimate) and financing terms consistent with the current market conditions as defined by NREL. NREL estimates that the mid-range estimates will decline by 2.5 percent per year, out to 2050. We assume the same. The following section has additional detail on our choice of levelized cost data.

Supply Side: Procurements of Renewable and Zero Carbon Energy

In contrast to the estimates presented above, there is greater uncertainty surrounding future market potential for new grid-connected renewable capacity. Future additions will depend on market conditions and the outlook for financial returns to project developers, including the cost of capital, the forecasted price of electricity (and natural gas), and the ability to site, build, and interconnect given projects. As described in Section I and Appendix I, Massachusetts and other New England states have implemented several state policies aimed at creating additional supply and demand for new renewable projects.

The market potential for new grid-connected renewable resources also depends, in part, on the risk appetite of new developers and how new projects can be financed. By itself, the WMLP has a limited ability to wholly finance the development of a new project. That is, the WMLP could likely contract for only a portion of any individual resource. To the extent that developers require greater certainty or need a project fully contracted to secure project financing, the WMLP would either need to aggregate its offer and purchase power with other municipal and commercial customers, or the WMLP would need to be a price taker in similar solicitations. As a price taker, the WMLP may seek or receive different terms than other customers signing long-term contracts, based in part on the size of each contract, the timing of negotiation, and current financial outlook. Going forward, the WMLP will need to work with its energy providers and continue to evaluate changes in market conditions and assess the availability of future contract opportunities.

Market Potential

While the purpose of the current analysis is to identify a supply curve of options in the years 2020, 2025 and 2030, it is important to also consider the underlying trend of market costs. In general, the cost of renewables is expected to continue to decline in real terms. This means that a fixed price, long-term contract entered today will (likely) be more expensive than the same contract ten years from now. In this sense, the *timing* of when resources are added to the WMLP matter.

To help frame the discussion of the total market potential for zero carbon resources available by 2030, we need to make several assumptions regarding the availability of future resources. We isolate resource assumptions into a) annual pathways, with known resources in the interconnection queue and a robust history of project development and that can be negotiated with project developers into the future and b) discrete, one time additions of large infrastructure projects for hydropower imports and offshore wind that depend, in part, on regional and State policies.

Annual Contracting

We represent the market potential for new wind and solar resources as an incremental annual quantity. In reality, new contracts and new investment may occur in a “lumpy” or discrete manner, based on actual resource availability. Entering into new contracts may also require additional lead time for negotiation prior to project development, which will influence the exact timing of new contracts.

- ***Onshore Wind***: We assume annual contract quantities of 4,000 MWh per year are available to the WMLP, for a total potential of 40,000 MWh for the period 2020 to 2030. These quantities are assumed incremental to future and/or planned contracts under consideration by WMLP and included in our baseline estimate. This is comparable to, but slightly higher than, the rate at which the WMLP added nearly 26,000 MWh of wind to its portfolio between 2012 and 2020.
- ***Utility Scale or Community Based Solar***: We assume total annual contract quantities of distributed solar or community based solar available to the WMLP of 1,000 MWh per year. This reflects a judgement balancing the expectations for the lower total quantity of solar currently in the interconnection queue and lower expected capacity factor of solar relative to onshore wind, with the recent success of solar projects in the 2015 Massachusetts Clean Energy RFP.

Discrete Market Offers

Under the Massachusetts Clean Energy Standard, utilities can meet compliance obligations through the purchase of clean energy credits (CECs) for energy and environmental attributes from projects that demonstrate net lifecycle GHG emissions that are at least 50 percent below the most efficient natural gas fired generator. The CES includes new resources developed through long-term contracts signed under the Energy Diversity Act under Sections 83C and 83D for new offshore wind and hydropower imports. The CES also includes existing hydropower and nuclear energy. The market potential for offshore wind and hydropower imports depends significantly on the eventual outcome of Section 83C and 83D procurements, while the market potential for nuclear will depend, largely, on the hedging strategy used by existing resources, including an assessment of the contracting options available within Massachusetts through long-term power purchase agreements for energy and/or environmental attributes or the potential for participation in other state programs that are seeking to value and retain the accounting of nuclear energy as part of their long-term climate goals.[42]

We assume, as a general matter, that the WMLP would be able to procure resources in a size proportional to distribution load.[43] While this is an assumption we apply for the purpose of supply curve estimates, we also note that there is little direct information available to develop a more refined estimate. The market availability of these one-time or discrete market purchases represents an important uncertainty for the Town and WMLP, to the extent they are included as an option in future supply plans.

- ***Offshore Wind***: Approximately 15,800 MWh becomes available to the WMLP starting in 2025. This conservatively assumes that the state and distribution utilities meet half of the Section 83C procurement target and achieve 800 MW of new resources. This assumption reflects, in part, the Section 83C program design which authorizes procurement in up to four blocks but requires that submitted project costs continue to decline in each round. We assume that there will be incremental energy beyond the Section 83C procurement quantities, that this is available to other parties, and that the WMLP enters into contract in size proportional to the distribution utility load.

- ***Hydropower***: Similar to offshore wind, we assume that the WMLP would be able to purchase incremental capacity on a high voltage transmission line delivering existing hydropower from Hydro Quebec under a long-term contract under the Section 83D procurement. Given potential delays in the siting and selection of a project, we assume that this contract is available starting with the representative 2025 supply curve, with a total market potential available to the WMLP of 47,265 MWh per year.[44]

- ***Existing Nuclear***: There are currently four nuclear reactors with a cumulative 4,000 MW of capacity operating in New England. This includes the Pilgrim facility, which is slated to retire in 2019, the two Millstone units located in CT, and the 1200 MW Seabrook facility located in southern New Hampshire. Given active evaluation in CT for the potential procurement of energy and environmental attributes with the Millstone units, we assume that total market potential available to the WMLP is based on the output of the Seabrook facility. Between 2014 and 2016, average net generation was approximately 10.2 GWh per year. Using the same ratio of WMLP load to total retail load, we estimate total market potential to the WMLP of approximately 50,000 MWh. Given WMLP's current contract for approximately 40,000 MWh per year, the net remaining for future contracts is approximately 10,000 MWh. We assume that contracted energy, capacity and environmental attributes would be available through the end of 2030.

Not included in this list are incremental energy associated with biomass or landfill gas projects. In 2016, landfill/biogas projects accounted for 12 percent of total RPS compliance, behind only wind and solar. And between 2010 and 2017, the WMLP did maintain a contract for biomass based renewable energy. However, the WMLP decided not to renew this contract given expectations of future wind and clean energy contracts. Further, there are currently no additional landfill gas projects in the ISO-NE interconnection queue. We assume that all existing projects are fully contracted, and that without incremental capacity, assume that there are no incremental options available to the WMLP.

Table 8 summarizes these assumptions, in combination with the total market potential identified for demand side reductions. This illustrates the one-time nature of long-term contracts for large infrastructure projects and the annual addition of known resources. Together, we assume that the total market potential for GHG emission reductions is approximately 132,230 MWh, or approximately 80 percent of the WMLP non-GHG free portfolio.

Table 8: Assumed Market Potential, Demand & Supply Side GHG Emission Reduction Options

GHG Reduction Measure	Annual MWh	Cumulative MWh (2030)
Energy Efficiency and Distributed Solar		
Residential EE - measures	768	6,913
Residential EE - behavior	1,069	1,069
C&I EE - small business retrofit	257	2,832
Distributed Solar	3,351	3,351
Long Term Contracts		
On-shore Wind	4,000	44,000
Utility Scale Solar	1,000	11,000
Existing Hydro Imports (Section 83D)	47,265	47,265
Off-Shore Wind (Section 83C)	15,800	15,800
Existing Nuclear	10,000	10,000
Total		**142,230**

Notes: Assumes beginning of year contracts, starting in 2020. Cumulative 2030 totals include 11 contract years.

Market Prices

To estimate the potential costs to the WMLP to enter into long-term contracts for these resources, we use publicly available estimates for the levelized cost of electricity (LCOE) for renewable technologies.

The levelized cost of electricity (LCOE) is a widely published – and widely analyzed – metric that provides a snapshot estimate of costs across technologies. The LCOE expresses the total cost to build, own and operate an electric generation resource on a levelized or annual basis over the assumed economic life of the asset, accounting for total capital costs, fixed operations and maintenance costs, variable costs, taxes, depreciation, and the required return on capital for investors. The LCOE compares these levelized costs to expected annual electricity generation, which varies by technology and the assumed or average capacity factor. In this sense, the LCOE is best thought of as an "all-in" cost of electricity over an investors' expected time horizon.

It is important to note that the LCOE is just one metric used to compare projects – with a focus on total costs and required returns to investors. The LCOE considers the total energy provided by each resource, but does not quantify or include an assessment regarding the value of that energy to the broader system or the suite of characteristics that are important when considering a broader portfolio optimization. For example, the LCOE does not differentiate between dispatchable or non-dispatchable resources or consider the ability to provide ancillary services or meet other reliability criteria.

Actual contract costs may differ for several reasons, based on the cost of capital, actual capital costs (including potential transmission or interconnection costs), economic life of the asset (which may vary from the technical or productive lifetime) and the actual performance of the unit. Energy only or energy/environmental contract values may also be lower than the total LCOE. However, as described in the following section, these contracts would also offer less benefits to the WMLP in the form of avoided costs.

Key Assumption #3:

Levelized Cost of Electricity (LCOE) represents the price for long-term contracts of energy, capacity and environmental attributes (RECs).

We rely on national average cost data provided by the National Renewable Energy Laboratory (NREL) Annual Technology Bulletin (ATB), for projects of similar resource potential based on historical capacity factors for similar resources in New England. We rely on the default assumptions contained in the NREL ATB with respect to the current market conditions for the cost of capital and project financing, and do not consider recent changes in the tax code or the impact of the investment tax credit or production tax credits. [45] While LCOE values may not perfectly approximate contract prices, it is important to note that over the past decade, LCOE and average PPA prices for renewable resources have declined in a similar fashion, most rapidly in early years and leveling off in more recent years.

Our use of the NREL ATB estimates also allows us to capture the future decline of resources, based on changes in overnight capital costs. Going forward, costs for renewables should be expected to continue their recent decline, albeit at lower rates, as economies of scale and learning within the supply chain and other technological advancements in efficiency reach maturity.

Together, the NREL ATB allows us to use publicly available cost estimates for projects of similar capacity and resource potential that is available in the Northeast, and allows us to capture future cost declines in these resources over time.[46] Table 9 provides our assumptions regarding the costs for these projects and the compound annual growth rate (CAGR) that expresses these cost declines on an average annual basis. We do not consider the incremental costs associated with transmission interconnection for these resources, with two exceptions. The NREL ATB estimates include off-shore transmission costs for off-shore wind. And for existing hydropower resources, we assume an additional $13.75/MWh for incremental transmission costs.[47]

There is little to no public data available on the potential contract costs for existing nuclear resources. The price will depend, in part, on nuclear units expectations for energy and capacity market revenues, the potential for additional revenues for the environmental attributes of zero carbon energy generation. Contract prices will depend, as well, on whether or not these revenue streams provide a sufficient return to merchant owners, given market risk and potential going forward capital costs for fixed operations and maintenance expenses and other necessary capital improvement investments.

As a starting point, we assume an average proxy price of $60/MWh in $2018 with low and high price sensitivities at $54/MWh and $66/MWh, respectively. Our estimate offers an illustrative proxy price consistent with current market conditions in other regions, and offers the opportunity to directly compare existing nuclear contracts with the cost for other new resources. We base our estimate on several sources including operating costs, expected market revenues, and regulatory determinations for the value of environmental attributes.[48]

Table 9: Levelized Cost of Electricity ($2018/MWh) for In-Service 2018

Technology	Cost ($2018/MWh)	CAGR	Capacity Factor/Notes	Term
Onshore Wind				
Low	$76	-2.42%		
Mid	$82	-1.30%	24% (TRG 8)	20 Years
High	$88	0.00%		
Utility/Community Solar				
Low	$81	-2.69%		
Mid	$88	-1.48%	14%	20 Years
High	$113	0.00%		
Offshore Wind				
Low	$100	-2.31%	45% (Fixed Bottom Resources, TRG1) Includes offshore transmission costs	20 years
Mid	$107	-1.64%		
High	$114	0.00%		
Existing Hydropower				
Low	$73	-1.49%	Existing Resources (Non-powered dams "NPD"), with capacity greater than 10 MW	20 Years
Mid	$76	0.00%		
High	$76	0.00%		
Distributed Residential Solar				
Low	$150	-3.76%		
Mid	$171	-3.51%	16.1% (Fixed Tilt Rooftop System)	20 Years
High	$190	0.00%		
Existing Nuclear				
Low	$54	0.00%	Based on current operating expenses, estimated revenues, and value of zero emission credits	11 Years
Mid	$60	0.00%		
High	$66	0.00%		

Notes and Sources: Data provided by NREL ATB (2017), based on current market conditions for project financing. Model assumes a 4.4 percent cost of debt, 9.5 percent return on equity, and a capital structure of 60% debt, 40% equity. NREL estimates are in $2015 and converted to $2018 assuming inflation of 2.2 percent per year. Project term is 20 years for each resource.

IV. An Evaluation of the Supply Curve of Options Available to Reduce GHG Emissions

To assist the WMLP in an evaluation and comparison of these potential GHG emission reduction options, in this section we develop a supply curve of options using the market potential and cost assumptions developed in Section III. In each year, we evaluate the potential CO_2 reduction levels and the net costs, after considering wholesale cost savings through avoided energy, capacity and transmission purchases. Because different reduction options face different program terms and lifetimes, we annualize each measure in real (constant 2018 dollar) terms over the life of the program using a 3 percent real discount rate.[49] When necessary, we assume an annual inflation of 2.2 percent, consistent with the long-term outlook for the consumer price index from 4Q 2017 as reported by the Philadelphia Federal Reserve Survey of Professional Forecasters. We then compare each set of options on a \$2018/ton CO_2 and a \$2018/MWh basis.

This comparison on a normalized basis is important, given the potential uncertainty in the future market potential presented in Table 9 above. By normalizing costs, one can more directly compare the net costs across different GHG reduction options, and develop a relative ranking of projects within any given year. This ranking can help define priority projects as part of a decarbonization pathway and offer one method to quantify potential costs at different levels of market resource potential.

In this section, we first present our assumptions related to the avoided purchases of energy, capacity and transmission services from the wholesale market. We then present our results, combining cost data from Section III and benefits assumptions developed here.

Potential wholesale/distribution cost savings

Energy procurements through fixed long-term contracts or reductions in energy use from energy efficiency or distributed resources will reduce total WMLP purchases for energy, capacity and transmission services from the wholesale regional energy market. These avoided purchases represent a benefit to WMLP customers. The value of these benefits will depend on the generation profile and capacity factor of each resource. Resources that can reduce demand or provide power during peak periods will offset higher energy prices or reduce total capacity requirements.[50]

Future estimates of energy and capacity prices will depend on several factors, including the price of delivered natural gas to the region, the effects of state policy described above, individual generator additions and retirements, weather, and system performance. Over the long run, capacity prices will reflect changes in energy market revenues and expectations of energy prices. To this end, we rely on internally consistent forecasts of both energy and capacity, and we estimate these potential benefits using publicly available data provided by ISO-NE that were developed in support of the February 2018 forward capacity auction.[51]

Avoided Energy Benefits: We rely on the hourly locational marginal price (LMP) forecast developed by Concentric Energy Advisors.[52] Hourly LMP data is provided for the period 2021 to 2040 (in $2021).[53] We convert energy prices to constant $2018 using the 2 percent inflation factor assumed in their analysis. For the period 2018 to 2021, we rely on the average forecasted energy price included in the most recent WMLP five year financial plan.

Because detailed load shape data for each GHG reduction measure is not available, we quantify avoided energy benefits using an annual average price series. This represents a potentially conservative estimate that may tend to understate potential benefits, at least for those resources that reduce energy demand primarily during peak periods.

Avoided Capacity Benefits: The Concentric study estimated that the net CONE used in the FCA #12 demand curve would be $8.70/kW-mo ($2021). As a starting point, we rely on this value for the long-term outlook of capacity prices, converted to $2018. We assume that capacity prices remain constant in real terms, or put another way, that they increase annually at the rate of inflation. FCA#12 was held on February 5, 2018 for capacity delivered in June 2021 through May 2022, with the final auction closing at a cost of $4.631/kW-mo. This is lower than the cleared capacity prices in prior years 2018-2020 of $9.55/kW-mo, $7.03/kW-mo and $5.30/kW-mo, respectively. We rely on actual cleared prices (adjusted to real $2018) for the period 2018-2021.

Future capacity prices will depend on the shape of the FCA demand curve, the most recent estimate for the net CONE, and the total quantity of resources that bid into the capacity market. In 2017, an Analysis Group study estimated capacity market outcomes in 2025 and 2030 under six scenarios as part of an analysis prepared for the NEPOOL planning process.[54] These scenarios modeled varying levels of thermal retirements, imports and renewable resource participation in regional markets. That study further considered 6 sensitivities, for varying levels of resource additions and market mitigation (MOPR) treatment of imports and renewables. Across these various model runs, modeled clearing prices in 2025 ranged from a minimum of 55 percent of net CONE to 114 percent of the net CONE, with a median of 88 percent. Results were similar for 2030. We assume that future capacity prices will clear at 88 percent of net CONE, consistent with that analysis.

For each GHG emission reduction measure, we quantify annual savings from a reduction in peak demand. For energy efficiency measures, we rely on the reported program administrator data for the ratio of annual energy to peak summer capacity savings. We assume that long-term contracts include a capacity supply obligation, in addition to energy and environmental attributes. This is consistent with our assumption that the LCOE is representative of the long-term contract price. To estimate the value of these capacity supply obligations, we rely on the ISO-NE estimate for the quantity of generation that is assumed to be deliverable during summer peak hours in transmission reliability analyses: 5% for onshore wind; 20% for offshore wind; 26% for solar; and 100% for (firm) hydro resources.[55] Pairing these grid-connected renewables to pumped storage or battery storage may increase the ability to more consistently provide power during peak demand periods. This would provide additional value to these resources through greater avoided capacity benefits. We similarly assume a 100% deliverability factor for existing nuclear resources. This is consistent with recent modeling work developed in support of the ISO-NE FCM pay-for-performance mechanism.[56]

Avoided Transmission Benefits: A reduction in monthly coincident peak demand will also reduce the WMLP's payments for Regional Network Service (RNS). We rely on the annual average RNS price ($/kW-mo) based on the WMLP 5-year financial forecast. After 2022, we assume that RNS prices continue to escalate at the forecasted real compound annual growth rate over the period 2018 to 2022. RNS payments are charged on a monthly basis. We assume monthly reductions in coincident peak demand consistent with the planning assumptions above. To the extent that resources offer a greater reduction in peak demand during winter months, our use of an annual average based on summer reliability benefits would tend to understate potential benefits. We assume that only behind the meter measures (e.g., energy efficiency and distributed solar) that reduce coincident peak demand reduce or avoid future RNS payments.

Future changes in electricity demand may also affect the WMLP distribution network. In the short term, reductions in system load through demand side measures or through an increase in distributed PV resources may defer or delay future capital expenditures. Recent studies have found that this value depends significantly on the location of potential reliability violations and the physical distance between reliability challenges and distributed resources.[57] To the extent that the WMLP already has a robust distribution capital improvement plan underway, deferred distribution expenses over the near-term are expected to be minor. In contrast, over the long-term, changes related to a potential increase in load from electric vehicles or the electrification of residential heat sources may increase pressure on the distribution system, while advances in energy storage may provide a greater ability to defer a second iteration of a 30 year distribution capital plan.

Results

Taken together, we evaluate the net costs and avoided emission for each of our supply curve options, under estimates of low-,mid-,and high- price scenarios, in each year of the period 2018 to 2020. Figures 7 and 8 provide examples of disaggregated model results for a long-term onshore wind contract signed at the mid- price estimate in the year 2020 and 2030, while Figure 9 shows similar data for C&I energy efficiency installed in 2020, including the additional benefit for avoided transmission costs associated with regional network services. The solid flat line illustrates the cost of the contract, which is constant in real terms (or increasing with inflation in each year) over the contract term. In contrast, total benefits increase each year, as the real price of energy increases. The difference between the stacked bars and the levelized cost of electricity is the net benefit (cost) to ratepayers. To develop the supply curve in each program year, we take the net present value of this net benefit (cost). We then translate this net present value into equivalent annual payments over the full term of the project. Costs are expressed in $2018 starting in the first year of the contract.

Figure 7: Annual Costs and Avoided Benefits ($/MWh), Onshore Wind, Installed 2020

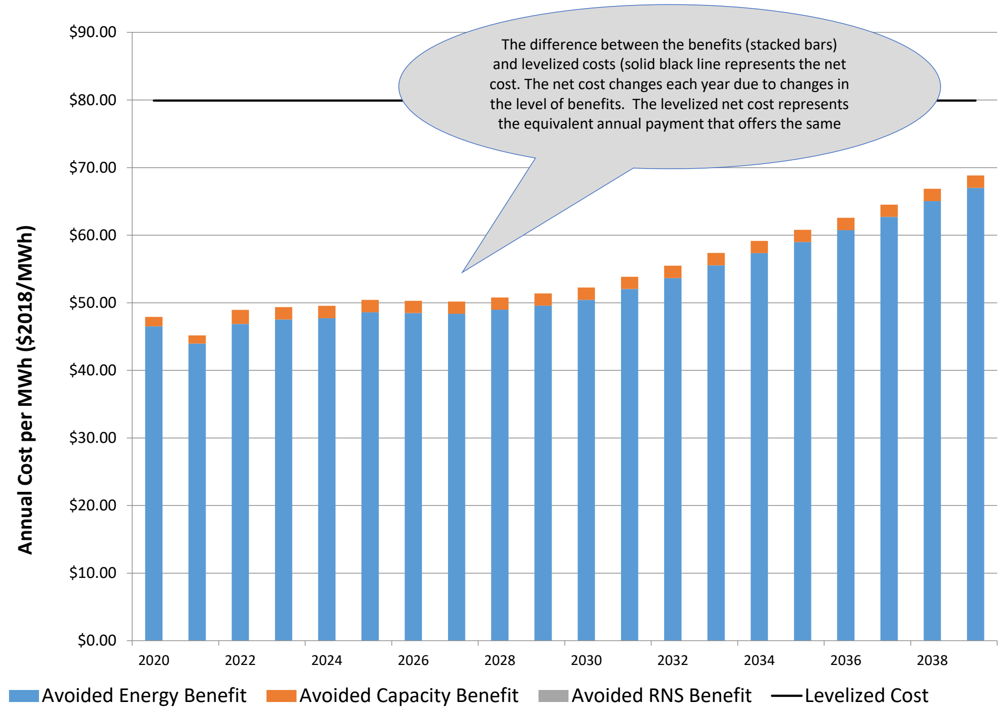


Figure 8: Annual Costs and Avoided Benefits ($/MWh), Onshore Wind, Installed 2030

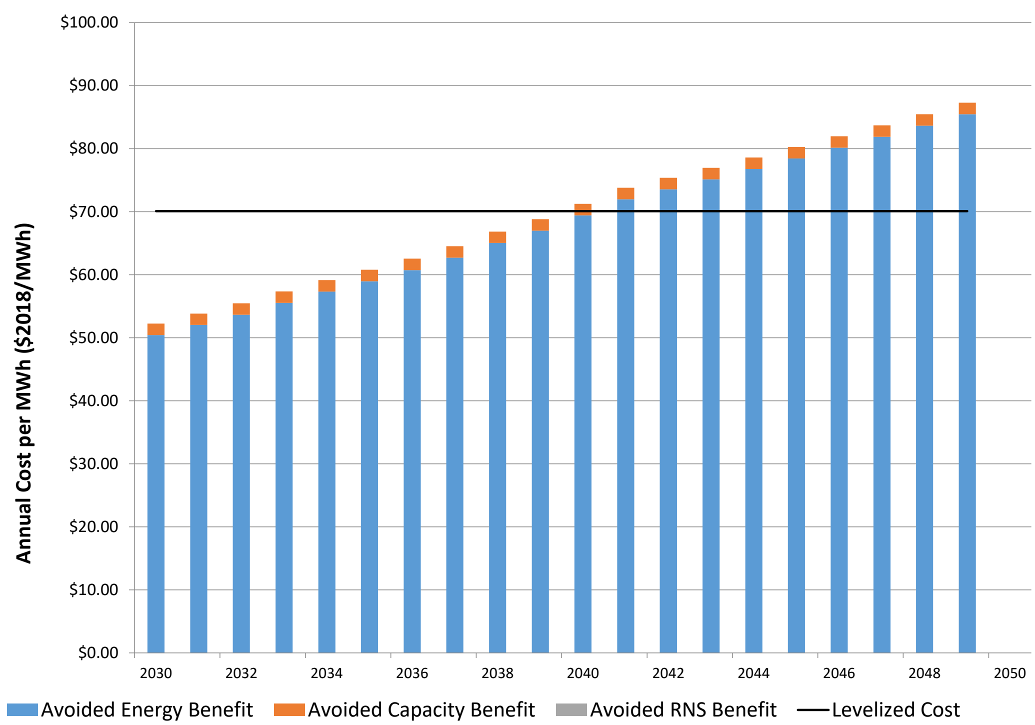
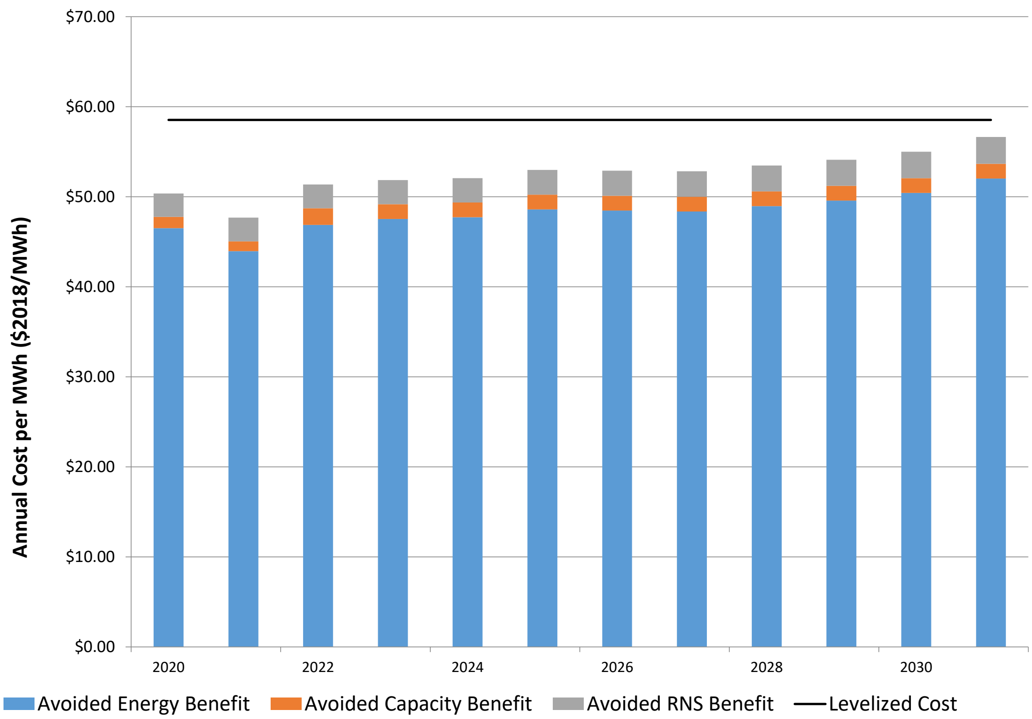


Figure9: Annual Costs and Avoided Benefits ($/MWh), EE C&I Retrofits, Installed 2020



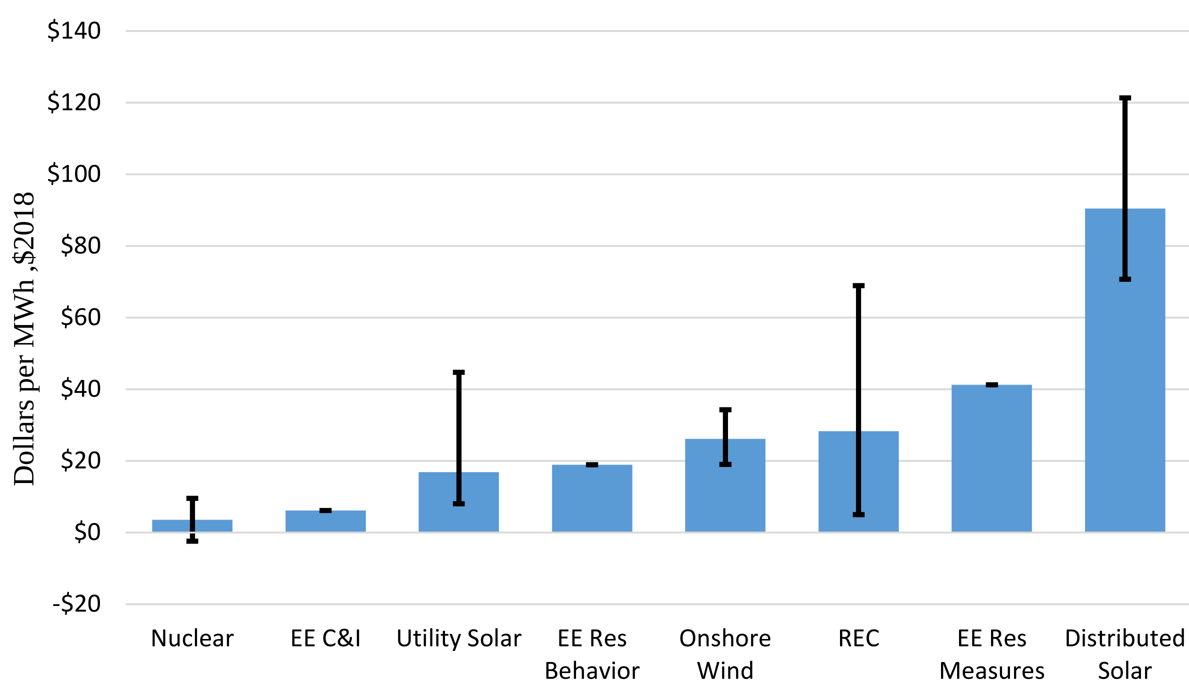
Figures 10 to 12 present the supply curves for the years 2020, 2025 and 2030. In each of the representative years, we sort the supply curve from lowest to highest cost, including REC purchases at the assumed mid-point estimate. Error bars indicate the range of uncertainty, given our estimates for low and high costs and the rate of cost changes for each technology in each year.

As illustrated here, all measures would require additional or net costs to WMLP ratepayers in the near-term, while some select measures providing net benefits (negative costs) starting in the year 2030. Many reports have noted that the recent levelized cost of electricity for wind and solar is on par or potentially less expensive than the levelized cost of electricity from *new* natural gas plants. These net costs, however, illustrate that there is still an incremental cost relative to the power delivered from *existing* resources within the ISO-NE grid. And while not quantified here, this suggests that contracts with existing low or no GHG emission resources already sited within the ISO-NE grid (such as existing nuclear or existing hydro facilities) would likely offer the lowest cost option with potential net benefits to WMLP ratepayers.

In contrast, several new incremental measures are consistently lower cost relative to the purchase of existing Class I RECs at an assumed mid-point estimate. These include C&I energy efficiency, residential behavior energy efficiency, utility/community scale solar, and onshore wind contracts. Notably, utility/community scale solar projects appear to be among the most cost-effective long-term contracting options. This is consistent with the recent results announced by the MA distribution utilities as part of its 2015 "Clean Energy" RFP.[58] The final selections in that RFP included 9 solar projects with a combined capacity of 264 MW and 1 wind project of 126 MW. However, these results also come with the greatest price uncertainty in future costs, as illustrated by the range of low/high error bars. Uncertainty will be driven by a number of factors, including material costs, labor costs, and technological improvement. (The price estimates developed by the NREL ATB do not include tax incentives or the impact of recently announced tariff programs. These short term impacts may be less likely to affect cost estimates for the year 2030 and beyond.) And by 2025, if hydro imports and offshore wind are available at assumed prices, these may also be more cost effective than the purchase of annual existing Class I RECs.

Distributed solar and in-home residential energy efficiency measures are among the most expensive options included. It is important to note that our analysis focuses narrowly on costs associated with electricity sector benefits, and that these options may have additional value not quantified here. For example, distributed solar may delay or avoid distribution related capital expenditures or help meet growing customer demand for more control of their own energy supply. And residential energy efficiency measures will provide additional benefits through reduced consumption of natural gas, oil and water; for example, in the initial three year plan filed with the MA DPU, distribution utility program administrators estimated that electricity related benefits for energy, capacity, and transmission services accounted for only 25 percent of total resource value to ratepayers.

Figure 0: Levelized Net Cost per MWh in 2020, $2018



Notes and Sources: Analysis Group analysis. Error bars represent low/high estimates of net costs, given uncertainty in future costs technology costs. See Section III.

Figure 1: Levelized Net Cost per MWh in 2025, $2018

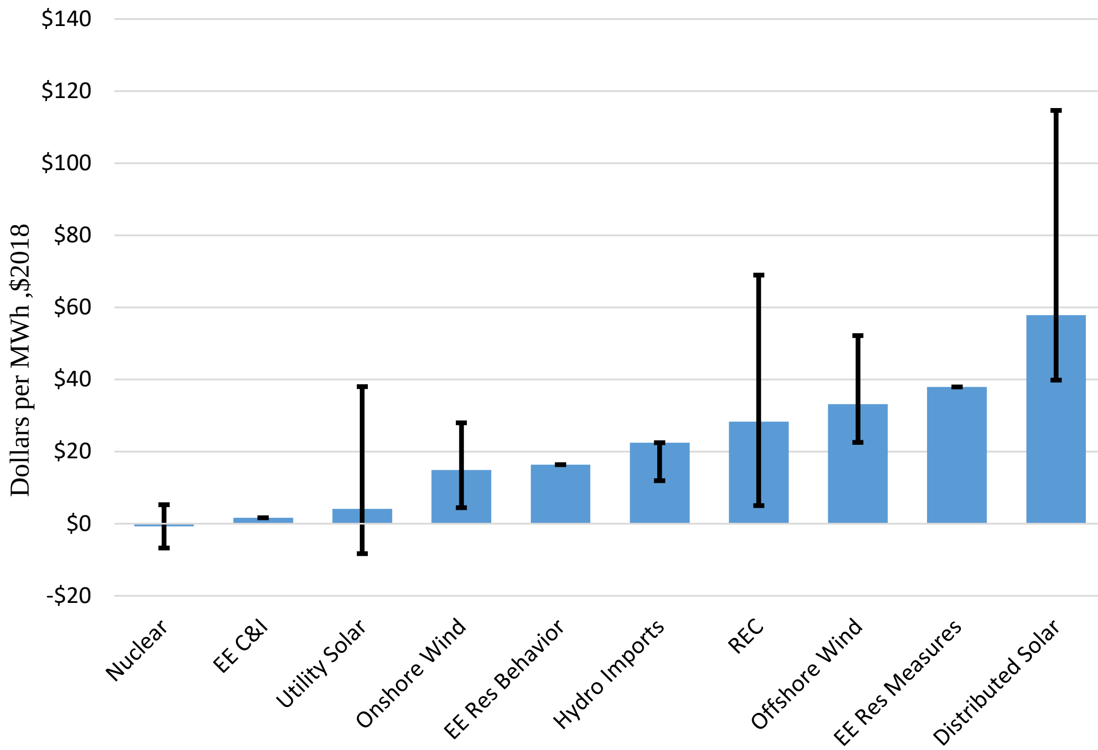
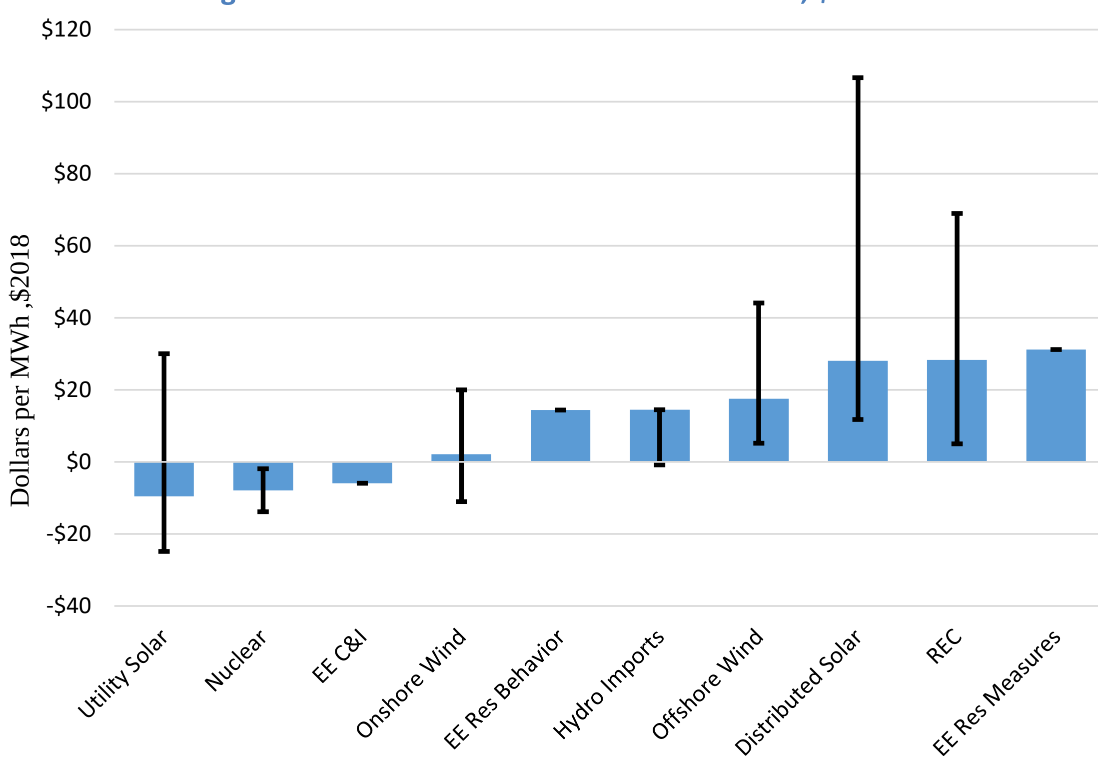


Figure 2: Levelized Net Cost Per MWh in 2030, $2018



Figures 11 thru 13 also highlight that the net cost per MWh is expected to decline over time, as benefits increase from avoided energy purchases and costs for long-term contracts decline. In 2020 and 2025, all measures present a net cost to WMLP ratepayers, but by 2030, investments in utility/community scale solar and C&I energy efficiency will provide net savings to ratepayers. Table 10 provides the same data as Figures 11 thru 13, with each measure expressed in $2018 per MWh, with results for the representative years 2040 and 2050 included for comparison purposes. (Annualized net costs for 2040 and 2050 are truncated at the year 2050 and do not include costs or benefits after this time.)

Table 10: Net Cost ($2018 per MWh) for Select GHG Emission Reduction Measures

GHG Measure	2020	2025	2030	2040	2050
Annual Measures					
Renewable Energy Credit	$28.30	$28.30	$28.30	$28.30	$28.30
Demand Side Measures					
EE Res Measures	$41.23	$37.93	$31.20	$11.45	$0.34
EE Res Behavior	$18.95	$16.39	$14.39	-$5.00	-$23.32
EE C&I	$6.14	$1.64	-$5.98	-$24.70	-$34.27
Distributed Solar	$90.42	$57.81	$28.08	-$17.14	-$49.79
Supply Side Measures					
Onshore Wind	$26.17	$14.90	$2.14	-$18.33	-$35.18
Utility Solar	$16.86	$4.10	-$9.58	-$31.60	-$49.65
Offshore Wind		$33.15	$17.55	-$7.74	-$28.42
Hydro Imports		$22.46	$14.44	$2.56	-$6.75
Nuclear	$3.56	-$0.76	-$7.89	-$27.11	-$36.42

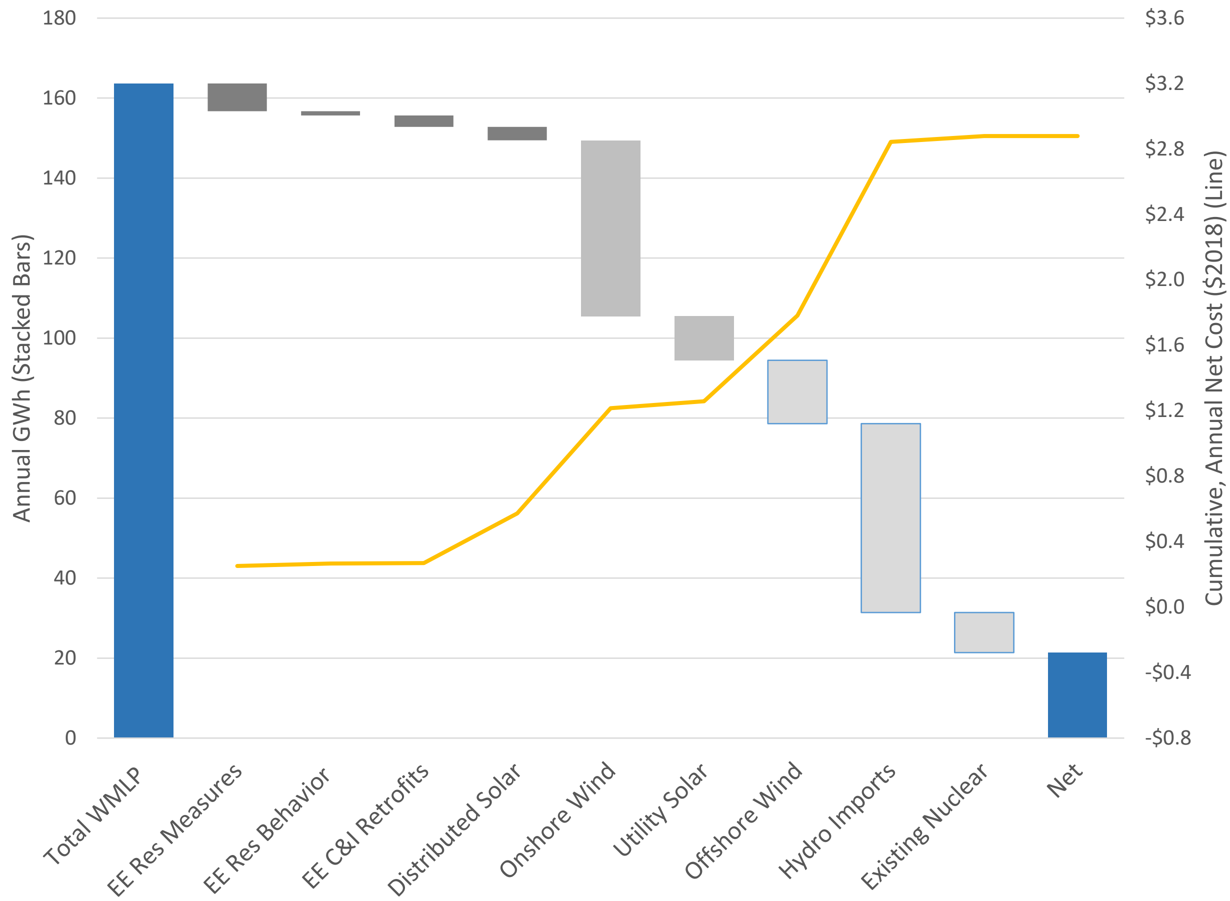
Notes: Annualized net costs for 2040 and 2050 are truncated at the year 2050 and do not include costs or benefits after this time.

However, future declines in price also come with greater uncertainty. As illustrated in the supply curves, the range of potential estimates grows over time, particularly for distributed and utility/community based solar. When evaluating future pathways, it is important to consider these trends of lower costs and greater uncertainty. Long-term contracts signed today will necessarily require a tradeoff between certainty and flexibility. Price certainty and GHG emission reduction goals in the near-term should be balanced against mid-term priorities, with an eye towards actions that may lock in a solution today that prevents or limits greater options in the future. For example, if the WMLP fully contracted for its load today, it may not be able to add additional base load resources from hydro or offshore wind in the future. Similarly, it may not be able to capitalize on falling prices for renewables, or integrate future market changes that promote or incentivize the use of storage or other programs that shift load and allow for greater alignment between renewable production and customer demand.

Combined Costs for all Measures: Illustrative Pathway to 100 percent GHG Reduction

In this section we provide an illustrative demonstration of the total cost and the total GHG emission reduction impact of a set of these measures. We quantify the total cost of all measures presented in Sections II and III, together. We include all direct measures affecting the WMLP portfolio, with and without additional REC purchases to meet a hypothetical 100 percent target. As discussed in Section III, there are other important considerations to achieving a GHG emission reduction target other than cost. This study provides just one input into that broader discussion. With these caveats in hand, Tables 11 and 12 quantify the total emissions reduction and the total net cost to ratepayers based on the assumptions for the total quantity of available GHG emission reductions discussed in Section IV. Together, these measures could provide reductions of up to 80 percent by 2030 at a net cost to ratepayers of an additional $2.9 million per year, or approximately $11.3 per household per month. With additional RECs to meet a 100 percent target, the total cost would rise to approximately $3.5 million per year or $13.8 per household per month. As discussed throughout this Report, there is considerable uncertainty for the market potential of various resources, the associated costs, or the ability to fully execute contracts. As an upper bound, total compliance with a 100 percent goal could be met with annual costs of $11 million per year, assuming REC prices under a constrained market, equal to the Alternative Compliance Payment rate. This would be equivalent to a monthly bill increase of approximately $44 per household per month. Figure 13 illustrates this same data alongside total reductions in energy use for each measure. Measures are presented in the same order as described in the Report text above; the order of measures and cumulative costs does not represent a recommendation or a normative statement regarding the value or sequencing of potential measures that may be considered by the WMLP.

Figure 3: Cumulative GHG Emission Reductions and Net Costs in 2030 ($2018)



Notes and Sources: Analysis Group analysis. Costs represent midpoint estimates. GHG reduction measures are presented in the order described within this Report, and do not represent a recommendation or conclusion regarding a potential GHG emission reduction pathway.

Table 11: Cumulative GHG Emission Reductions, Portfolio Measures

Total Annual GHG Emission Reductions (tons CO_2)				MWh		
Measure	**2020**	**2025**	**2030**	**2020**	**2025**	**2030**
Energy Efficiency - Residential Measures	323	1,940	2,910	768	4,609	6,913
Energy Efficiency - Residential Behavior	450	450	450	1,069	1,069	1,069
Energy Efficiency - C&I Retrofits	110	660	1,211	261	1,569	2,876
Distributed Solar	1,411	1,411	1,411	3,351	3,351	3,351
Long Term Wind	1,684	10,104	18,524	4,000	24,000	44,000
Long Term Utility/Community Solar	421	2,526	4,631	1,000	6,000	11,000
Offshore Wind	0	6,652	6,652	0	15,800	15,800
Existing Hydro Imports	0	19,899	19,899	0	47,265	47,265
Existing Nuclear	4,210	4,210	4,210	10,000	10,000	10,000
Total	**8,609**	**47,852**	**59,897**	**20,450**	**113,662**	**142,274**
Percent of 2018 Non-GHG Total	*12%*	*69%*	*87%*	*12%*	*69%*	*87%*
Required RECs for a 100 percent goal				**143,194**	**49,982**	**21,370**

Table 12: Cumulative Annual Net Costs ($2018) for Market Potential of GHG Emission Reductions (Table 11)

Total Annual Net Costs ($2018)			
Measure	**2020**	**2025**	**2030**
Energy Efficiency - Residential Measures	$31,670	$183,014	$251,629
Energy Efficiency - Residential Behavior	$20,254	$17,522	$15,381
Energy Efficiency - C&I Retrofits	$1,605	$6,307	$2,950
Distributed Solar	$302,985	$302,985	$302,985
Long Term Wind	$104,693	$494,451	$642,685
Long Term Utility/Community Solar	$16,856	$62,428	$42,672
Offshore Wind	$0	$523,784	$523,784
Existing Hydro Imports	$0	$1,061,340	$1,061,340
Existing Nuclear	$35,607	$35,607	$35,607
Total	**$513,670**	**$2,687,436**	**$2,879,032**
With Additional RECs	*$4,145,478*	*$1,446,969*	*$618,665*
Total for a 100 percent goal	**$4,659,148**	**$4,134,405**	**$3,497,698**

Representative Monthly Residential Bill Impacts ($2018 per Month) *For Customer Using 975 kWh per Month*			
Measure	**2020**	**2025**	**2030**
Energy Efficiency - Residential Measures	$0.12	$0.72	$0.99
Energy Efficiency - Residential Behavior	$0.08	$0.07	$0.06
Energy Efficiency - C&I Retrofits	$0.01	$0.02	$0.01
Distributed Solar	$1.19	$1.19	$1.19
Long Term Wind	$0.41	$1.94	$2.52
Long Term Utility/Community Solar	$0.07	$0.25	$0.17
Offshore Wind	$0.00	$2.06	$2.06
Existing Hydro Imports	$0.00	$4.17	$4.17
Existing Nuclear	$0.14	$0.14	$0.14
Total	**$2.02**	**$10.56**	**$11.31**
Percent	**1.5%**	**7.7%**	**8.3%**
With Additional RECs	$18.30	$16.24	$13.74
Total for a 100 percent goal	**13.4%**	**11.9%**	**10.0%**

Notes and Sources: Analysis Group analysis. Cumulative net costs include costs for programs installed in each year. By 2030, some program measures include negative net costs (see Figures 11-13), with a corresponding reduction to cumulative costs.

V. Developing a Pathway towards GHG Emission Reductions: Additional Considerations

There exists an ongoing and important debate between the costs and feasibility of different decarbonization pathways for the electric grid as a whole. Studies that tend to optimize pathways based on costs or feasibility, tend to find that a diverse mix of low and zero carbon resources offers the best opportunity to meet GHG reductions of 80 to 100 percent.[59] In contrast, other studies ask a different question; namely, whether or not those same GHG reductions can be met through a narrow selection of renewable technologies only. Framed that way, studies find that a renewable only portfolio is feasible if it is accompanied by a large expansion of the transmission grid, a substantial increase in total storage capability, or both. That debate centers around the electric grid as a whole and may not apply to the individual actions taken by a single community in isolation. However, it helps pose the set of tradeoffs that the WMLP could or may consider as others in the Region undertake similar actions.

In developing a supply curve of GHG emission reduction options, we rely on the net cost as our metric of evaluation. This focus allows for initial assessment between GHG emission reduction options. However, a broader set of factors would likely need to be considered when developing a portfolio of reduction measures that can be used to meet a Town goal. Collectively, the combination of GHG emission reduction measures would pose important questions and tradeoffs associated with system reliability, revenue adequacy, potential rate impacts between customers, and the impact to WMLP operations, with each option or set of options providing a different mix of flexibility or certainty along dimensions of interest.

While it is beyond the scope of this report to quantify the potential cost impact of increased volatility or uncertainty to the WMLP, Figure 14 does highlight some of the potential tradeoffs between annual measures and longer-term strategies. As a starting point, note that an over-reliance on any one GHG emission reduction option would tend to increase risk through reduced flexibility. For example, an over-reliance on retiring existing Class I REC purchases could expose the WMLP to considerable budget uncertainty, since the price of RECs will change year to year. Similarly, an over-reliance on long-term contracts would lead to a mismatch between generation and WMLP demand and require the WMLP to be exposed to wholesale market purchases and sales on a more frequent basis. These transactions could lead to either net costs or benefits over time, but may create increased uncertainty and volatility with respect to the WMLP budget and potential costs to consumers. Similarly, with fully-contracted load, the WMLP would have less flexibility to pursue new or emerging technologies that are potentially better or lower cost over time, and also have less ability to take advantage of falling renewable prices and potentially lower-cost programs in the future. In contrast, annual purchases of RECs would allow the WMLP to potentially phase in additional contracts as conditions change. These tradeoffs point out that annual contracting or longer-term measures are not either – or decisions, but rather, can be combined in various combinations to provide complementary functions and increase the value of a portfolio to the benefit of the WMLP and its ratepayers along non-price dimensions.

Figure 4: Additional Considerations of GHG Reduction Measures

Annual REC Purchases

- **Can be implemented immediately by the WMLP,** with minimal dependence on other market actors
- Offers the greatest flexibility with respect to timing and quantity of purchases to meet Town-wide goals
- Provides **little to no additional benefits to WMLP ratepayers,** through avoided costs
- **Supports existing State programs** and existing resources
- Annual price and quantity driven by market changes; changes in annual prices **increases budget volatility**, with potential cost savings or cost increases
- Provides WMLP with **greatest operational flexibility** and ability to meet system reliability metrics through existing operations
- **Reduces potential lock-in of options** and offers potential for greater electrification **and ability to scale** with other Town-side GHG goals

Long-Term Investments and Programs

- **Long-term contracts for resources** provides price certainty and may offer benefits to ratepayers through avoided energy and capacity purchases
- **Energy efficiency and distributed resource programs** can be implemented by the WMLP directly and phased in over time; likely to provide additional benefits to WMLP ratepayers through avoided costs of energy, capacity, transmission, distribution, and provide non-energy benefits to gas and water use and potential health costs
- **Market potential for large infrastructure projects is highly uncertain** and depends on a variety of actors
- Significant hedging or long-term contracts may increase budget volatility and uncertainty, with **increased need to buy and sell power within the Real-Time market** to meet system demand
- **WMLP is a price taker** in current market and ability to enter into long-term contracts will **depend on ability to aggregate demand** of other customers

VI. Conclusions

This study represents a scoping exercise that considers, based on current information and market expectations, the suite of GHG emission reduction measures that would likely be available to the WMLP in the near-term. It is designed to provide the WMLP and its Board with data, information and insights that may be used to evaluate potential strategies for future GHG emission reductions, and to inform considerations related to the timing, measure, and scope of Wellesley's GHG reduction efforts. To inform near-term actions, the Report primarily focuses on measures that build from recent WMLP experience with demand side reductions in energy, supply side procurement of renewable energy, and the developing market for distributed energy resources.

In particular, we review two types of strategies whereby WMLP could reduce the effective level of GHG emissions associated with the Town's use of electricity. The first option involves the ***annual*** and ongoing purchase of REC/CEC from a secondary market for the environmental attributes associated with energy generated by existing resources in New England.[60] The second option involves ***longer-term investments*** in energy efficiency and the procurement of energy (and the associated environmental attributes) from low- or zero-carbon renewable, hydropower, and existing nuclear resources.

As described in this Report, these alternatives are not an either/or decision; rather, they represent potentially complementary options to reducing the effective GHG intensity of the electricity resources WMLP uses to meet customer demands for electricity. Different options necessarily involve tradeoffs and different types of benefits to the WMLP with respect to net cost to ratepayers, budget and price certainty, and differing levels of flexibility to adjust as program needs evolve over time.

Cumulatively, we find that by 2030, the market potential for resources potentially available to the WMLP could provide up to 142,000 MWh of qualifying clean energy, approximately 87 percent of the remaining WMLP portfolio needs. Large infrastructure projects and one-time contracts with new hydropower imports, offshore wind, or existing nuclear generation account for more than 70,000 MWh of low-carbon energy or roughly 50 percent of the total identified WMLP market potential. In contrast, projects directly within WMLP's control, including energy efficiency and distributed solar, account for 10 percent of the total market potential, while long-term contracts with onshore wind and solar account for the remaining 40 percent.

Procurement of all long-term carbon-reduction measures effecting WMLP supply and demand would require annualized net costs to WMLP consumers of $2.9 million in 2030 ($2018) and would rely on significant reductions from offshore wind, existing nuclear, and hydropower imports. Additional REC purchases could be used to meet a full reduction of GHG emissions. Under this scenario, total annualized net costs would approach $3.5 in 2030. The WMLP could also meet GHG emission reductions targets solely through the annual purchase and retirement of a sufficient number of Class I RECs. Using RECs alone, total costs in the mid-price case would be $4.6 million per year (with a potential range from $0.8 million per year to $11.3 million per year), resulting in a 3.3 percent rate increase (with a potential range of 2.3 percent to 32.4 percent).

Developing a supply curve of GHG emission reduction measures necessarily requires development of market and technological forecasts, and the application of professional judgement about the evolution of the electricity sector on a going-forward basis. We thus develop an initial scoping of near-term reductions that compares different reduction measures on a consistent and comparable basis, using transparent assumptions and an easily-identified analytic approach. Through this focus on transparency, the study provides actionable data and insights to the WMLP Board in a readily-accessible form that can be re-evaluated and updated as system conditions continue to evolve in the future.

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Appendix I: Regional Policies

In 2017, RGGI states approved a new system-wide cap of 75 million short tons of CO_2 in 2021, declining by 2.275 percent per year out to 2030. This new declining cap represents a 30 percent reduction from 2020 levels and at currently forecasted levels of generation, implies a system-wide average annual emission rate of approximately 405 lbs of CO_2 per MWh of generation. This regional rate would be almost 50 percent lower than the most recent value estimated by ISO-NE of 747 lbs of CO_2 per MWh.[61]

Similarly, in August 2017, the Massachusetts Executive Office of Environmental Affairs (EOEA) and DOER published regulation 310 CMR 7.74, which also sets an annually declining emission limit for thermal generators within the State. This declining emission cap starts at 8.95 million metric tons of CO2 in 2018, declining to 1.8 million metric tons by 2050. Based on expected generation totals, this emission cap would imply an annual emission rate that is likely to be even more stringent than the regional RGGI target.

Massachusetts and other Regional Procurements In addition to regional emission limits, Massachusetts has required its investor owned distribution utilities to initiate several large procurements and solicitations and enter into cost effective long-term contracts for additional clean energy from base load hydropower resources and Class I eligible renewable energy resources of on and off shore wind and solar power. Together, these three solicitations sought up to 16.5 TWh of clean energy, or approximately one third of total state-wide retail sales.[62] There are three primary solicitations and procurements:

- *Clean Energy RFP*: In 2015, Massachusetts joined Rhode Island and Connecticut in a three state RFP, known as the “Clean Energy RFP”. In that solicitation, Massachusetts sought up to 817 GWh per year of Class I qualified clean energy under 15 to 20 year contracts, under the long-term contracting authority of Section 83(a) of the Massachusetts Green Communities Act. During that solicitation, distribution utilities received 42 project bids for over 5,600 MW of clean energy capacity; in September 2017, the MA utilities and DOER filed with the MA DPU for approval of long-term contracts and power purchase agreements with 10 projects with approximately 420 GWh of annual energy from wind and solar.[63] The final selections included 9 solar projects with a combined capacity of 264 MW and 1 wind project of 126 MW. As of the time of this Report, the DPU has not formally approved contracts and pricing data is not publicly available.

- *2016 Energy Diversity Act, Sections 83C and 83D:* In 2016, Governor Baker signed the Energy Diversity Act, which authorized the procurement of up to 1,600 MW of off-shore wind by 2027 and up to 1,200 MW of clean energy generation (including baseload hydropower). These solicitations are commonly referred to as Section 83C and Section 83D, respectively.

- *Section 83C Offshore Wind:*[64]*:* MA utilities are authorized to enter into cost effective long-term contracts for Offshore wind of up to 1,600 MW of capacity by June 30 2027. Individual proposals must be at least 400 MW, and utilities can enter into staggered contracts, so long as the levelized cost of proposals continue to decline over time. On December 2017, the utilities received bids from three project developers, with flexible configurations for both the total capacity and the size of off-shore transmission facilities. The projects also differ in deliverability and storage configurations; one project is paired with pumped storage to offer base load services, while another offers a lithium ion storage option. These responses totaled a minimum of 1,600 MW and a maximum of 2,288 MW. Bid prices are not publicly available. Projects will be selected for negotiation by April 2018 and final negotiated contracts will be submitted to the MA DPU by July 31, 2018. Projects will be evaluated for cost-effectiveness, including projects ability to provide enhanced electric reliability, contribute to a reduction in winter peak demand, and demonstrate an ability to help meet the GWSA goals in a timely manner. Energy procured under Section 83C will qualify for Class I RECs, as discussed in greater detail below.

  Equally important, several other states have announced plans for off-shore wind procurements. In December 2017, CT issued a draft RFP for comment, seeking up to 825 GWh/year from offshore wind. New York issued a proposal and goal to procure up to 2,400 MW of offshore wind by 2030, in support of its 50 percent clean energy standard. And New Jersey has a soft target for up to 3,500 MW of offshore wind by 2030. Together, analysts estimate the total potential capacity ranging from 4,000 to 8,000 MW by 2030, all located in the Northeast and RGGI states.[65]

- *Section 83D Clean Energy:* At the same time, MA distribution companies also solicited up to 9.45 GWh of clean energy, where clean energy is defined to be any combination of baseload hydropower or Class I eligible resources, either independent or in combination to offer firm service. Resources were required to commit for delivery by the end of 2020. Baseload hydroelectric resources would not qualify for Class I RECs as part of the state's RPS, and the solicitation requires that hydro resources be provided on a firm year-round basis, subject to financial penalty, with contract terms for a period of 15 to 20 years.

  On January 25, 2018, the utilities announced that the Northern Pass Transmission – Hydro bid for an annual purchase of 9.45 GWh of energy was selected for project negotiation.[66] The project included firm service delivery from existing Hydro Quebec reservoirs.

  It was one of several large transmission and hydro projects submitted. On February 1, 2018, the New Hampshire Site Evaluation Committee unanimously voted and denied the siting permit for the proposed transmission route. Following the selection announcement, project developers for the other large scale projects reaffirmed their commitment to similar projects for baseload hydro and/or wind with large scale transmission lines.[67] And on March 28, 2018, the MA utilities moved on from contract negotiations with the Eversource project and selected the Central Maine Power's New England Clean Energy Connect project for negotiations. This project would provide up to 1200 MW of power with an estimate transmission cost of $950 million. Opponents have already filed a motion to intervene before the Maine Public Utility Commission.

Demand Based Policies In Massachusetts, distribution utilities and competitive suppliers are required under the state RPS to procure at least 13 percent of their retail load from renewable resources in 2018 from Class I eligible resources.[68] This requirement increases by one percent per year, up to a 25 percent obligation in 2030. The MA RPS also includes a Solar Carve Out (I and II) with the goal of incentivizing the development of 1600 MW of solar by 2020. MA is now in the midst of developing its successor program, Solar Massachusetts Renewable Target (SMART) to incentivize an additional 1600 MW of solar resources. SMART is expected to be operational at some point in mid to late 2018, and will generate additional RECs for distribution utilities. A primary feature of the SMART program is that projects will qualify for 10 to 20 year fixed price terms for standalone generation. This is in contrast to the variable compensation and revenue offered by SRECs. As part of the motivation for moving to a fixed price term, the DOER notes that "long-term revenue uncertainty [associated with SRECs] leads to higher financing costs."[69]

Appendix II: Energy Efficiency Program Data

As part of each three year energy efficiency program cycle, Massachusetts program administrators publish expected costs and benefits for all associated programs. Data is organized by sector (e.g., residential, commercial/industrial, and low-income), program (e.g., whole house, products or "hard to measure"), and by individual initiatives. Tables 13a and 13b (below) provide the projected 2016-2018 savings and costs, organized by each initiative, as reported by program administrators for the residential and commercial/industrial sectors. We report the total annual energy, total lifetime energy and total program costs. From this data, we also calculate and report the measure life (lifetime energy divided by annual energy), the percentage of total program spending, and the estimated levelized cost of each initiative, where the total cost is calculated as equivalent annual payments over the measure life assuming a three percent discount rate.

We focus on individual initiatives in order to construct a supply curve of potential GHG reduction measures that are likely to be available to the WMLP. This step is required because average residential or commercial costs may over(under) state potential impacts of individual initiatives. For example, residential energy efficiency measures focused on consumer products – including lighting – account for the majority of PA savings and have the lowest total program cost on a dollar per MWh basis. However, these programs are primarily focused on "up-stream" incentives and rebates for suppliers, manufacturers and national retailers, and include broader expenditures for customer marketing, all with a goal of providing greater customer acceptance and savings at the retail level. WMLP customers likely already benefit from these region-wide programs, when purchasing energy efficient appliances from state, regional or national retailers.[70] In contrast, the whole house "measures" or retrofit initiatives include cost and savings data for in home energy assessments, the installation of instant energy savings measures (such as LED light bulbs, faucet aerators and showerheads, and programmable thermostats) and recommendations regarding weatherization and HVAC systems.[71] These initiatives are directly applicable to the WMLP and its customers. Behavioral programs include annual initiatives focused on education and messaging that "seek to identify the motivation factors that cause residential customers to actively employ personal energy savings actions and/or participate in energy efficiency programs."[72]

Table 13: Summary of Statewide Electric Energy Efficiency, Planned Expenditures 2016-2018

Residential

Program	Residential Initiative	Annual Energy (MWh)	Lifetime Energy Savings (MWh)	(%)	Measure Life	Total Program Costs	Levelized Total Program Cost of Energy Savings ($/MWh)
Whole House Initiative	New Construction	22,502	348,390	3%	15.5	$21,167,055	$74.61
	Multi-Family Retrofit	27,914	276,415	2%	9.9	$54,207,177	$222.90
	Residential Retrofits ("Measures")	261,808	2,478,029	19%	9.5	$335,160,970	$152.79
	RCS	0	0	0%		$46,758,383	
	Behavior/Feedback Program	386,504	389,491	3%	1.0	$29,238,247	$75.08
Product Initiatives	Heating and Cooling Equipment	34,206	468,838	4%	13.7	$37,667,231	$96.28
	Consumer Products	37,220	308,721	2%	8.3	$20,752,581	$74.69
	Rebates and Incentives (Lighting)	970,500	9,053,567	68%	9.3	$172,080,294	$21.43
Hard to Measure Initiatives	Statewide Marketing	0	0	0%		$4,540,743	
	Statewide Database	0	0	0%		$468,935	
	DOER Assessment	0	0	0%		$3,273,559	
	EEAC Consultants	0	0	0%		$0	
	Sponsorships and Subscriptions	0	0	0%		$1,701,943	
	HEAT Loans	0	0	0%		$70,261,024	
	Workforce Development	0	0	0%		$604,262	
	R&D Demonstration	0	0	0%		$2,418,555	
	Education	0	0	0%		$7,503,395	
	Total (or Weighted Average)	**1,740,654**	**13,323,450**	**100%**	**7.7**	**$807,804,352**	**$86.59**

Commercial

Program	Residential Initiative	Annual Energy (MWh)	Lifetime Energy Savings (MWh)	(%)	Measure Life	Total Program Costs	Levelized Total Program Cost of Energy Savings ($/MWh)
New Construction	New Buildings and Major Renovations	197,089	3,200,448	12%	16.2	$109,876,316	$42.59
	Initial Purchase and End of Useful Life	145,032	2,342,405	9%	16.2	$69,957,764	$37.01
Retrofit	Existing Building Retrofit	975,848	13,320,690	51%	13.7	$352,417,486	$31.68
	Small Business	312,574	3,255,461	12%	10.4	$184,511,190	$64.88
	Multifamily Retrofit	27,704	257,558	1%	9.3	$33,547,063	$146.79
	Upstream Lighting	605,271	3,743,654	14%	6.2	$80,027,004	$23.05
Hard to Measure Initiatives	Statewide Marketing	0	0	0%		$3,633,789	
	Statewide Database	0	0	0%		$367,178	
	DOER Assessment	0	0	0%		$5,658,750	
	EEAC Consultants	0	0	0%		$0	
	Sponsorships and Subscriptions	0	0	0%		$3,309,246	
	Workforce Development	0	0	0%		$2,338,000	
	R&D Demonstration	0	0	0%		$1,195,000	
	Total (or Weighted Average)	**2,263,518**	**26,120,216**	**100%**	**11.5**	**$846,838,786**	**$58.90**

Notes & Sources: MA EEAC, 2016-2018 Three Year Plan Data Tables, updated December 21, 2015. Available at http://ma-eeac.org/plans-updates/. Costs are levelized assuming a 3 percent discount rate.

Endnotes

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[1] The upper bound assumes the full REC retirement in 2018. See Energy New England, "Portfolio Emissions Evaluation", prepared for the Wellesley Municipal Light Plant, October 31, 2017 and subsequently updated in March 2018. (Hereafter, "ENE, 2018"). As of the writing of this Report, the WMLP was currently developing its strategy regarding existing RECs.

[2] Importantly, this report is focused on options available for achieving GHG reductions in the supply and consumption of electricity starting from current conditions, in order to inform WMLP and Town deliberations on potential pathways for additional reductions. We do not make broad recommendations on whether, to what extent, or at what pace the Town of Wellesley - or the WMLP - should seek to achieve GHG reductions. We also do not investigate specific pathways for achieving reductions in other sectors such as transportation and buildings, though technological and structural changes in the electric industry (discussed in the Phase II report) could potentially contribute to reductions in these sectors (e.g., through proliferation of heat pumps and/or electric vehicles).

[3] These solicitations include the 2015 three state RFP, conducted with Connecticut and Rhode Island, with MA requesting up to 817 gigawatt-hours (GWh) of Class I eligible resources, and the 2017 solicitations under Sections 83C and 83D for up to 1,600 megawatts (MW) of off-shore wind by 2027 and 945 GWh of clean energy by 2022, where clean energy includes both Class I eligible RPS resources and existing hydropower resources. These solicitations were developed as part of the 2008 Massachusetts Green Communities Act and 2016 Energy Diversity Act Amendment.

[4] Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan, 2016-2018, dated October 30, 2015.

[5] That is, we do not consider the purchase of RECs generated through "voluntary" programs outside of the New England Region. See Section II for greater detail.

[6] We recognize that the primary benefit of GHG reductions, and the rationale for considering GHG emission reductions in this context, is the reduction in social, economic, human health and environmental risks associated with climate change associated with anthropogenic emissions of GHG. We assume that the Town's deliberations regarding achieving incremental GHG emission reductions are driven by the recognition of such risks and the Town's collective desire to mitigate them. However, evaluation and/or quantification of the magnitude of these risks (and thus the risk-reduction benefits of emission reductions) is beyond the scope of this study.

[7] This assumes full REC retirement in 2018. Instead, if the WMLP retires only those RECs associated with customer demand in its voluntary renewable energy program, Energy New England estimated total reductions in GHG emissions of approximately 25 percent. See ENE (2018).

[8] Consider for example recent announcements in Maine and New Hampshire, related to wind resources and transmission for large scale hydro, respectively.

On January 24, 2018, Governor LePage of Maine issued an executive order imposing a moratorium on new permits for wind turbines in the state. The Order also established the Maine Wind Energy Advisory Commission, which will issue findings related to the impact of wind development on the State's economy and any proposed policy changes. See http://www.maine.gov/tools/whatsnew/index.php?topic=Gov+News&id=776748&v=article2011

On February 1, 2018, the New Hampshire Site Evaluation Committee unanimously voted to deny the siting permit for the proposed Northern Pass transmission route, which was proposed to deliver 1090 MW of Canadian Hydropower and selected by the MA distribution companies for negotiation of long-term contracts under its Section 83D procurement. On March 28, 2018, the MA utilities moved on from contract negotiations with the

Eversource project and selected the Central Maine Power's New England Clean Energy Connect project for negotiations. This project would provide up to 1200 MW of power. Opponents have already filed motion to intervene before the Maine Public Utility Commission. See https://www.pressherald.com/2018/03/25/unexpected-foes-emerge-to-cmps-power-plan/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202018-03-26%20Utility%20Dive%20Newsletter%20%5Bissue:14606%5D&utm_term=Utility%20Dive

[9] In practice, constraints within the bulk power transmission system lead to losses between the point of generation and the point of delivery. In 2016, line losses in Massachusetts were approximately 5 percent. (See EIA State Profile, Table 10 Source-Disposition). Transmission and distribution losses for the WMLP were approximately 4 percent, based on sales data contained in the 2016 Annual Report. Distribution utility RPS obligations include both retail load and an allocation of line losses. See GIS Operating Rules, Section 8 LSE Obligations, available: http://www.nepoolgis.com/documents/.

[10] Each year, the ISO-NE quantifies system emission rates for generation. These emission rates include the system average, the marginal emission rate for all marginal units, and the marginal emission rate for all thermal units. ISO-NE publishes marginal emission rates by month and for on- and off-peak periods. See ISO New England, System Planning, "2016 ISO New England Electric Generator Air Emissions Report", January 2018.

[11] In MA, there are several tiers or classes of qualified resources. Class I RECs represent generation from qualified resources placed in service after 1997 that are located in New England or connected electricity regions; these resources include new wind, solar, solar thermal, small hydropower, and other alternative resources, including landfill gas. In 2015, landfill gas, biomass, and anaerobic digesters accounted for nearly 20% of all Class I RECs, with landfill gas the third most common resource behind wind and solar. See DOER, Massachusetts Renewable & Alternative Energy Portfolio Standards: Annual Compliance Report for 2015, October 10, 2017 (hereafter, DOER 2017a). The MA RPS includes additional carve-outs are specific requirements for alternative energy portfolio standards, Class II resources built before January 1 1998 and waste energy. See https://www.mass.gov/service-details/program-summaries.

The MA RPS also includes a Solar Carve Out (I and II) with the goal of incentivizing the development of 1600 MW of solar by 2020. MA achieved this goal in 2017 and is in the midst of developing its successor program, Solar Massachusetts Renewable Target (SMART) to incentivize an additional 1600 MW of solar resources. SMART is expected to be operational at some point in mid to late 2018, and will generate additional RECs for distribution utilities. A primary feature of the SMART program is that projects will qualify for 10 to 20 year fixed price terms for standalone generation. This is in contrast to the variable compensation and revenue offered by SRECs. As part of the motivation for moving to a fixed price term, the DOER notes that "long-term revenue uncertainty [associated with SRECs] leads to higher financing costs." DOER, "Solar Massachusetts Renewable Target (SMART) Final Program Design, January 31, 2017, at p. 5. See also, "Installed Solar Capacity in Massachusetts", available: http://www.mass.gov/eea/docs/doer/renewables/installed-solar.pdf

[12] Wellesley Municipal Light Plant, Greenhouse Gas Emission Reduction Consultant Scope of Services.

[13] See "Electricity Sector Regulations Fact Sheet", available: https://www.mass.gov/guides/clean-energy-standard-310-cmr-775

[14] The MA CEC is an economic development agency focused on the growth of the clean energy sector. The CEC meets its mission through investments in programs that increase the adoption of clean energy programs and accelerate the innovation of clean energy technology and infrastructure. Revenues collected through alternative compliance payments are therefore re-invested into CEC programs in part to drive down the costs of future clean energy technologies. See http://www.masscec.com/about-masscec

[15] See https://www.mass.gov/service-details/compliance-information-for-retail-electric-suppliers

[16] DOER 2015 RPS Annual Compliance Reports.

[17] In 2014, total supply exceeded demand by 4%; in 2015, supply exceeded demand by 0.4%. See DOER RPS Annual Compliance Reports, available: https://www.mass.gov/service-details/compliance-information-for-retail-electric-suppliers

[18] See DOER (2017a), Figure 1.

[19] To develop a new project, developers must file with the ISO-NE in the interconnection queue and identify any necessary transmission upgrades to delivery electricity to the grid. Not all projects in the interconnection queue will be built; however, the queue provides one important proxy for future market potential, as identified by prospective developers. This figure includes 1,400 MW of off-shore wind, included in the Bay State wind project and the Revolution project. As discussed in Appendix I, both projects submitted bids to the MA Section 83C solicitation and could be selected as part of the total procurement of 1,600 MW by 2027.

[20] Figure 6 uses RPS demand as estimated by the Lawrence National Berkeley Laboratory in its 2017 Annual Status Report, available: https://emp.lbl.gov/publications/us-renewables-portfolio-standards-0.

Total generation is based on likely estimated renewable additions as sourced from SNL Financial, with a current operating status of "announced, under early development, advanced development or under construction" and all renewable resources that are currently filed in the ISO-NE interconnection queue, irrespective of project status. Total generation is based on average capacity factors for each generation type over the period 2014 to 2016.

[21] ISO-NE, 2018 Regional Electricity Outlook, p. 11.

[22] Synapse Energy Economics and Sustainable Energy Advantage, "An Analysis of the Massachusetts Renewable Portfolio Standard", May 2017, Prepared for the NECEC in Partnership with Mass Energy. See Fig. 8.

[23] As part of the ISO-NE capacity market study conducted in 2016 to estimate future revenues for renewable resources and determine the Offer Review Trigger Price (ORTP), Concentric Energy Advisors used a third-party REC forecast and assumed a constant price of $26.50/MWh (in $2021) over the period 2021 to 2040. We converted this value to $2018 assuming 2.2 percent inflation. See Concentric Energy Advisors, "ISO-NE CONE and ORTP Analysis: An Evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 and forward", October 2016.

[24] See Wellesley Municipal Light Plant, Memo regarding WMLP's Position Regarding Proposed DEP Regulations; WMLP's Purchase of Renewable Power; and WMLP Activities in Support of Town Greenhouse Gas Emission Reduction Goal, June 26, 2017.

[25] Personal communication with the WMLP, May 2018.

[26] See DOER, "Solar Massachusetts Renewable Target (SMART) Final Program Design, January 31, 2017, at p. 5.

[27] The WMLP has also stated that one motivation for their current renewable long-term contracting program is to incentive the development of new resources by providing additional revenue certainty to project developers.

[28] Wellesley Municipal Light Plant, Greenhouse Gas Emission Reduction Consultant Scope of Service, Attachment B, Annual Budget Summaries.

[29] ENE (2018).

[30] Rates include a purchased power adjustment, a conservation service charge, and a credit for New York Power Authority (NYPA) hydropower credit. Fixed charges are $3.90 per billing period. Customers can elect to purchase additional renewable energy on a voluntary basis, up to 100 percent of total requirements. Additional charges increase from $0.0040/kWh for the first 10 percent up to $0.04/kWh for 100 percent renewable. The WMLP reports that 11 percent of customers participate in the program.

[31] Wellesley Municipal Light Plant, 5-Year Financial Forecast, Fiscal Years 2018-2022, Presented to the Municipal Light Board, January 29, 2018.

[32] This forecast level of growth is consistent with the regional outlook for energy demand. The ISO-NE currently forecasts total load growth of -0.64 percent (net of energy efficiency and distributed resources) for the 10 year period out to 2026. ISO-NE, "2017-2026 Forecast Report of Capacity, Energy, Loads, and Transmission", May 2017. See Table 1.5.2.

[33] Wellesley Municipal Light Plant, Memo regarding WMLP's Position Regarding Proposed DEP Regulations; WMLP's Purchase of Renewable Power; and WMLP Activities in Support of Town Greenhouse Gas Emission Reduction Goal, June 26, 2017.

[34] Wellesley College, a campus of approximately 2,350 students and approximately 21 residence halls, is also located in Wellesley Massachusetts. The College self-supplies its own electricity and is partially served by the WMLP. In 2014, total demand from Wellesley College was 26 million kWh, approximately 50 percent of WMLP industrial demand. Wellesley College has agreed to purchase 5 percent of its total electrical consumption from renewable resources. See https://www.wellesley.edu/facilities/sustainability/what-we-re-doing/energy. Wellesley College has set a goal to reduce its GHG emissions by 37 percent by 2026 and 44 percent by 2036 relative to a 2010 baseline. See http://cs.wellesley.edu/~namadeo/sust/

[35] See http://www.babson.edu/about-babson/sustainability/green-campus/Pages/energy-greenhouse-gas.aspx

[36] We note that energy efficiency cost data can be expressed as *program* costs, or the costs accrued by the utility administrator, or the *total resource cost* (TRC) which includes both program costs and participant costs paid by energy users. Throughout this report, we rely on the program cost to estimate the potential impact on the WMLP and consumer rates, and do not consider incremental out of pocket expenses by participants.

[37] Available: http://masssavedata.com/Public/SalesAndSavings

[38] Forecasted sales are based on total demand of 248,200 MWh per year, proportional to 2016 demand by sector.

[39] See, for example: American Council for Energy Efficient Economy, "How Much Does Energy Efficiency Cost?", March 2016 fact sheet; Synapse Energy Economics, "Estimating the Cost of Saved Energy: The EIA 861 Database", December 2016; and Analysis Group, "Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels", December 2014.

[40] We rely on data from the 2016 American Community Survey 5 year estimates. One-year data estimates are not available for areas with populations less than 65,000. 5 year estimates include data collected over a five year period. This provides the most reliable – but least current – estimate. However, the impact of a five year estimate is expected to be minimal given the relatively small changes in total housing units in Wellesley. For example, the 5 year census estimate reports total housing units of 9073 in 2010 and 9134 in 2010. For additional information, see: https://www.census.gov/programs-surveys/acs/guidance/estimates.html

[41] We rely on default model estimates for a 4 kW system with standard modules, fixed open rack, and 14 percent system losses. See http://pvwatts.nrel.gov/pvwatts.php

[42] For example, New York State passed a Clean Energy Standard in 2016. The NY CES created a program for zero emission credits (ZECs) from existing nuclear generation. Load serving entities (LSEs) are required to purchase ZECs each year proportional to their retail load. The price of ZECs adjust each year, based on an assessment of market revenues and the average RGGI allowance price. Nuclear generators are only qualified to sell ZECs after a demonstration of public necessity. The price of ZECs for the period April 2017 to March 2019 is set at $17.48/MWh. See NY PSC Clean Energy Standard Order, Case 15-E-0302/16-E-0270, Issued August 1, 2016, pp. 129 – 141, available: https://www.nyserda.ny.gov/ces. Similarly, Connecticut is also considering potential contracting mechanisms, including with nuclear power, to ensure continued progress towards its GHG emission goals. On February 1, 2018, the Connecticut Department of Energy and Environmental Protection (DEEP) and the Public Utilities Regulatory Authority (PURA) released a final report on resource assessment and determination. They concluded that existing nuclear resources should be eligible to participate in state procurements for new and existing zero carbon resources. In particular, they recommended that contracts with resources found to be at risk of retirement through the submission of "credible financial data" should be evaluated similar to new resources, and consider the value of both price and non-price attributes. Non-price

attributes include the ability to meet state climate and clean air requirements; contribution to fuel diversity and security; local reliability; and other state policy goals. See CT DEEP and PURA, "Resource Assessment of Millstone Pursuant to Executive Order No. 59 and Public Act 17-3; Determination Pursuant to Public Act 17-3", Final Report, February 1, 2018, pp. 39-41. Available at: http://www.ct.gov/deep/cwp/view.asp?a=4405&Q=595018&deepNav_GID=2121

[43] Specifically, we assume a generic project operating at 45 percent capacity factor generating 3,153,600 MWh, and that the WMLP can obtain 0.5 percent, based on the ratio of its annual sales to the 2016 distribution utility sales.

[44] Specifically, we assume that the WMLP can obtain 0.5 percent of available energy, based on the ratio of its annual sales to the 2016 distribution utility sales, and assume the full procurement by distribution utilities of 9.45 TWh per year.

[45] In the short term, LCOE values for wind and solar depend significantly on the investment tax credit (ITC) and the production tax credit (PTC). These credits are currently set to expire by the early 2020s. Absent future extensions, and all else equal, the cost to develop these projects will increase. However, because WMLP is fully hedged through 2021/2022, we assume that any projects with long-term contracts available will not qualify for the full PTC or ITC included in 2017 public estimates, or that the value of these credits will be less than currently estimated based on the changes in the corporate tax rate passed in the 2018 fiscal year.

EIA (2017) provides guidance and a detailed description of how the PTC and ITC are included in their LCOE estimates. Since 2016, the PTC is available to new wind resources, and the PTC provides a $23/MWh inflation adjusted tax credit over the first ten years of operation. The value of the credit depends on the year of construction; and the value of the credit declines by 20% in 2017 through 2019, before expiring completely in 2020. Per IRS guidance, the EIA assumes that the credit is available for up to four years after beginning construction, such that resources entering in 2019 will receive the full credit and resources entering in 2022 will receive 60% of the value, or $14/MWh. In contrast, the ITC is available for new solar PV and thermal plants, and offers a 30% credit on capital expenditures for resources under construction by the end of 2019. The ITC also declines each year, with the credit to residential systems expiring in 2022 and holding constant at 10% for business and utility systems.

[46] Both the EIA (2017) and Lazard (2017) publish LCOE estimates for a similar set of technologies. Those estimates tend to be snapshots for a single point in time and do not present disaggregated regional information.

[47] This represents a generic estimate that is not indexed to any single project or developer. We assume total capital costs of $1.3 billion and a real capital recovery factor of 10%, with levelized costs divided by annual generation of 9.45 TWh.

[48] Between 2014 and 2016, SNL financial estimates that average fixed and variable operating costs for New England nuclear generators was $38/MWh. These costs are consistent with a recent study prepared by Levitan and Associates that estimated the going forward energy market revenues for the Millstone generating facility would be approximately $40/MWh under their base case assumptions, and could range from $30/MWh to $60/MWh under various gas price sensitivities. (See CT DEEP/PURA, Feb 2018) In addition, the NY PSC recently set the value of a zero emission credit (ZEC) from existing nuclear output at $17.48/MWh. This price will adjust after March 2019 based on changes in market futures for energy and capacity, the social cost of carbon, and the average price of RGGI carbon allowances. Together, potential costs and ZECs suggest a proxy price of $55/MWh to $58/MWh. For illustrative purposes, we round this value to $60/MWh and include low and high price sensitivities at $54/MWh and $66/MWh, respectively.

[49] Three percent is routinely use as the "social" discount rate for projects that affect private consumption, as recommended by the Office of Management and Budget (OMB) Circular A-4. In contrast, allocations of private capital (such as investors in a new wind development) may use a higher rate of capital, such as a 7 percent real discount rate or the project specific weighted average cost of capital. In general, a lower discount rate places greater value on future benefits (and costs) and may be more appropriate for projects that reduce GHG emissions many years into the future. See: https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/

[50] For example, a recent analysis by Lawrence Berkeley National Laboratory found that the value of offshore wind (considering energy, capacity and RECs) was higher than that of onshore wind, owing in part to the generation profile of off-shore wind and greater generation during peak demand. That study used historical weather data to simulate generation and actual market prices for the period 2007-2016. See Mills, A. et al., "Estimating the Value of Offshore Wind Along the United States' Eastern Coast", Lawrence Berkeley National Laboratory, April 2018.

[51] The Cost of New Entry (CONE) studies are typically prepared every three years. The most recent study was completed in late 2016 and approved in early 2017.

[52] Notably, the Concentric forecast includes a 1000 MW transmission line with Quebec and 400 MW of off-shore wind. It features new natural gas capacity added to meet system wide resource needs in most years between 2021 and 2036, and includes a CO2 price based on the 2016 RGGI program rule. The Concentric price forecast was developed using an integrated production cost model and natural gas pricing model approach, based on natural gas price forecast developed in Q2 2016 using the GPCM model base case. Gas prices forecasts feature growing constraints after 2030, with price increases exceeding estimated growth forecast in EIA estimates. The Concentric forecast does not assume incremental pipeline capacity for Access Northeast or comparable projects after 2018.

Based on our review, this price forecast represents one of the most reliable and current publicly forecasts available. More recent forecasts include the EIA Annual Energy Outlook. However, this price forecast includes an estimate of both marginal energy and marginal capacity prices in a single estimate. Because GHG emission reduction measures may have significantly different peak energy profiles – and subsequent impacts on avoided capacity revenues – we did not use this integrated price forecast.

[53] See "a4_a_e_and_as_model_cc_technology.xlsx" posted to the Markets Committee, November 30, 2016.

[54] Schatzki, T. and Llop, C. "Capacity Market Impacts and Implications of Alternative Resource Expansion Scenarios An Element of the ISO New England 2016 Economic Analysis" May 17, 2017.

[55] ISO-NE System Planning, "Transmission Planning Technical Guide", Effective Date November 14, 2017.

[56] Pay for performance adjustments in the FCM depend, in part, on average unit performance during shortage events. In 2013, Analysis Group found that the average performance (estimated as output divided by claimed capacity) for nuclear units during shortage events was greater than 100 percent in both summer and winter periods. See Schatzki, T. and Hibbard, P. "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives", prepared for ISO-NE, September 2013.

[57] See, for example, Tierney, S. "The Value of 'DER' to 'D': The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability", March 31, 2016.

[58] See Appendix I; Distribution utilities received 42 project bids for over 5,600 MW of clean energy capacity as part of the 2015 RFP. In September 2017, the MA utilities and DOER filed with the MA DPU for approval of long-term contracts and power purchase agreements with 10 projects with approximately 420 GWh of annual energy from wind and solar.

[59] For a recent overview of the issue, see Roberts, D. "Is 100% Renewable Energy realistic? Here's what we know. Reasons for skepticism, reasons for optimism, and some tentative conclusions." VOX, Feb 7, 2018, available: https://www.vox.com/energy-and-environment/2017/4/7/15159034/100-renewable-energy-studies. That study provides a summary of both Jenkins and Thernstrom (2017) and Heard, Brook, Wigley, and Bradshaw (2017).

[60] That is, we do not consider the purchase of RECs generated through "voluntary" programs outside of the New England Region. See Section II for greater detail.

[61] This estimate does not consider the banking or trading of allowances in future years and is based on the RGGI 9-state region. Actual emission rates in ISO-NE may be higher or lower, depending on the relative imports or

exports of electricity between states and the total quantity of system generation, including renewables as forecast to meet regional RPS goals.

[62] Assumes a 45 percent capacity factor for offshore wind. Total retail sales of 53,475,888 MWh are based on 2016 EIA data, form 861. See https://www.eia.gov/electricity/state/massachusetts/

[63] Joint Direct Testimony of Jeffrey S. Waltman, Corinne M. Didomenico and Lisa S. Glover, Petition for Approval of Proposed Long-Term Contracts for Renewable Resources Pursuant to St. 2008, c. 169, § 83A, D.P.U. 17-117-120.

[64] See generally, https://macleanenergy.com/83c/

[65] Sustainable Energy Advisors, "Northeast Offshore Wind Regional Market Characterization: A Report for the Roadmap Project for Multi-State Cooperation on Offshore Wind", October 2017, Report Number 17-21.

[66] https://macleanenergy.com/2018/01/25/the-distribution-companies-and-department-of-energy-resources-have-completed-the-evaluation-of-83d-bids-received/

[67] See: http://www.transmissionhub.com/articles/2018/02/projects-continue-to-advance-following-massachusetts-rfp-outcome.html

[68] In MA, there are several tiers or classes of qualified resources. Class I RECs represent generation from qualified resources placed in service after 1997 that are located in New England or connected electricity regions; these resources include new wind, solar, solar thermal, small hydropower, and other alternative resources, including landfill gas. In 2015, landfill gas, biomass, and anaerobic digesters accounted for nearly 20% of all Class I RECs, with landfill gas the third most common resource behind wind and solar. See DOER, Massachusetts Renewable & Alternative Energy Portfolio Standards: Annual Compliance Report for 2015, October 10, 2017 (hereafter, DOER 2017a).

The MA RPS includes additional carve-outs are specific requirements for alternative energy portfolio standards, Class II resources built before January 1 1998 and waste energy. See https://www.mass.gov/service-details/program-summaries.

[69] See DOER, "Solar Massachusetts Renewable Target (SMART) Final Program Design, January 31, 2017, at p. 5.

[70] See Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan, October 30, 2015, p. 93: "Upstream incentives/negotiated promotions provide instant price discounts to the customer for qualified products. The price reductions provided by incentives and promotions makes lighting products more attractive and affordable to the customers, which in turn increases the number of retail outlets willing to carry these products." (hereafter, Three Year Plan (2015))

[71] See Three Year Plan (2015), pp. 61 to 96.

[72] Three Year Plan (2015), p. 74.