# Restructuring Connecticut's Renewable Portfolio Standard

## DRAFT

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# EXECUTIVE SUMMARY

Connecticut's existing Renewable Portfolio Standard (RPS) does not align with the Governor's goal of providing cheaper, cleaner, and more reliable electricity for the state's citizens and businesses. The present RPS framework has resulted in the State's Renewable Energy Credits (RECs) coming largely from out of state and not-very-clean biomass burning and landfill gas. The present framework leaves ratepayers exposed to potential price volatility from inadequate supply of renewable power to meet the targets that have been set and to saddle the state with a potential for high "alternative compliance" payments (self-inflicted penalties that do not correspond to renewable power gains). Connecticut's commitment to expanded electricity generation from renewable sources needs to be updated and restructured to ensure that the state will continue to be a driving force in the emerging clean energy economy while recognizing the imperative to hold down electricity costs for ratepayers – protecting family budgets and business competitiveness.

This draft study recommends a new approach to renewable electricity generation. It calls for a revised RPS that would ensure that renewable resources supply an increasing share of Connecticut's electricity, maximize the benefits of a more diverse power supply, improve our electric system's reliability, advance greenhouse gas and air emission controls, and support local renewable projects that bring jobs and revenue to Connecticut's economy while at the same time minimizing the costs for electric ratepayers. Specifically, the draft study proposes to deepen our commitment to renewable energy by raising Connecticut's RPS goal from 20% renewable, class I power generation by 2020 to a target of 25% by 2025, while spurring innovation in the renewable power marketplace by creating a flexible "contracted-tier" structure that will ensure that Connecticut ratepayers are paying as little as possible for this strengthened renewable energy commitment.

This draft study also proposes to reform the existing standards to ensure that the cleanest and most cost-effective renewable energy is being procured for Connecticut ratepayers -- and that Connecticut residents will see the in-state economic benefits associated with the emerging clean energy economy. In particular, the draft study reinforces the commitment to in-state deployment of solar power, fuel cells, and other renewable projects. The draft study also calls for the standards that apply to biomass burning to be tightened and the phase out of REC credit for landfill gas – creating a broader regional incentive for new renewable power projects. It further recommends discontinuing Class III incentives for utility-administered energy efficiency programs that are already ratepayer funded. The policy logic for awarding Class III RECs to these programs (de-funding of the conservation load and management program) no longer holds and the flow of resources to energy efficiency from a various sources is increasing.

**Restructuring Connecticut's Renewable Portfolio Standard**

This draft study does not change the basic policy framework of the RPS, which establishes a financial incentive for developers to bring renewable power projects into the marketplace by requiring electricity providers to purchase an escalating percentage of the power they supply from renewable sources. Connecticut's existing RPS thus requires that the state's electricity providers procure 10% of their total electricity from renewable sources this year, rising to 20% by 2020. Owners of electricity generation projects that qualify as renewable under one of the three classes of Connecticut's RPS receive one renewable energy certificate (REC) for every megawatt-hour (MWh) of electricity they produce. These RECs have a dollar value attached to them as power suppliers must reconcile each year the electricity they supply to the marketplace with the RECs they have purchased.

Connecticut's existing RPS dates to 1998, and has escalating commitment to renewable generation designed to achieve several objectives: reduce dependence on fossil fuels, create a hedge against volatile oil and natural gas prices, lower air emissions, and promote clean energy jobs and economic development. The RPS approach was designed to allow more expensive renewable technologies to secure the financing necessary for their development by guaranteeing a market for the power they generated. While these technologies were in their infancy in 1990s, the belief was that the RPS support would spur deployment and innovation in renewable generation that in turn would produce economies of scale and lower prices.

The vision that motivated the launch of the RPS in 1998 remains valid, but the incentives and framework need to be updated and their focus sharpened. In particular, the state needs a refined approach to renewable energy that sets the state up to push past an era of subsidies for clean energy and reward those technologies that are able to compete with and ultimately out-compete conventional fossil fuel electricity generation. For example, the per-kilowatt-hour installed cost of solar photovoltaic (PV) systems has declined by 35% in the past decade, and some experts expect solar PV systems to cost less than retail rates for electricity purchased from utilities within the next five years, even without subsidies.[1] The strategy proposed in this document reflects the need to better harness market forces, and to use policy to drive innovation in the market and maximize deployment by rewarding the lowest cost renewable generation.

An analysis of compliance with the current RPS reveals that Connecticut ratepayers are in immediate danger of shouldering a growing economic burden while receiving little of the environmental or economic benefits envisioned when the original RPS was adopted. This draft study, prepared by the Department of Energy and Environmental Protection (DEEP) in accordance with Public Act 11-80, concludes that there are numerous steps that can be taken to re-craft Connecticut's RPS so as to better achieve those objectives and do so in a more cost-effective way. Among the issues with the status quo:

[1] Black & Veatch, Cost and Performance Data. Available at http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

- In-state renewable projects account for only 11% of Connecticut's Class I RPS standard. This means that 89% of the investment that is being made in renewable generation is being spent outside of the state, and Connecticut does not enjoy the economic benefits associated with in-state projects.
- A total of 76% of Connecticut ratepayer's investment in Class I resources is going to support biomass plants located primarily in Maine and New Hampshire. These plants are among the least "clean" Class I resources and (because many were already in operation when the RPS was enacted).
- Another 13% of Connecticut's Class I requirement is currently supplied by landfill gas projects located primarily out-of-state. The clean energy produced by a few of these projects is already counted towards New York's renewable goals. Consequently, although Connecticut subsidizes those plants through its RPS, the output from these resources is being double counted. In addition, the investment costs for these facilities have long since been recovered which means the REC purpose of supporting investment has already occurred.

The markets for Class II and Class III Renewable Energy Credits (RECs) are also falling short of Connecticut's RPS objectives. These classes within the RPS were designed to drive growth of cleaner and more cost-effective generation as well as energy conservation measures. Both Class II and Class III are oversupplied with eligible resources, resulting in low prices and limited incentives that do little to support new or existing investments. This problem of oversupply is compounded by the fact that Connecticut's Class III tier currently provides incentives for efficiency investments made through the state's Conservation and Load Management programs, which are already supported by ratepayer funds and increasingly leveraged with private capital through the Clean Energy Finance and Investment Authority (CEFIA). To ensure the cost-effectiveness and greater environmental impact of the state's RPS program, this draft study recommends the following changes designed to drive innovation in the marketplace, more strategically align our RPS requirements with those of other states, address the oversupply in some markets, restore meaningful incentives to project developers, secure increasing amounts of clean renewable energy, and reduce overall program costs:

- **Continue commitment in existing programs to maximize deployment of cost-effective in-state renewable power.** As of 2011, Connecticut produced only about 5% (66 MW) of New England's renewable capacity, while accounting for more than a third of the Class I RPS demand in the region. As a result of newly launched renewable energy programs such as the funding coming from the nation's first "Green Bank" and the Low Emissions and Zero Emissions Renewable Energy Credit programs, Connecticut has increased its deployment of in-state Class I resources ten- fold since 2010: the state is on track to deploy an additional 55 MW of clean, Class I electricity in 2013, and 5% of the state's total electricity demand will be supplied by in-state renewables by 2020.

- **Support gradual transition away from subsidies for older biomass plants and landfill gas that do not provide optimal economic or environmental benefits.** This draft study recommends a phase-in of more stringent standards that will either ensure that biomass plants deliver cleaner energy justifying ongoing qualification as Class I renewable power or allow their replacement with new cleaner resources such as wind power, solar arrays, or other zero-emissions renewables.

- **Expand support for small hydropower, anaerobic digesters, and biologically-derived methane.** Under current RPS rules, to qualify for Class I a hydro project must be built after 2003, be run-of-river, and have a generating capacity of less than 5 MW to qualify. This study recommends increasing the definition for Class I hydro eligibility from 5 MW to 30 MW to conform with Massachusetts and replacing "run-of-the river" with Low Impact Hydro Institute certification. Connecticut allows "methane from landfill gas" as a Class I resource, as do each of the other New England states. The Class I resource definition should also be modified to allow all methane/biogas that is biologically derived—i.e., from sources such as yard and plant matter, food waste, animal waste and sewage sludge— and produced by new technologies such as anaerobic digesters to qualify as a Class I source.

- **Allow less expensive large-scale hydropower to qualify as a Class I resource (in a separate "contracted tier" without premium) to complement in-state and regional renewable energy procurements.** Large scale hydropower resources, such as those found in Quebec and the Canadian maritime provinces offer a source of renewable power at very competitive costs. This study thus recommends that a set portion (or contracted tier) of Connecticut's Class I RPS percentage requirements be allowed to be filled by large-scale hydropower, beginning at 2% of the Class I target in 2014 and gradually increasing by 1% annually up to a maximum of 4.5% in 2020 and 7.5% in 2025. Large-scale hydropower would only be eligible within this "contracted tier." It would not compete within the rest of the Class I market nor would it have a REC attached to it. This power would be procured under a long-term contract, with large-scale hydro and all other Class I projects being eligible to compete.

- **Provide a flexible mechanism for the state to procure low-cost renewable supply.** DEEP should be given authority to participate in a regional procurement for Class I resources, and to conduct a procurement of large-scale hydro (greater than 30 MW). The resources selected from the first procurement would be done in conjunction with other New England states in 2013 and would be used to meet the existing Class I requirements. The second procurement would target the "contracted tier" of large scale hydropower or other low-cost renewable, beginning in 2014.

- **Discontinue Class III incentives for efficiency programs that are already ratepayer funded.** As is the case with Class II resources, there is a significant oversupply of Class III resources. Since the programs provided through the State's Conservation and Load Management Plan are already supported through ratepayers, this draft study recommends that any efficiency programs supported by ratepayer funding not be eligible to qualify for additional ratepayer support through the Class III market. Eliminating these resources would open up the market to more combined heat and power (CHP) projects.

The recommendations described above will enable Connecticut to achieve a more balanced and flexible approach to renewable power development, continue support for in-state renewable power projects that benefit the local economy while working with neighboring states to procure the cheapest possible regional renewable resources in the near term, and maintain the flexibility to purchase large amounts of low-cost, large-scale hydropower in the event that cost-competitive regional Class I resources are in short supply. By taking structured steps to procure renewable electricity, Connecticut can also help to drive smart investments in transmission that will reduce greenhouse gas emissions, improve the flexibility and reliability of the electricity grid, achieve rate suppression in Southern New England, provide a hedge against spikes in natural gas prices, and potentially secure greater supplies of clean, low-cost power during times of peak demand. This strategy would also provide a flexible glide path toward the day that Connecticut's nuclear plants shut down.

Simply put, the restructuring proposed of the Connecticut RPS framework would position the state to be a leader in the pursuit of renewable power on a basis that promotes innovation, drives cost reductions, and advances the emerging clean energy economy on a sustainable basis. The new RPS structure would reinforce the policy direction of Connecticut's new Comprehensive Energy Strategy – and advance the Governor's commitment to cheaper, cleaner, and more reliable electricity.

## INTRODUCTION

In 1998, Connecticut became one of the first states in the country to financially support the development of renewable energy by enacting a renewable portfolio standard (RPS).[2] At that time, traditional renewable energy sources (wind, solar, small-scale hydropower) were generally more expensive than traditional central power station generation derived from oil, coal, and natural gas. The RPS model was adopted by states wishing to encourage the development of new renewable energy projects and — in states like Connecticut which undertook electricity market restructuring — to support continued operations of existing renewable energy generation.

Connecticut's RPS was designed to achieve several objectives: diversify the state's energy resource mix to promote reliability, provide a hedge against volatile fossil fuel prices, improve environmental conditions by reducing air emissions, create clean energy jobs, and enhance the quality of life in the state. The RPS has been amended several times since its enactment, to extend and increase Class I requirements, adjust the eligibility criteria for Class I and Class II renewable sources, and to add a new Class III to support combined heat and power (CHP) projects and energy efficiency.[3]

Despite these amendments, there have been continued calls to review and refine Connecticut's RPS. In a 2011 report, the Connecticut Energy Advisory Board (CEAB) expressed concern that the policy objectives of the RPS needed to be more clearly defined and prioritized, and that more regular and formal analysis was needed to determine whether and how the RPS could better meet those objectives.[4] Public Act 11-80, enacted in 2011, answered the CEAB's call for further analysis of RPS by directing DEEP to conduct a comprehensive review of the RPS, which culminated in this study.[5]

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[2] Connecticut General Assembly H.B. 5005 "An Act Concerning Electric Restructuring", 1998.

[3] The Center for Energy, Economic, and Environmental Policy and the Rutgers Economic Advisory Service, "A Review of Connecticut's Renewable Portfolio Standards", Edward J. Bloustein School of Planning and Public Policy, Rutgers, the State University of New Jersey for the Connecticut Energy Advisory Board, July 18, 2011, retrieved from http://www.ctenergy.org/pdf/CTRPSFORCOMMENT.pdf at 8.

[4] Id.

[5] Section 129 of Connecticut General Assembly S.B. 1243 "An Act Concerning the Establishment of Energy and Environmental Protection and Planning for Connecticut's Energy Future", 2011. Public Act 11-80 requires the Department of Energy and Environmental Protection (DEEP) to conduct a review of the Connecticut RPS. The legislation further specifies that the review contain an analysis of certain elements of the RPS including: (1) options for minimizing the cost to electric ratepayers of procuring renewable resources, and (2) the feasibility of increasing the RPS target. A final requirement is that DEEP, in its review, "consider the impacts, costs, and benefits of expanding the definition of Class I renewable sources to include "hydropower and other technologies that do not use nuclear or fossil fuels."

This study offers a new approach to Connecticut's support for renewable electricity generation that will move the state toward Governor Malloy's model of a cheaper, cleaner, more reliable energy future. This approach will ensure that renewable resources supply an increasing share of Connecticut's electricity, maximizing the benefits of a more diverse power supply to increase reliability, reducing greenhouse gas and other air emissions, and supporting local renewable projects that bring jobs and revenue to Connecticut's economy—while at the same time minimizing the overall cost of renewable to Connecticut's electric ratepayers.

The 2011 legislation further specified that the review contain an analysis of certain elements of the RPS including: (1) options for minimizing the cost to electric ratepayers of procuring renewable resources, and (2) the feasibility of increasing the RPS and (3) "the impacts, costs, and benefits of expanding the definition of Class I renewable sources to include . . . hydropower and other technologies that do not use nuclear or fossil fuels."[6] The results of DEEP's review of the Connecticut RPS are encompassed in this study.

In conducting its analysis, DEEP assessed the current RPS structure to determine how effectively it supports the development of new renewable resources. The study then considered the potential impact of a variety of modifications to the RPS and other policies that might promote clean energy resource development. DEEP recognizes that a successful renewable portfolio standard must harmonize energy, environmental, and economic objectives. Certain policy options may minimize costs to Connecticut's ratepayers but at the same time limit the diversity of the state's energy portfolio. Other options may fulfill environmental goals while simultaneously hindering in-state economic development or dramatically increasing costs. The proposals and options offered herein are designed to drive down the cost of new renewable energy technologies and enable older renewable technologies to achieve cost-competitiveness, by harnessing market forces and competitive pressures to spur innovation and economies of scale.

It is important to recognize that frequent modifications to the RPS run the risk of devaluing some of the investments it was intended to support, or deterring potential investors from investing in new renewable projects to meet the RPS goals, for fear that the RPS rules will change again. Therefore, to protect the integrity of the RPS market, any changes to resource eligibility should be carefully defined and appropriately phased in sufficiently far in the future to allow for a reasonable transition that minimizes risk to existing investments.

[6] PA 11-80 Section 129

To assist with the development of this study, DEEP retained an outside consultant, Sustainable Energy Advantage LLC, to prepare two white papers that provide additional technical analysis of (1) the issues and options associated with incorporating substantial low-cost/no premium renewable energy (large hydro-eligible) contracts into a Connecticut Class I RPS Sub-Tier ("Large Hydro White Paper" – Appendix I), and (2) the issues and options associated with potential adjustments to Connecticut Class I RPS eligibility ("Eligibility White Paper" – Appendix II). These documents are available on the DEEP website.[7] DEEP welcomes comments on this Study and the associated White Papers during a 30-day comment period.[8] After consideration of all comments submitted, DEEP will finalize this study for submission to the General Assembly.

# BACKGROUND

## Connecticut's RPS Structure in a Regional Context

A renewable portfolio standard is a policy mechanism that creates a financial incentive for developers to develop renewable energy projects, by requiring electricity providers to purchase set quantities of renewable energy thereby guaranteeing a market and steady stream of revenue for renewable generators. Under Connecticut's RPS, electricity providers who serve retail customers in Connecticut must obtain a certain percentage of the energy they sell to these customers from three categories, or "classes," of renewable energy generators, listed in Table 1.[9]

Owners of electricity generation projects that qualify as renewable under one of the three classes of Connecticut's RPS receive one renewable energy certificate (REC) for every megawatt-hour (MWh) of electricity they produce. These RECs are tradable commodities that allow the environmental attribute of the renewable energy to be bought and sold separately from the energy commodity itself. A renewable generator can either contract to sell its energy—"bundled" with the accompanying attribute value (REC)—directly to an electricity provider (usually at a premium above the wholesale electricity price), or it can "unbundle" the REC and the energy and sell them separately in regional wholesale markets.

[7] http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=6

[8] Information about how to submit comments, as well as a schedule for a technical meeting on this Study are available on the DEEP website at http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=6

[9] In Connecticut, these electricity providers include the state's electricity distribution companies (EDCs), which purchase energy on behalf of standard service customers who continue to receive standard service, as well as retail electric suppliers that serve customers who have opted to purchase their electricity from a competitive supplier.

Under the current RPS, the percentage of electric load that must be met by Class I sources increases over time, from 10% in 2013, up to 20% in 2020. The Class II RPS requirement is 3% in 2012 and remains at that level through 2020 and the Class III RPS requirement, currently 4%, also remains constant through 2020. In the event that the supply of renewable energy in any of these classes is inadequate to meet the RPS requirements, electricity providers must comply with the RPS by making an Alternative Compliance Payment (ACP), which is set by statute at $55/MWh. Any revenues collected from Alternative Compliance Payments are allocated to the Connecticut Clean Energy Finance and Investment Authority (CEFIA) to support the development of additional Class I resources.

**Table 1: Connecticut RPS Classes and Eligibility Requirements**

| Class | Target (2013-onward) | Eligible sources |
|---|---|---|
| **Class I** | 10% in 2013; increases annually up to 20% in 2020 | • Solar<br>• Wind<br>• Fuel cell<br>• Methane gas from landfills<br>• Ocean thermal<br>• Wave<br>• Tidal<br>• Run-of-river hydropower (<5MW, began operation after July 1, 2003)<br>• Sustainable biomass (NOx emission <0.075lbs/MMBtu of heat input, <500kW, began operation after July 1, 2003)<br>• Low emission advanced renewable conversion technologies |
| **Class II** | 3%; does not increase | • Biomass (NOx emission <0.2 lbs/MMBtu of heat input, began operation before July 1, 1998)<br>• Small run-of-river hydroelectric (<5MW, began operation before July 1, 2003)<br>• Trash-to-energy facilities |
| **Class III** | 4%; does not increase | • Customer-sited combined heat and power (CHP) with operating efficiency >50%, facilities installed after January 1, 2006<br>• Waste heat recovery systems installed on or after April 1, 2007<br>• Electricity savings from conservation and load management programs (begun on or after January 1, 2006) |

Source: Conn. Gen. Stat. §16-1(a) (26), (27), (44) & (45)

Connecticut's RPS policies must be viewed in a regional context. All of the New England states except Vermont have renewable portfolio standards. Under rules currently in effect in Connecticut and all other New England states, electricity providers can satisfy their RPS requirements with RECs purchased from renewable generation projects located in the ISO-New

England control area (which includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut), or with RECs for energy imported into ISO-NE from an adjacent control area (i.e., Quebec, the Maritimes Control Area, or New York). Renewable generation within the ISO-New England control area is certified and tracked through a system called the NEPOOL Generation Information System (GIS).

While the geographic eligibility rules are the same across New England, each state's RPS has different eligibility criteria, percentage requirements, and ACP prices. For example, Connecticut's ACP is set statutorily at $55 per megawatt-hour (MWh) for all classes. Maine, Massachusetts, and Rhode Island have higher ACP levels for Class I, which are adjusted annually. Since the ACP is higher in those states, Connecticut may be the last to receive multi-state qualified RECs such as solar and wind when there are shortages. An actual shortfall would also occur in Connecticut a bit sooner than other states since Class I eligible projects would be more inclined to sell their RECs in states with a higher ACP. As a result of the differences in state eligibility requirements, a higher proportion of Connecticut's Class I RPS requirement will be filled with sources that only qualify in Connecticut, such as "legacy" (pre-1998) generation (primarily biomass and land fill gas) as well as fuel cells using natural gas.

These differences among state's RPS design have important consequences for the type—and price—of renewable generation that electricity providers will buy to comply with Connecticut's RPS. This, in turn, affects Connecticut's ability to achieve the policy objectives of its RPS, particularly within Class I. In the sections that follow, this study evaluates the types of resources that are currently supplying each class of Connecticut's RPS, and the current and projected costs of those resources, to determine how well, and how cost-effectively, the current RPS structure is providing cheaper, cleaner, and more reliable electricity. Before turning to the review of Connecticut's RPS classes, however, the study first provides an overview of renewable energy and energy efficiency programs established by the State to support in-state renewable energy projects. While separate from the RPS itself, these programs are having a significant impact on the amount of cost-effective in-state renewable generation that is or will become available to supply Connecticut's RPS requirements.

## Connecticut Renewable Energy and Energy Efficiency Programs

As of 2011, Connecticut had only about 5% (66 MW) of New England's installed renewable capacity, while it accounted for more than a third of the Class I RPS demand in the region.[10] In recent years, Connecticut has sought to remedy that imbalance by implementing programs to accelerate support of in-state renewable and energy efficiency projects, while also seeking to drive down costs. By using low-cost financing, targeted grant funding, and reverse auctions tied to long-term contracting, these programs are significantly increasing the amount of in-state capacity available to supply the state's RPS requirements. For example, 55 MW of renewable generation is set to come online in 2013 as a result of these new programs – a tenfold increase over previous years. Over the next ten years, these programs are expected to increase the percentage of the state's electricity demand supplied by in-state renewables from 1% to about 5-6% in 2022. These programs are described in more detail below.

Over the years, Connecticut has provided significant support for Class I and Class III resources. Connecticut's Project 150 program, launched in 2003 and later amended, required local electric distribution companies (EDCs) to enter into long-term contracts to purchase at least 150 MW of Class I renewables. Fourteen projects totaling 159.8 MWs were approved for participation in the program, but as of 2011 only four projects equaling approximately 47 MW appear to have been financed or are otherwise moving forward towards completion.[11] In addition to Project 150, Connecticut established a ratepayer funded grant and incentive program to promote the development of combined heat and power (CHP) projects, which qualify as Class III resources. This program resulted in the development of approximately 100MW of CHP between 2006 and 2009.

The passage of Public Act 11-80 in 2011 launched a series of new programs designed to dramatically increase the amount of in-state Class I renewable resources at increasingly lower costs, by using competitive procurements and leveraging ratepayer contributions. Public Act 11-80 established the nation's first "Green Bank", called the Connecticut Clean Energy Finance and Investment Authority (CEFIA), to promote investment in clean energy sources. CEFIA was also charged with developing a program to incentivize residential solar PV installations.[12] This program will support the deployment of at least 30 MW of new residential solar capacity by December 31, 2022. As of March 2013 (one year after the program launch), this program has

[10] 2012 Integrated Resource Plan, Appendix D-8
[11] Docket No. 11-07-06
[12] Section 106 of Public Act 11-80.

already resulted in 8.2 MW of residential solar installations in development at an average price of $4.65 per watt.[13]

Public Act 11-80 also established a Zero Emission (ZREC) and Low Emission (LREC) Renewable Energy Credit program.[14] Over six years beginning in 2012, the ZREC/LREC program requires the state's electric distribution companies (EDCs) to enter into $8 million worth of long-term (15 year) contracts annually for ZRECs (renewable energy credits from "zero-emission" Class I renewable energy resources such as solar, wind, and small hydro) and $4 million worth of 15-year contracts annually for LRECs (renewable energy credits from "low-emission" Class I resources such as fuel cells, biomass, and landfill gas that meet certain emissions standards). The ZREC/LREC program utilizes a reverse auction structure, in which contracts are awarded on a competitive basis to the projects requiring the least subsidy. In its first year, the ZREC/LREC program resulted in contracts for more than 31 MW of renewable generation, with an average subsidy of 9 cents per kWh, well below the statutory price cap of 35 cents per kWh.[15]

Section 127 of Public Act 11-80 provided further support for Class I renewables by allowing private developers and the state's EDCs to submit proposals for up to an aggregate of 30 MW of new Class I renewable energy sources. DEEP conducted a competitive procurement and selected two 5 MW solar energy projects (East Lyme Solar Park and Somers Solar Center) for long-term power purchase agreements, representing one-third of the renewable generation procurement mandated by the Act. The EDCs are continuing to work on the development and approval of projects pursuant to their part of Section 127.

Finally, Public Act 11-80 established programs to support anaerobic digesters,[16] as well as small combined heat and power projects.[17] All of these in-state projects play a critical role in ensuring that the economic benefits associated with meeting the RPS accrue to the citizens of Connecticut.

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[13] The rebates and performance-based incentives to support this program equate to a 15-year ZREC price of about $110 per REC.

[14] Sections 107 and 110 of Public Act 11-80

[15] www.ct.gov/energystrategy Connecticut Comprehensive Energy Strategy, p. 89

[16] Section 103 of Public Act 11-80 requires CEFIA to establish a three-year pilot program to support businesses using organic waste with on-site anaerobic digestion to generate electricity and heat. No more than five projects shall be approved, with a maximum size of one thousand five hundred kilowatts at a cost of four hundred fifty dollars per kilowatt. CEFIA is to allocate two million dollars annually from the Clean Energy Fund.

[17] As a result of the Public Act 11-80, DEEP was required to conduct a review of appropriate financial incentives to encourage installation of combined heat and power (CHP) – also known as "cogeneration" – systems of up to one megawatt of capacity. Following the review process, DEEP approved financial incentives of $200 per kilowatt (kW). CHP projects are also eligible for grants of $350 per kW from CEFIA. These programs are open to all developers of CHP systems, including municipalities.

# RPS COMPLIANCE TO DATE

DEEP estimates that the investment of Connecticut ratepayers to support RPS generation sources was approximately $168.1 million in 2012, with Class I resource accounting for about 90% of that total.[18] In August 2012, Class I RECs sold for approximately 5.2 cents/kWh, reflecting a recent upswing as a result of the supply going from surplus into shortage. Through 2012, the RPS targets have been met for all RPS classes and a surplus of Class II and Class III renewable resources continues to exist. This surplus has served to drive down Class II and Class III REC prices: in August 2012, the price of Class II was 0.4 cents/kWh, and Class III sold at the floor price of 1 cent/kWh. Under Connecticut's RPS, the Class II and Class III targets do not increase. Therefore, it is expected that the surplus supply will continue to keep Class II and III REC prices low and costs relatively constant through 2020.

In the sections that follow, DEEP has made projections of the future cost of compliance with Class I, Class II, and Class III RECs. In its projections, DEEP included the total above-market cost for renewable energy including RECs, plus other Connecticut renewable program costs, and any incremental transmission costs projected to be supported by Connecticut electric ratepayers not factored into the projected cost of the REC. These historic compliance costs and future projections do not include other impacts that may benefit Connecticut ratepayers by reducing the price of energy and capacity purchases, natural gas price suppression, or the economic benefits accruing to Connecticut from in-state renewable generation.

# CLASS I RESOURCES

## Connecticut Class I Resource Characteristics

RPS targets and eligibility criteria drive different policy goals within RPS classes. Some RPS classes function as *maintenance* tiers, with stable targets intended to maintain certain types of so-called "legacy" clean energy facilities that qualify as a "pre-RPS vintage"—meaning that the projects were already in existence when the RPS went into effect. These projects were made eligible for RECs when the RPS was first enacted in 1998, so as not to undermine support they had received in the pre-restructured energy market. By contrast, other RPS classes function as *growth* tiers, designed to spur investment in new renewable facilities by providing for increasing

[18] These estimates of the RPS costs to date are based on historic spot REC prices and only include the cost of RECs. DEEP did not attempt to estimate or include the cost of other subsidies or transmission costs that were incurred for existing resources that qualify for Connecticut's RPS. Nor did DEEP attempt to estimate the value of any hedging through longer-term contracts that may have occurred at lower prices than the spot REC price.

targets and narrower "vintage" eligibility requirements that restrict eligibility to facilities that were developed after the RPS went into effect. Because these new renewable facilities are "additional" to the electric system, they provide so-called "additionality" benefits by increasing the diversity of the fuel supply, displacing fossil fuel use, and reducing greenhouse gas and other emissions.

Connecticut's RPS classes have characteristics of both maintenance and growth tiers.[19] Like growth tiers in other states, Connecticut's Class I tier currently has an increasing target, rising from 10% to 20% by 2020. Unlike growth tiers in other states, however, Connecticut's Class I allows pre-RPS vintage generation to continue to qualify regardless of whether their initial investment obligations have been met. This means that RECs from legacy facilities that do not qualify for growth tiers elsewhere in the region do count towards the Class I target in Connecticut.

As a result, for example in 2010, more than three-quarters of Connecticut's Class I target was supplied by wood and biomass facilities located in Maine and New Hampshire that are often not eligible as a Class I source in other New England states (Figure 1). Another 13% of Connecticut's Class I target in 2010 was supplied by landfill gas plants, located primarily in New York.

In 2010, only 11% of Connecticut's Class I obligation was met by Connecticut based solar, fuel cells, or wind. As illustrated in Figure 2, below, most of the renewable power filling Connecticut's Class I target in 2010 was generated in facilities located in other states in the region. Fortunately, these new resources are growing rapidly. Solar and fuel cells represent the largest potential for growth in Connecticut based Class I resources. Wind has, by far, the largest potential in New England.

**Figure 1: Connecticut's Class I Resource Mix[20]**

[19] Vermont does not have a formal RPS; its Sustainably Priced Energy Enterprise Development program promotes renewables to meet all energy growth by 2012; for a detailed comparison of New England RPS Eligibility Requirements, see Appendix II Eligibility White Paper at p. 7.

[20] DEEP RPS Database

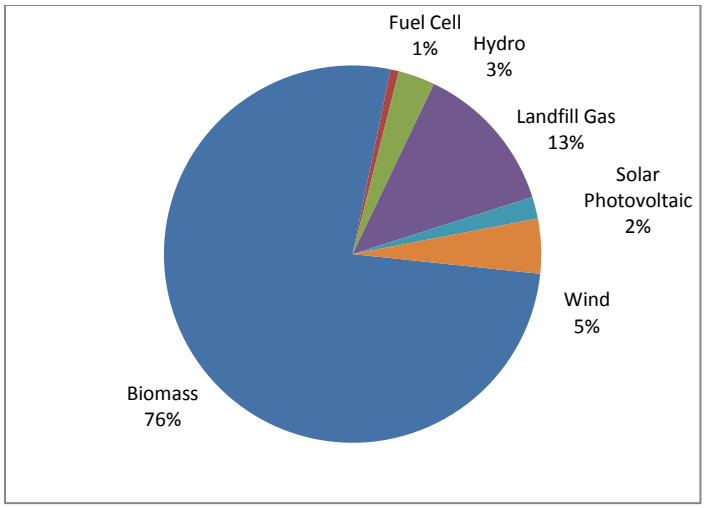
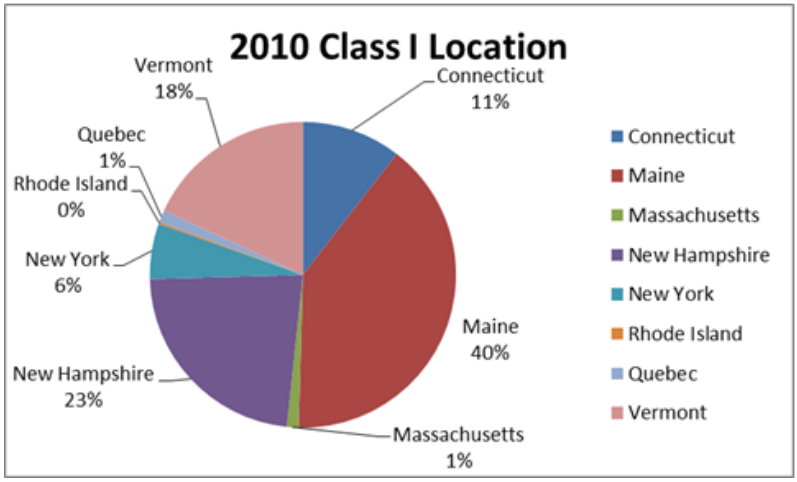



**Figure 2: Location of Resources Filling Connecticut's Class I Requirement[21]**



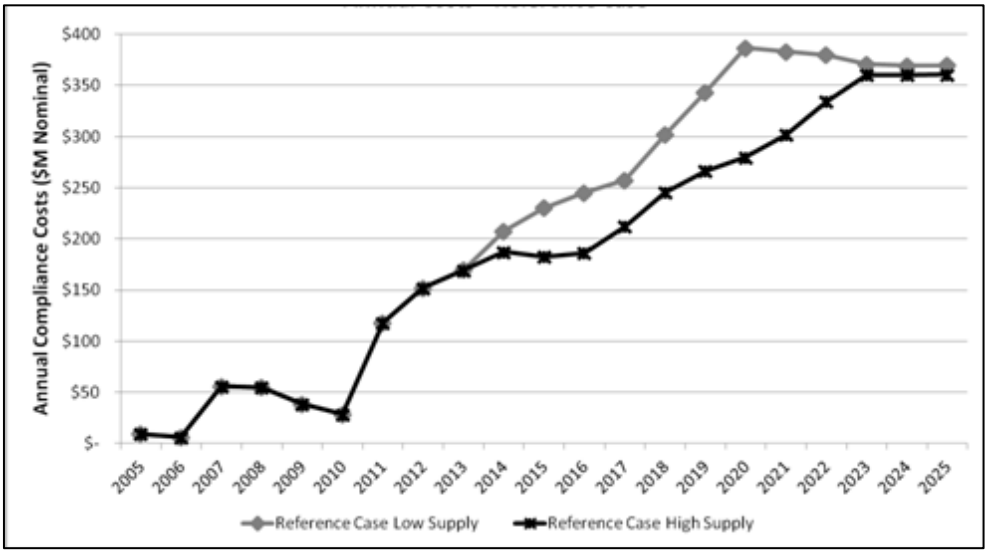

## Class I Compliance Costs

The cost of meeting the Class I RPS has grown in-sync with the annual increase in the Class I requirement. The investment cost in Class I renewables was $151.8 million in 2012. As the Class I RPS requirements increase from 10% in 2013 to 20% in 2020 DEEP estimates that the annual cost of Class I compliance under the current rules could increase to approximately $380 million in 2022 as a result of higher RPS requirements and higher REC prices, potential future

[21]DEEP RPS Database

alternative compliance payments, and the cost of supporting in-state renewable energy programs.

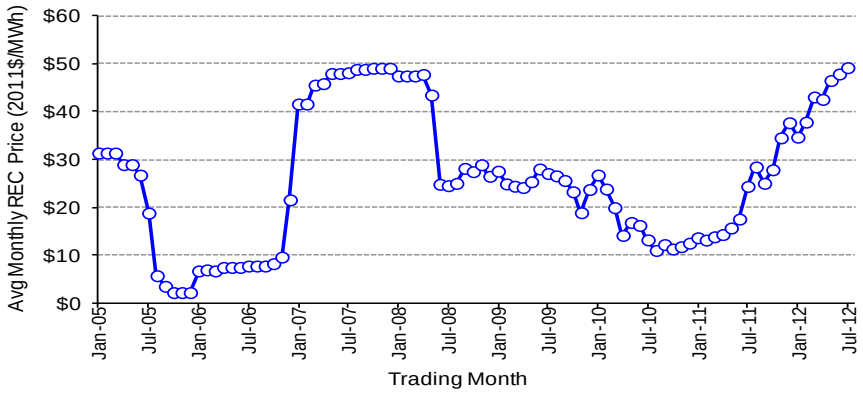
**Figure 3: Connecticut's Annual Class I Compliance Cost – Historic and Reference Case** [22]




REC prices have fluctuated over the years due to market forces and legislative changes to resource eligibility. The supply of renewable power has grown each year to meet the increases in demand without sustained shortages or REC prices reaching the penalty level. More recently, however, the Class I market has swung from surplus into a modest near-term shortage. Class I REC prices have increased from less than $20/MWh in July 2011 to nearly $50/MWh by July 2012. This shortage is expected to last several years until new supply increments come on line [23]

[22] Sustainable Energy Advantage, LLC (SEA) Analysis
[20] SEA Analysis

**Figure 4: Connecticut Class I REC Prices[24]**




*Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the current or nearest future compliance year traded in each month.*

Escalating RPS requirements are also mandated in each of the other New England states except Vermont (Table 2). The higher RPS requirements significantly raise the regional demand for Class I resources over the next ten years. DEEP estimates that REC prices should decline from current levels during the 2015 timeframe, but will then rise because of increasing regional RPS requirements that will require additional supply not currently under development throughout the region. That need for new supply and the long timeframes required for projects in the development pipeline increase the risk of a shortage of Class I resources between 2019 and 2022. Under constrained conditions the price of Class I RECs could increase to levels approaching the Connecticut ACP level of 5.5 cents/kWh.

**Table 2. Class I-Equivalent RPS Targets in New England as a Percentage of Load[25]**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|
| CT Class I | 9.0 | 10.0 | 11.0 | 12.5 | 14.0 | 15.5 | 17.0 | 19.0 | 20.0 | 20.0 |
| ME Class I | 5.0 | 6.0 | 7.0 | 8.0 | 9.0 | 10.0 | 10.0 | 10.0 | 10.0 | 12.5 |
| MA Class I | 7.0 | 8.0 | 9.0 | 10.0 | 11.0 | 12.0 | 13.0 | 14.0 | 15.0 | 20.0 |
| NH Class I & II | 3.2 | 4.2 | 5.3 | 6.3 | 7.3 | 8.3 | 9.3 | 9.9 | 10.8 | 15.3 |
| RI | 4.5 | 5.5 | 6.5 | 8.0 | 9.5 | 11.0 | 12.5 | 14.0 | 14.0 | 14.0 |

[24] SEA analysis, "Renewable Energy 101 Training" slide deck

[25] 2012 Connecticut Integrated Resource Plan, Appendix D-6, Figure 4

To inform this study, DEEP developed two "reference case" scenarios to estimate the future availability of Class I supply and its associated costs. One reference case modeled a "Low Supply" future, and the other modeled a "High Supply" future. Each reference case projects available supply considering the *lesser* of (1) what could be produced by the probability-de-rated renewable energy development pipeline, or (2) the current statutory availability of future long-term power purchase agreements (PPAs) in New England states. In each case, supply and demand are projected for the region and for each individual state, while considering state differences in eligibility. When the availability of projected supply falls short of demand, that gap must be met by either additional supply not in the current development pipeline, or (if such additional supply is insufficient) result in a risk of shortage and ACP costs. As would be expected, the Low Supply scenario results in an earlier onset of the need for additional supply, and higher cost of compliance, than the High Supply scenario.

Key assumptions common to both reference cases include: 363 MW from the Cape Wind development in Massachusetts, which is the amount currently under long term contracts; a common forecast of eligible supply imports into New England over existing transmission ties from adjacent control areas; no expansion of existing transmission ties in those adjacent control areas; no incremental NESCOE regional coordinated procurement for long-term renewable energy contracts beyond what is envisioned under current statutes; and common eligibility and performance assumptions for the existing biomass fleet.

The primary differences between the two reference cases are as follows. The Low Supply reference case assumes that:

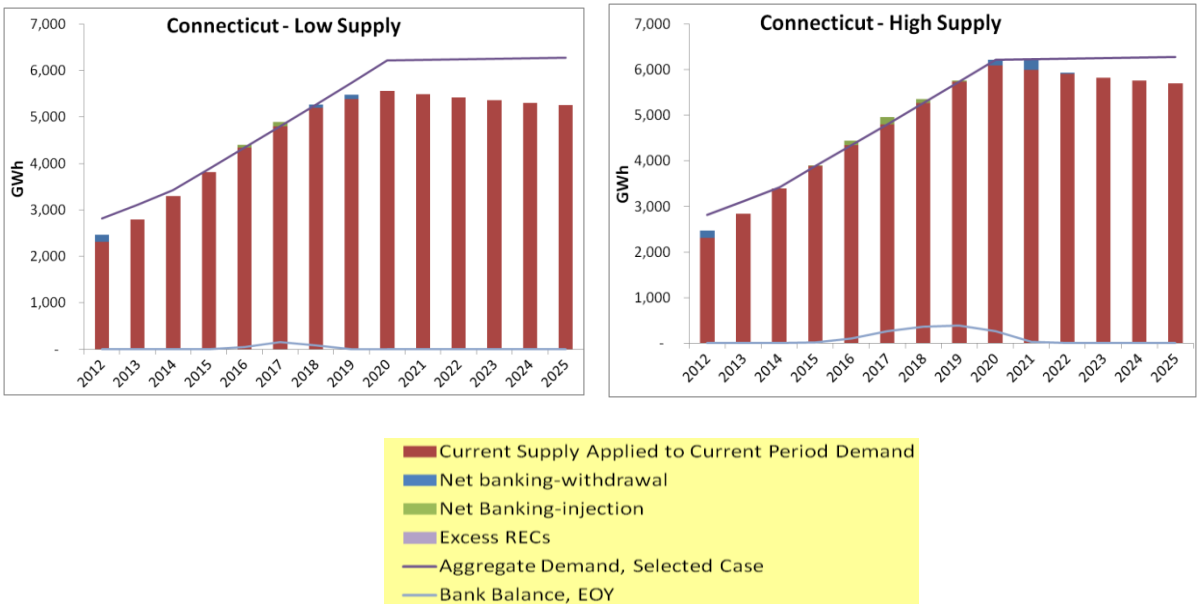
- Existing policies and programs continue unchanged
- Resources currently planned are built and no additional long-term contracts or new transmission upgrades in the region occur.
- Costs are impacted by an assumed extension of the Federal Production Tax Credit through 2014 followed by a phase-out by 2018.

As a result of these assumptions, the Low Supply scenario limits the amount of wind power that could be brought to market from remote locations in Maine, thereby contributing to the potential shortage of Class I resources estimated to occur in 2019. The High Supply scenario is more optimistic. In that scenario, DEEP assumes:

- New transmission is added, allowing more wind facilities to deliver their power to customers outside of Maine while securing capacity revenues.

- Rhode Island will add 450 MW of offshore wind in federal waters.
- The supply of landfill methane by pipeline available to meet the Connecticut Class I demand is assumed to be twice as large as that under the low supply future
- Other New England states will adopt additional policies intended to boost the success of their respective in-state RPS supplies.
- Costs of renewables are lower due to an assumed extension of the Federal Production Tax Credit through 2015, followed by a phase-down to 50% of its current value by 2020 (extended at that level indefinitely thereafter).
- State-sponsored renewable resources will receive an exemption in the forward capacity market (FCM) from the minimum offer price rule (MOPR), which is set for implementation in the 2017-2018 timeframe.[26]

**Figure 5: Reference Case - Low Supply vs. High Supply**




The reference cases offer the following projections of Connecticut's renewable energy future. Over the next ten years, the share of Connecticut's Class I requirement provided by in-state renewable resources will increase as Project 150 facilities and projects developed in response to ZREC/LREC and other policies (detailed earlier in this study), begin operation. Generation from

[26] Note, however, that on February 12, 2013, FERC concurrently issued an Order on ISO-NE's FCM compliance filing and an Order denying NESCOE's Section 206 Complaint in relation to a renewable exemption. The effect of these two Orders is that ISO-NE's implementation of buyer-side mitigation in the FCM (also known as the Minimum Offer Price Rule or MOPR) without an exemption for state-sponsored renewable resources will proceed for the 2017-2018 timeframe. Without such an exemption, new renewable resources are unlikely to receive revenues from the FCM, and New England ratepayers will not receive capacity credit for any new renewable resources through the FCM.

these programs will increase from a trivial quantity in 2012 to 4.6 % of the total eligible load in 2020. Importantly, this will represent approximately 46% of the incremental increase necessary to meet higher RPS requirements between 2012 to 2020.

While in-state facilities will help Connecticut meet its RPS requirements, the renewable resources most available in Connecticut—solar and fuel cells—can be relatively expensive compared to the least cost Class I renewable energy options available regionally. However, these in-state projects bring local economic, environmental, and human health benefits to the state that do not accrue from out-of-state sources. By 2020 in-state programs are expected to produce approximately 23% of the Class I RPS requirement, but are estimated to account for 32% to 45% of the total cost.

Under the reference cases, it is anticipated that much of the remaining regional Class I requirement will be met by wind resources located in northern New England or offshore. In order to meet Connecticut's growing RPS requirements and those of other New England states, it is likely that long-term contracts will be needed to finance the construction of generation facilities and the accompanying transmission needed to move that power to load centers in Massachusetts and Connecticut. Additional in-state facilities could also be developed, but this would add additional costs to the reference case scenarios analyzed. If the cost of solar and fuel cells declines as expected over the next few years, this option may become more favorable as a way of meeting our RPS demand in the post-2020 timeframe.

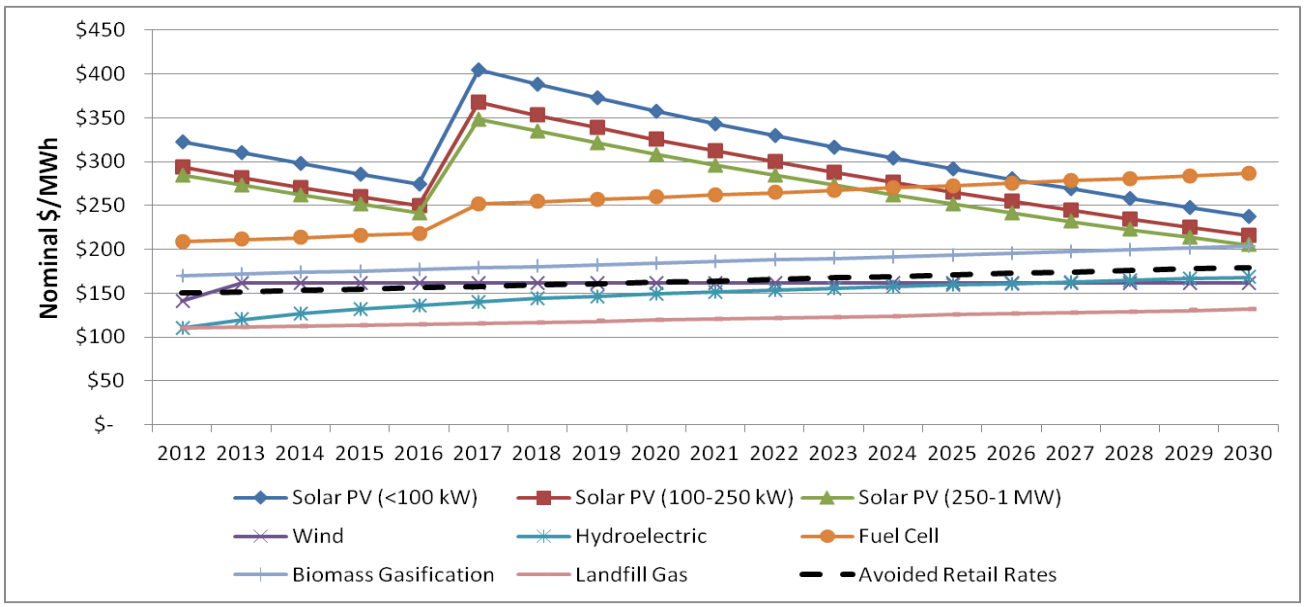
The results of DEEP's analysis indicate that a potential shortage of Class I resources may not occur as early as estimated in the 2012 Integrated Resources Plan (IRP), issued by DEEP in June 2012. In the 2012 IRP, a shortage of Class I RECs was projected to occur in the 2017-2018 timeframe, compared to this study's analysis of that occurring in 2019 under the low supply scenario and 2022 under the high supply case. Although the IRP estimated the annual cost of the Base Case scenario in 2022 to be approximately $445 million in 2012 dollars, the updated analysis in this study concludes that there could be a $334 million to $380 million price tag if other changes are not adopted. These changes are the result of new analysis in this study that incorporates the latest information on potential projects in the region, their cost and likelihood of success, and reductions to RPS targets in New Hampshire. The updated analysis also takes into account (1) the availability of new long-term contracting policies adopted since the IRP was issued, that support financing of regional projects, and (2) a detailed forecast of the ZREC and LREC programs and (3) methodological differences (e.g, banking of surplus, state-by-state differences) that address market dynamics that were not not included in the IRP. While the

estimated cost of Class I compliance under this study is lower than predicted by the 2012 IRP, these costs are still significant and merit continued evaluation of refined options that could help to reduce costs to ratepayers.

## Options to Reduce Class I Compliance Costs

One way to reduce the costs of compliance with the Class I requirement is to increase the available supply of Class I resources. Under the current RPS structure, the principle renewable options that are eligible for Class I and currently available are out-of state-wind, in-state solar, and fuel cells. Large hydroelectric power is also currently available, but is not eligible for Class I under the existing RPS structure.

**Figure 6: Underlying Cost Projections: LRECs & ZRECs**[27]




Connecticut benefits the most, in terms of employment and economic development, from development of in-state resources. In-state facilities result in a growth of manufacturing and installation employment for renewable energy systems. Behind the meter projects, such as solar and fuel cells, help customers reduce their electric bills—increasing ratepayers' expendable income and making local businesses more competitive. In-state projects have an economic multiplier effect as a portion of these customer savings are then spent on local goods and services.

[27] SEA Analysis

While the costs of renewable energy, particularly solar and wind, have declined dramatically since enactment of Connecticut's RPS they are still more expensive than anticipated when those out-year RPS targets were established. While the Alternative Compliance Payment was set to provide a guarantee to financers of renewable developers, achieving compliance through significant use of the ACP was never the goal of the RPS.

Given the anticipated lag in renewable development, concerns about the resulting costs of meeting the RPS requirements within the current RPS structure have prompted analysis of other options that achieve the energy, environmental and economic development objectives of the RPS at a lower cost to Connecticut ratepayers. DEEP has examined two policy options that could be used to reduce the cost of complying with the current RPS while still advancing the fundamental RPS goal of reducing the negative impacts of traditional generation. One option is to expand the eligibility of Class I resources. DEEP has examined the current eligibility requirements for Class I resources and has compared them to other New England states with an eye to expanding eligibility where appropriate to increase the supply of Class I. In addition, DEEP has evaluated more substantial changes that would allow a portion of Class I to be met by large hydroelectric power. There is significant potential for new large hydro development (greater than 30MW) outside of New England. New hydro could be used to help meet Connecticut's energy needs as well as the environmental goals of the RPS and the Global Warming Solutions Act. Inclusion of these resources offers many benefits, but requires special thought and consideration so as not to undermine other goals of the state's RPS. The analysis of these options and resulting recommendations are presented below.

## Modifications to Existing Class I Eligibility

Table 4a-c compares the qualifying technologies for each of the RPS Classes for the five New England states that have RPS requirements. All of the New England states qualify solar photovoltaic, ocean thermal, wave, tidal, and wind as Class I sources. Other technologies such as biomass, fuel cells, and hydro are also common, but the definition and qualifications for these technologies vary substantially from state to state. Connecticut is unique with its inclusion of fuel cells that utilize natural gas as a Class I resource, and cogeneration and energy efficiency as Class III sources. Connecticut is the only New England state to allow energy efficiency to qualify as a resource to meet any RPS requirements. Connecticut is also the only state to allow legacy supply, requiring no vintage threshold to limit Class I eligibility to new generation.

**Table 4a: Comparison of Regional Eligibility for Connecticut Class I-Eligible Resources**

| Resource Type | CT Class | MA Class | RI Class | NH Class | ME Class |
|---|---|---|---|---|---|
| Solar | 1 | 1 | 1 | 1 | 1 |
| Wind | 1 | 1 | 1 | 1 | 1 |
| Fuel Cell - Natural Gas | 1 | Ineligible | Ineligible | Ineligible | Ineligible |
| Fuel Cell - Renewable Source | 1 | 1 | 1 | 1 | 1 |
| Landfill Methane Gas | 1 | 1 | 1 | 1 | 1 |
| Ocean Thermal | 1 | 1 | 1 | 1 | Ineligible |
| Wave | 1 | 1 | 1 | 1 | Ineligible |
| Tidal | 1 | 1 | 1 | 1 | 1 |
| Hydro | 1 | 1 | 1 | 1 | 1 |
| Biomass | 1 | 1 | 1 | 1 | 1 |
| Geothermal Electric | Ineligible | 1 | 1 | 1 | 1 |
| Anaerobic Digestion | Ineligible | 1 | 1 | 1 | Ineligible |
| Marine Hydrokinetic | Ineligible | 1 | Ineligible | Ineligible | Ineligible |
| Landfill Methane Gas by Pipeline[28] | 1 | 1[29] | Ineligible | Ineligible | Ineligible |

**Table 4b: Comparison of Regional Eligibility for Connecticut Class II-Eligible Resources**

| Resource Type | CT Class | MA Class | RI Class | NH Class | ME Class |
|---|---|---|---|---|---|
| Trash to Energy | 2 | 2B | Ineligible | Ineligible | 2 |
| Biomass | 2 | 2A | Ineligible | 3 | 2 |
| Hydro | 2 | 2A | Ineligible | 4 | 2 |

**Table 4c: Comparison of Regional Eligibility for Connecticut Class III-Eligible Resources**

| Resource Type | CT Class | MA Class | RI Class | NH Class | ME Class |
|---|---|---|---|---|---|
| Combined Heat & Power | 3 | APS[30] | Ineligible | Ineligible | 2 |
| Waste Heat Recovery | 3 | Ineligible | Ineligible | Ineligible | Ineligible |
| Energy Efficiency | 3 | Ineligible | Ineligible | Ineligible | Ineligible |
| Demand Response | 3 | Ineligible | Ineligible | Ineligible | Ineligible |

With regard to other potential Class I technologies DEEP finds the following.

[28] This can be from a source outside New England, from specified locations when accompanied by an approved contract path for pipeline delivery.

[29] Proposed change under current rulemaking to add to eligible resources.

[30] CHP is included in MA's alternative energy portfolio standard or APS. CHP for class I is a subset of biomass eligibility (not explicit, but the de facto requirement of the high biomass conversion efficiency requirement)

While geothermal and solar thermal qualify as Class I resources in several New England states, DEEP recommends that the electricity produced by geothermal steam generation be qualified as a Class I resource. The potential for this technology, however, is very limited in Connecticut. DEEP does not recommend that the definition of Class I be expanded to include geothermal heat pumps or solar thermal. Geothermal heat pumps already qualify as a Class III resource. DEEP believes that the RPS is intended to encourage the development of renewable electric generation or electric energy saving technologies. Geothermal heat pumps provide heat for space heating and may also provide air conditioning. On the heating side, most of the savings are for gas and oil since only 10% to 15% of Connecticut residents heat their homes with electricity. Solar thermal is primarily used as an alternative for heating hot water and in some cases space heating and therefore is also a technology that primarily saves oil and gas. DEEP therefore does not recommend solar thermal be included as a Class I resource.

Several states include anaerobic digesters as a Class I resource but it is not specifically mentioned in Connecticut's RPS legislation. DEEP recommends that anaerobic digesters be specifically qualified as a Class I source in Connecticut.

Connecticut includes "methane from landfill gas" as a Class I resource, as do each of the other New England states. However, there is no definition of landfill gas in the Connecticut legislation. DEEP believes that methane should not be required to actually come from a landfill. PURA (the former Department of Public Utility Control) has interpreted the statute broadly, but it would be prudent to clarify that all biologically-derived methane/biogas from sources such as yard and plant matter, food waste, animal waste and sewage sludge is eligible as a Class I source.

The definition of eligible hydroelectric generation varies significantly among states; Connecticut's is the most stringent for Class I qualification. Under Connecticut General Statutes Section 16-1 (a)(26), a hydro project must be built after 2003, be run-of-river, and be less than 5 MW to qualify as Class I in Connecticut. Much larger projects can qualify in other states. In Massachusetts and Rhode Island, hydro projects up to 30 MW that are certified by the Low Impact Hydro Institute qualify as a Class I source, (up to 100 MW qualifies in Maine). DEEP recommends that the eligibility definition should be modified to allow post-2003 hydro projects up to 30 MW that meet the certification standards of the Low Impact Hydro Institute to qualify as a Class I source in Connecticut. Increasing the project size and updating the certification standards would be more consistent with other New England states and may expand the supply of Class I resources available to help Connecticut obtain its RPS requirement. DEEP does not believe that many completely new hydro facilities will be developed in New England in the

future, but this modification could create an incentive for some existing sites in the 5 MW to 30 MW range to be refurbished or increase their efficiency. As a part of this Study, DEEP requested that its consultant, Sustainable Energy Advantage, LLC (SEA) conduct a comprehensive analysis of Class I eligibility requirements. A detailed review of these eligibility considerations is presented in the whitepaper entitled "Eligibility Issues and Options Connecticut Class I RPS," which is included in Appendix II.

Connecticut is the only state that allows legacy renewable facilities that were built prior to electric restructuring to qualify as Class I sources. As a result, Connecticut's Class I RPS has become a sink for these sources. Consequently, as compared to other states in the region, Connecticut ratepayers have been providing disproportionate support for keeping the region's legacy fleet running. Currently there are approximately 275 MW of biomass and 80 MW of landfill gas eligible in Connecticut—much of it located out-of-state. In 2010, Connecticut relied on biomass and landfill gas to meet 89% of its Class I REC requirements. These facilities are generally over 20 years old. The concern related to subsidizing these legacy facilities is that ratepayer support might be better spent to finance the development of new cheaper, cleaner, renewable resources. Class I is currently short in supply, resulting in high REC prices in the near term. In 2010, Connecticut relied on biomass and landfill gas for meeting a combined 89% of its Class I REC requirements. However, immediate sudden changes to the eligibility requirements that could remove over 350 MW of capacity from Class I eligibility in the near term could cause REC costs to remain high for years, and this could have large impacts beyond just the RPS markets. Eliminating REC revenues for biomass and landfill gas projects might make these facilities uneconomic to operate. The potential immediate retirement of 350 MW in the absence of new renewable development to supply Connecticut's Class I requirement could adversely impact capacity markets, and potentially electric rates and reliability.

DEEP believes that a careful, deliberate transition away from a reliance on legacy biomass facilities is appropriate particularly if timed in a way that makes it possible for other Class I resources to be developed and/or that allows large-scale hydro is allowed to meet the region's needs for clean renewable resources at a reasonable cost.

### Contracted Class I Sub Tier with Large Hydro Eligible

As directed by Section 129 of Public Act 11-80, DEEP examined a variety of alternatives that could potentially reduce the overall cost of RPS compliance while simultaneously maintaining the policy objectives advanced by Connecticut's RPS. In doing so, DEEP investigated the full

range of options for including large scale hydro as part of Connecticut's definition of Class I resources. Large hydro (over 5 MW) that is not run-of-the-river is not currently qualified as a Class I resource in Connecticut, regardless of when it was built. With the exception of Maine, none of the New England states allow large hydro (over 30 MW) to fulfill RPS requirements. One option explored in this review was to allow large-scale hydropower to meet a portion (contracted tier) of Class I that would not be eligible in the Class I NEPOOL GIS REC market. It may be possible to contract for Canadian hydro delivered into New England at approximately the projected market price of power while paying little or no renewable premium.

The primary objectives of the proposed Contracted Class I Tier are to advance clean energy renewable goals, reducing the cost of meeting the RPS while providing similar environmental benefits. This study examined the following issues to determine how to best achieve the above objective:

- Structure of the Tier
- Geographic location
- Ability to deliver energy into the program's control area
- Vintage (i.e. resources brought online after the creation of the RPS or some other temporal milestone)
- Contracting mechanisms
- Potentially available supply and transmission capacity
- Environmental impact

The results of this feasibility analysis are contained in a white paper entitled, "Incorporating Substantial Low-Cost Renewable Energy (Large Hydro-Eligible) Contracts into a Connecticut Class I RPS Sub-Tier," (See Appendix I). DEEP has evaluated these issues along with the pros and cons of each.[31]

DEEP, along with the consultants at SEA, considered a number of scenarios to evaluate the impact of allowing large-scale hydro to fill a portion of the Class I RPS requirements. Presented below are four scenarios to illustrate the impact of this range of policy options. The analysis

[31] A summary can be found at the end of this report on p. 42.

examined the impact of different levels of hydro under the existing Class I requirements as well as options which raised the RPS requirements after 2020. The reference case scenario illustrates the current RPS policy and expected contributions from existing programs.

### Contracted Sub Tier Scenarios: Descriptions

Scenario 1 establishes the combined Market and Contracted Class I RPS target at 20% by 2020, but adds a new Contracted (hydro) Tier that totals 5% of RPS eligible load. The Contracted Tier ramps up from an initial amount of 2.5% of load in 2014 to 5% by 2020. The traditional Class I (Market Tier) target peaks at 15% in 2020.

Scenario 2 establishes the combined Market and Contracted Class I RPS target at 20% by 2020, but adds a new Contracted (hydro) Tier that reaches 10% of eligible load, dropping the requirement from traditional sources to 10% by 2020. The Contracted Tier ramps up from 5% in 2014 to 10% by 2020. The traditional Class I (Market Tier) target peaks at 10% in 2013 and remains flat thereafter.

Scenario 3 extends Scenario 1, by establishing the combined Market and Contracted Class I RPS target at 20% by 2020 and 25% by 2025. A Contracted (hydro) Tier that ramps up from 2.5% in 2014 to 7.5% of load by 2025 is added. The traditional Class I (Market Tier) target reaches 15% by 2020 and 17.5% by 2020.

The most aggressive approach is represented in Scenario 4. It establishes the combined Market and Contracted Class I RPS target at 25.5% by 2020 and 30% by 2025. The ramp up of the Market Class I Tier is slowed to reach 20% by 2025 instead of 2020, with reductions replaced, and supplemented, by a Contracted (hydro) Tier starting at 2.5% in 2014 ramping up to 10% of eligible load by 2025.

**Table 5: Scenario Summaries**

| RPS Demand Scenario | Market Tier Target in 2020 | Market Tier Target in 2025 | Contracted Tier |
|---|---|---|---|
| **Reference Case**<br>*20% by 2020* | 20% | 20% | None |
| **Scenario 1**<br>*20% by 2020*<br>*5% Contracted* | 15% | 15% | 2014-2020 Ramp from 2.5% to 5% |
| **Scenario 2**<br>*20% by 2020* | 10% | 10% | 2014-2020 Ramp from 5% to 10% |

| | | | |
|---|---|---|---|
| *10% Contracted* | | | |
| **Scenario 3**<br>*25% by 2025*<br>*7.5% Contracted* | 15% | 17.5% | 2014-2025 Ramp from 2.5% to 7.5% |
| **Scenario 4**<br>*30% by 2025*<br>*10% Contracted* | 17.5% | 20% | 2014-2025 Ramp from 5% to 10% |

To compare resource options to meet any projected shortfall, DEEP estimated the over-market cost of each scenario, for a 100 MW block of power in 2025 (Table 6). A 100 MW block represents 876 GWh or approximately 14% of Connecticut's Class I RPS requirement in 2020. DEEP estimates that it would cost approximately $88 million annually in 2025 for a mix of in-state solar and fuel cells. This compares to $48 million annually for the worst-case scenario spot market risk – that is, prices under shortage conditions that would approach the $55/MWh ACP; $22 to $46 million for New England States Committee on Electricity (NESCOE) Procurement (regional wind under long-term contracts); and potentially $0 for large hydro under a contracted sub-tier. In making this comparison, DEEP assumed that no premium would be paid above the market price for a contracted block of large scale hydropower, and that the 100 MW could be flowed over existing transmission lines.

**Table 6: Cost Sensitivities for Filling 100 MW Block by 2025, Single Year Compliance Cost (above market)**

| Scenario | Supply Case | Spot (ACP Risk)[1] | NESCOE Procurement[2] | Additional In-State Programs[3] | Contracted Tier[4] |
|---|---|---|---|---|---|
| Reference | High Supply | $48,180,000 | $44,564,748 | $88,767,797 | $0.00 |
| Reference | Low Supply | $48,180,000 | $46,188,852 | $88,767,797 | $0.00 |
| Scenario 3 | High Supply | $48,180,000 | $22,363,252 | $88,767,797 | $0.00 |
| Scenario 3 | Low Supply | $48,180,000 | $46,173,084 | $88,767,797 | $0.00 |
| Scenario 4 | High Supply | $48,180,000 | $43,697,508 | $88,767,797 | $0.00 |
| Scenario 4 | Low Supply | $48,180,000 | $45,826,188 | $88,767,797 | $0.00 |

1: = 100 MW * 8760 * $55 (ACP)
2: = 100 MW * 8760 * Price Forecast in 2025
3: In-State Program methodology → LREC/ZREC/Res Solar @ same total budget ratios w/ goal seek to reach 100 MW of capacity by 2025
4: Assumes that contract will be at no premium to market

As observed in Table 6, wind provides the greatest potential and lowest cost of the Class I eligible resources available in New England. This is represented by the proposed NESCOE procurement, which is assumed to be regional wind that is currently at the margin and needs a long-term contract to be viable in the market.

The analysis demonstrates that significant savings are possible by allowing large-scale hydro to fill a portion of the Class I requirement. Large hydro is the least cost option, followed by regional wind, with in-state resources being the most expensive. There are, however, other costs and benefits associated with these resources that must be considered.

None of these renewable resources produce emissions. There are differences in the time and magnitude that these resources produce power, but to the extent that they replace traditional generation they will each have the same ability to reduce harmful emissions such as $CO_2$, $NO_2$ and $SO_x$. The environmental impacts associated with building and transmitting power from distant hydro facilities in Canada or wind turbines in Maine, however, are greater than the benign impact of rooftop solar installations and fuel cells located in Connecticut.

The 2012 Integrated Resource Plan included estimates of the macroeconomic and employment impacts of various alternative resource strategies. The Department of Economic and Community Development (DECD) assisted in this effort by modeling the impact of additional energy resource investments in renewable resources and energy efficiency on employment, state GDP and state revenues. DECD developed its analysis using an input-output model, developed and maintained for the Connecticut Center for Economic Analysis, by Regional Economic Model, Inc. (REMI). The REMI simulations estimated the annual employment impact, over a 20-year period, of an annual $10 million increase in investments in fuel cells and solar/small wind projects in Connecticut. REMI also simulated the impact of changes in electric rates of $10 million and $100 million. DEEP scaled these REMI results to the investment and rate impacts of the alternative RPS scenarios to estimate the annual impact on in-state jobs.

Table 7, below, shows the employment impact of each option, including direct, indirect and induced impacts. The analysis assumes out-of-state wind as the baseline. Importing 100 MW of large hydro would have a downward effect on electric rates, because large-scale hydro is the lowest cost option. In this analysis it is assumed that hydro will be purchased at the market price of power with no renewable premium. The cost of large hydro is estimated to be $48.2 million less than the estimated cost of Spot Class I power (out-of-state wind) in 2025. The

impact of lower electric rates associated with the large hydro also results in an increase of 295 jobs annually as consumers spend their savings on other in-state goods and services.

**Table 7: Projected Employment Impact of Class I Generation Options**

| Employment Impact of Class I Generation Options (Job Creation) | | | |
|---|---|---|---|
| | Baseline-wind | In-state Renewable | Large hydro |
| Rate Impact | 0 | -309.2 | 295.4 |
| In-state Spending | 0 | 979.6 | 0 |
| Total Job Impact | 0 | 670.4 | 295.4 |

In-state renewable investments in solar and fuel cell systems result in $43 million in higher rates than the baseline wind scenario in 2025. DEEP estimates that higher rates associated with in-state renewable development would result in 309 fewer jobs annually than the wind option, however, this would be more than offset by an increase in employment due to the manufacturing and installation of solar and fuel cell systems. Three fuel cell manufacturing companies are located in Connecticut. Other Connecticut companies manufacture or assemble components used in these systems. DEEP estimates the direct impact of higher in-state spending would result in the addition of 980 jobs annually. The net result would be the addition of 670 jobs annually from the addition of 100 MW of in-state Class I renewable generation.

## Contracted Sub Tier Scenarios: Savings

Each of the hydro options is projected to result in a lower overall cost than the Reference Case scenario. In these scenarios, large hydro is assumed to displace a portion of Class I resources at no premium (i.e., the state would acquire and retire the associated RECs). In addition, the price of RECs declines due to a lower regional demand for Class I RECs. This combination of fewer REC purchases and lower REC prices decreases total costs in all of the hydro options when compared to the Reference Case.

Figure 8: Annual Compliance Costs - Low Supply vs. High Supply[32]

[32] Id.

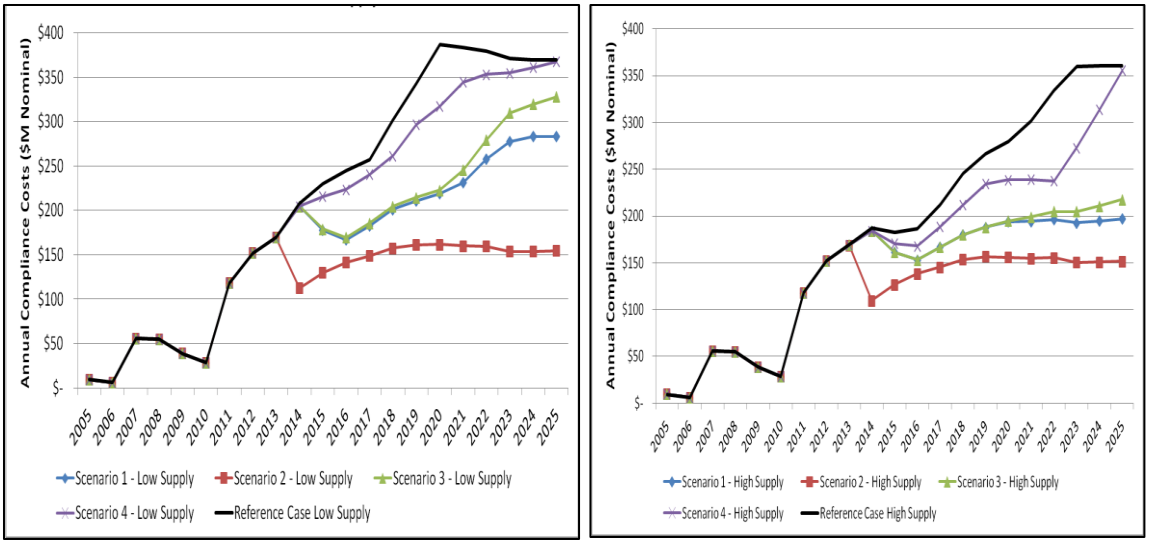



**Figure 9: Net Present Value of Compliance Costs (2013-2025)**

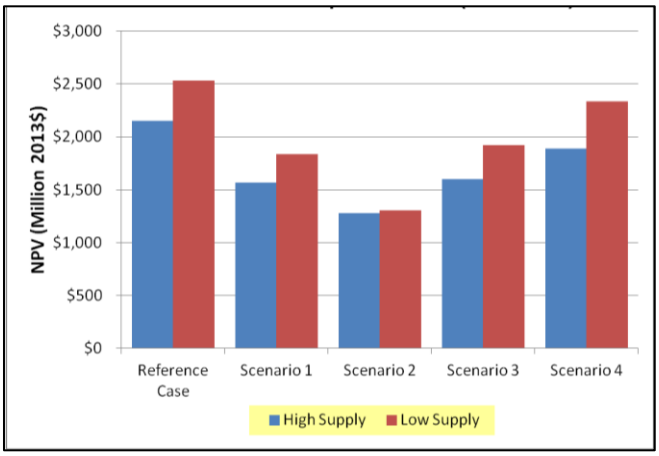
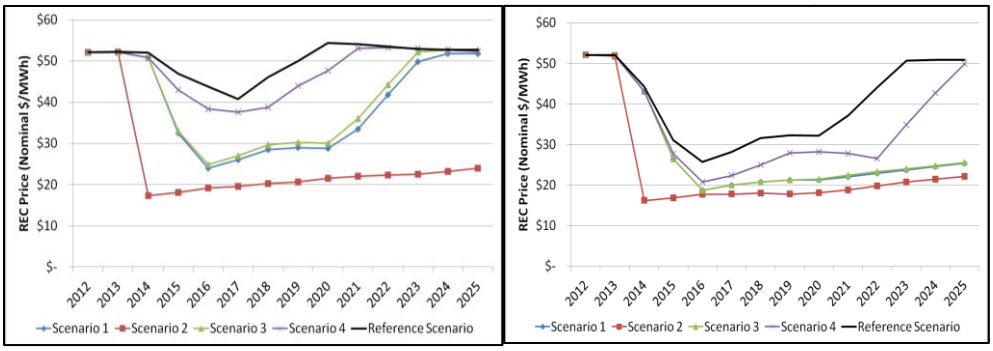



**Figure 10: REC Price Forecast ($/MWh) - Low Supply vs. High Supply[33]**

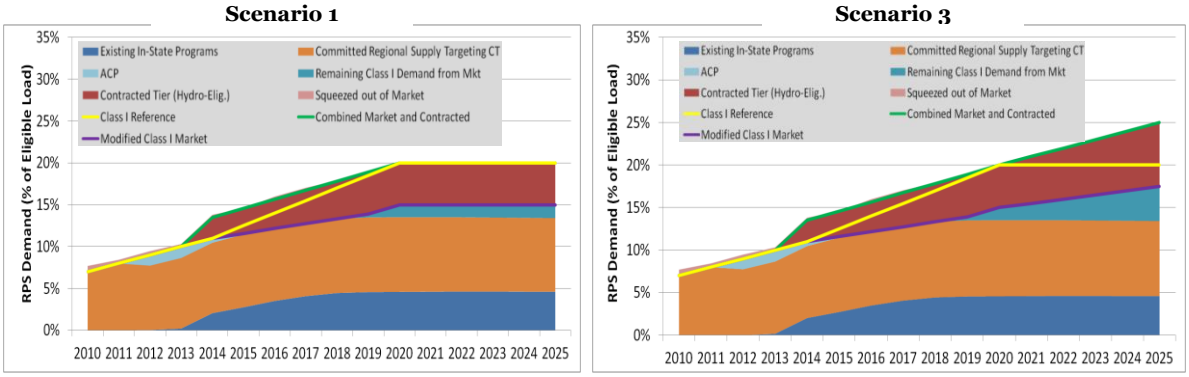



33 SEA Analysis, "CT RPS Compliance Cost Scenario Analysis," slide deck

The savings under Scenario 1 and 3 are significant. The total cost over the ten year period from 2013 through 2022 for Scenario 1 is estimated to be $1.8 to $2.0 billion compared to $2.4 to $2.9 billion under the reference cases. It is estimated that Connecticut electric ratepayers could save from $578 million to $883 million or $363 million to $573 million on a present value basis under Scenario 1 over the ten year period. Annual savings are estimated to be approximately $122 million to $138 million annually for Scenario 1 in 2022 compared to the High and Low Supply Reference Cases.

The overall cost of Scenario 3 is just slightly higher than Scenario 1 due to the increase in the RPS requirements from 20% in 2020 to 25% in 2025. However, the total cost of Scenario 3 is still considerably less than the Reference Cases. Under Scenario 3, Connecticut electric ratepayers could save from $564-$830 million or $355-542 million on a present value basis over the ten year period from 2013 to 2022. DEEP estimates that savings of $70 million to $138 million annually in 2022, could result from Scenario 3 in comparison to the Reference Cases.

**Figure 11: RPS Demand - Scenario 1 vs. Scenario 3**[34]




A 5% reduction in the Class I RPS requirements in 2020 is approximately 1500 GWH. Contracting for large hydro would avoid the need for approximately 490 MW of wind power at a 35% capacity factor, but would only require 171 MW of transmission capacity if the power was delivered evenly across all hours.

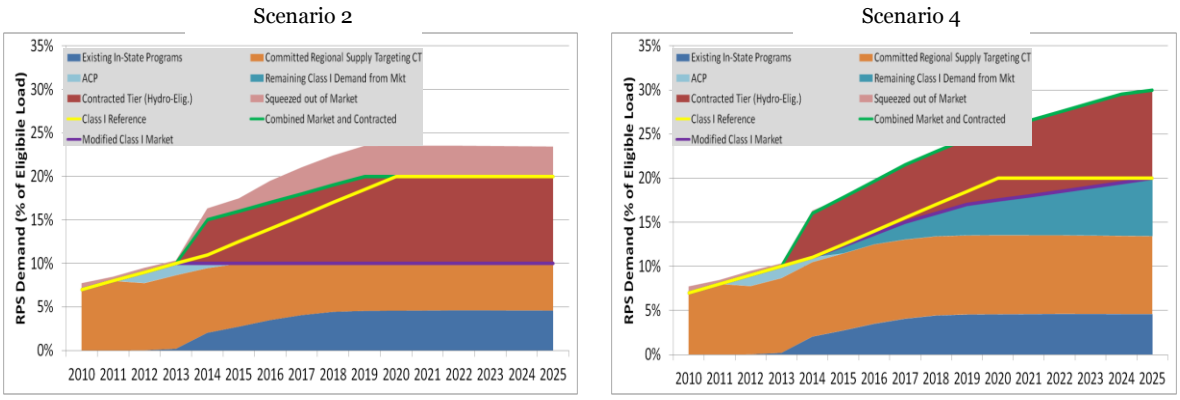
Under these scenarios there is little disruption to existing projects, or those under construction. Demand for the traditional Market Tier continues to grow, which provides adequate demand for the projected supply from Connecticut's existing in-state renewable energy programs. However, a sub tier made up of 5% contracted large-scale hydro by 2020 would take up almost all of the

34 SEA Analysis, "CT RPS Compliance Cost Scenario Analysis," slide deck

incremental RPS requirements not filled by in-state programs, displacing any potential regional resources currently in the development pipeline or that might otherwise be developed in the next five or six years. In Scenario 3, there would be demand for additional resources after 2020, which could be filled with regional or additional in-state Class I resources after. The exact amount of demand for additional Class I resources is unknown as the portions of the RPS that are displaced by large hydro are offset to some degree by tightening the Class I requirements for "legacy" renewable generation and disallowing resources that are counted toward renewable obligations in other states.

Scenario 2 is similar to Scenario 1, but a larger portion of the Class I requirement is allowed to be filled with large hydro. Scenario 2 is also based on the current 20% by 2020 RPS. In this scenario, however, the Contracted Tier ramps up from 5% in 2014 to 10% of the Class I requirement in 2020. This represents 100% of the current incremental growth in the requirements from 2013-2020 which is the equivalent of 1088 MW of wind. The traditional Class I Market Tier peaks at 10% in 2013 and stays at that level through 2020. Of the scenarios analyzed, this Scenario 2 results in both the lowest annual and total cost, but also has the greatest impact on the Class I market, squeezing out existing resources and all new facilities currently under development.

**Figure 12: RPS Demand - Scenario 2 vs. Scenario 4**[35]




Large hydro could be used to meet Connecticut's energy needs without being eligible to receive Class I RECs and would be considered "outside" of the RPS. Allowing large hydro, outside of the RPS, to help meet our energy and capacity needs would reduce prices in the energy and capacity markets. It would not, however, provide the benefit of fewer Class I REC purchases or reduced

35 SEA Analysis, "CT RPS Compliance Cost Scenario Analysis," slide deck

REC prices. Scenario 4, which includes a large hydro Contracted Tier, provides an example of how large hydro, outside of the RPS, could work. In Scenario 4 the Combined Market and Contracted Tier increases from 20 to 25% in 2020 and to 30% by 2025, but only small portion of the Contracted Tier hydro is substituted for existing Class I requirements. The result is little disruption to the Class I market, but also the least savings of the scenarios examined—REC prices would remain high and Connecticut would still be faced with possible supply shortages in the future.

The scenarios analyzed and presented are just a sample of possible approaches that could be taken to meet Connecticut's Class I renewable energy objectives at a lower cost. The mix of resources and the resulting cost to ratepayers varies significantly depending on the approach. If Connecticut maintains current requirements and continues to rely on spot market purchases of RECs, it is likely that that it will be increasingly difficult to meet our RPS requirements, increasing the risk of shortage and payment of the ACP within a decade. To the extent that new resources are deployed, wind from out-of-state sources (which will also require expensive transmission investments) will dominate new capacity additions not provided by existing in-state programs. By taking a more active role in the market, Connecticut can (1) increase the diversity of its electric resources thereby increasing reliability and providing a hedge against future higher fossil fuel prices; (2) reduce harmful greenhouse gas and criteria pollutant emissions; and (3) achieve these benefits without burdening ratepayers with high costs that yield limited benefits.

### Large Hydro Eligibility Criteria and Contact Structure for Contracted Tier

The creation of a new Contracted Class I Tier requires establishing eligibility criteria that differ from the current Class I eligibility requirements for hydroelectric resources, which are: (1) run-of-the-river, (2) 5MW or less, and (3) began operation after July 1, 2003. In addition, the hydro facilities must be located in New England or an adjacent control area including NYISO (New York), Hydro Quebec, and the Canadian Maritimes to qualify as a Class I resource. For a facility to qualify from an adjacent control area the energy must be delivered into the ISO-NE grid.

DEEP recommends no size limit on hydro projects eligible under the contracted tier, but it does recommend maintaining the current vintage threshold of July 2003 in addition to the current geographical and delivery requirements. DEEP also recommends a minor expansion of the geographic eligibility footprint, to allow generation from a contiguous control area to the existing eligibility region as long as it is not interconnected to any other control area. This approach would allow large hydro resources in Newfoundland and Labrador to qualify, which

would increase potential competition. Though unlikely to be cost-competitive in the near term, any Class I resource would also qualify under the "contracted tier." Large hydro resources eligible under the new "contracted tier" would not be eligible for REC credit in the NEPOOL GIS market.

The products purchased and contract duration could vary and therefore DEEP recommends retaining flexibility in these areas. Short-term contracts might be appropriate for existing resources delivered over existing transmission facilities. On the other hand, long term (15 to 20 year) contracts for energy, capacity, and the resource's environmental attributes may be needed to encourage development of new transmission or generation facilities.

DEEP would work with the electric distribution companies to meet the RPS requirements of the contracted tier. DEEP envisions conducting a transparent and competitive process with the help of the EDCs to select the projects to fill the contract tier. Connecticut's EDCs, Connecticut Light & Power (CL&P) and The United Illuminating Company (UI), would sign the contracts and administer them. All of the products would be used to benefit all electric ratepayers. The cost of the contracts would be passed on to electric ratepayers through a fully reconciling nonbypassable charge. Any associated environmental attributes could simply be retired. Any capacity or energy would be sold in the markets with any cost/benefits passed on to all electric ratepayers through the same non by passable rate. A detailed discussion of the pros and cons of the eligibility and contract options is included in Appendix I "(Section 6 Transaction Structure).

### Contracted Sub Tier Scenarios: Conclusion

Connecticut has historically had some of the highest electric rates in the country, therefore any ability to reduce those costs while maintaining the state's commitment to clean energy is a high priority for the Department. In pursuing the Governor's goal of a cheaper, cleaner, and more reliable energy future, the state strives to strike a balance between cost and benefit. For that reason, cost is not the only consideration. In-state economic and job benefits as well as environmental and public health improvements are also important factors in developing the recommendations in this study. Connecticut has committed to a significant program of investment to support in-state renewable development and believes that pursuing a strategy similar to that presented in Scenario 3 would complement these efforts. The portion of Class I to be filled with projects under the long-term "contracted tier" allowances would begin in 2014 and increase to 4.5% in 2020. The Contracted Tier could be filled with either large-scale hydro (greater than 30MW) with no premium, or other low-cost Class I resources. The mix of resources will depend on the contract terms and delivered price to the New England electric grid

for the resource. DEEP is focused on minimizing cost while maximizing support for development of in-state and regional renewable power projects. DEEP further recommends that the Class I requirement be increased to 25% in 2025, and that the Contracted Tier be phased up to 7.5% in 2025. Because considerable uncertainty exists around the cost and terms of long-term contracts with renewable energy projects, DEEP believes that it should be given authority in the immediate future to begin a procurement process for large-scale Class I resources, and soon thereafter large-scale hydro resources to meet the Class I "contracted tier" in conjunction with the authority to participate in a further regional procurement for wind or other Class I resources. Timely clarification of DEEP's authority to conduct such a procurement would enable the state to collaborate with other states in the region, which are moving ahead to contract for the lowest-cost regional renewable supply.

Large hydro could help Connecticut meet some portion of its Class I RPS requirements while mitigating the likelihood of high REC prices or ACP costs. By 2022, the inclusion of large hydro in satisfying RPS obligations could reduce electric rates in Connecticut by $70 million to $138 million annually, which would decrease energy bills and make businesses more competitive. In addition, more hydro power would help Connecticut meet its capacity requirements while adding more clean generation into the New England market, and thereby reducing capacity and energy prices. These savings would infuse money into Connecticut as customers spend a portion of their resulting savings on local goods and services.

Today less than 4% of Connecticut's electricity is generated by hydropower. Increasing that proportion would help diversify Connecticut's power mix and provide some insurance against possible shortages, disruptions, and outages. A long-term hydropower contract could also be structured to create a hedge against unexpected rises in gas prices. To the extent that large-scale hydro generation is allowed to fill a portion of Class I RPS requirements and helps avoid supply shortage and compliance through the ACP, Connecticut's dependence on fossil fuels—particularly natural gas—will be reduced. Lower natural gas demand for electric generation would provide some relief to tight pipeline capacity during peak hours, improving electric reliability. Low-cost hydro generation is suited to meet base load needs but also might provide added value if used to meet peak demands and manage the intermittent output of other renewable energy sources.

DEEP will closely monitor RPS compliance on an ongoing basis and will continue to conduct detailed analyses of the Class I market at the time of each biannual IRP. If Class I projects can provide adequate capacity at reasonable costs to meet New England's growing RPS

requirements later in the decade then DEEP will consider phasing out the eligibility of legacy biomass facilities that began operation before 2003. If, however, Connecticut is not meeting its RPS requirements and REC prices move to the ACP DEEP will consider whether the contracted tier should be expanded to meet our environmental goals at a more reasonable cost for electric Connecticut's electric ratepayers.

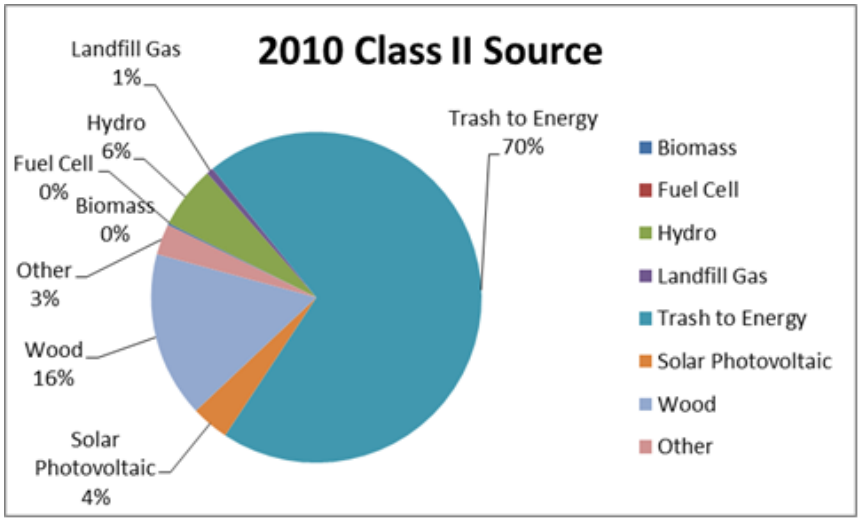
## CLASS II RESOURCES

Pursuant to Conn. Gen. Stat. §16-1(a) (27), Class II renewable energy sources include energy derived from:

- resource recovery facilities;
- a biomass facility that began operation before July 1, 1998, provided the average emission rate for such facility not exceeding 0.2 pounds of NOx per million BTU of heat input for the previous calendar quarter; or
- a run-of-the-river hydropower generating facility up to five megawatts that began operation prior to July 1, 2003.

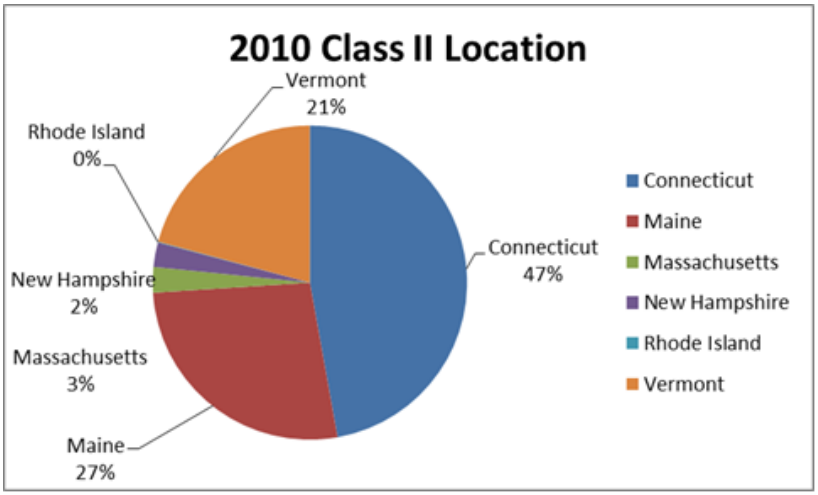
The Class II requirement was initially set at 3% and remains constant through 2020. There are currently 122 generating plants across New England that meet the Connecticut Class II requirement, with a total capacity of 670 MW. More projects could qualify, but do not apply for eligibility because of the low Class II REC prices in Connecticut. The 122 Class II sources include 95 hydropower facilities, 17 resource recovery facilities, and 7 biomass plants. In 2010 70% of the Class II requirement was met with RECs from resource recovery facilities, 16% from biomass, and 6% from hydro that does not qualify for Class I.

**Figure 13: Connecticut's Class II Resource Mix**




As of 2010—the latest compliance period for the RPS—approximately 47 % of RECs used in compliance for Class II were produced from generators located in Connecticut.

**Figure 14: Location of Resources Filling Connecticut's Class II Requirement**

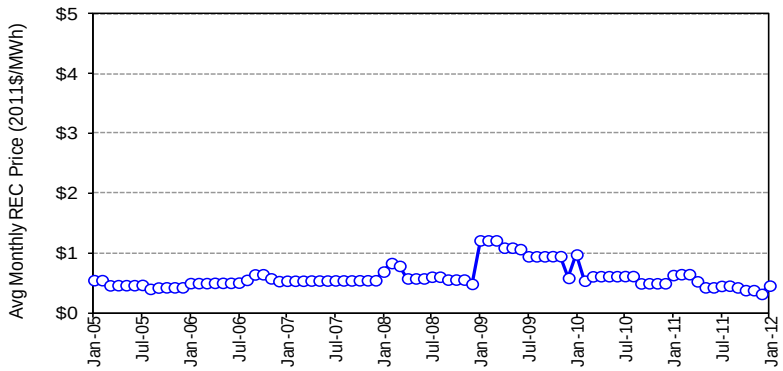



The current supply of Class II resources significantly exceeds the existing RPS requirements. Given the state's electric demand in 2012, the Class II RPS requirement could be satisfied by 900,000 RECs. If it is assumed that the average capacity for Class II generators is 80%, the 670 MW of current Class II resources would equate to 4.7 million Connecticut Class II eligible RECs.[36] This surplus has driven down prices of Class II RECs to less than $5/MWh. DEEP

[36] IRP Appendix D-19

estimates the cost of Class II RECs to be approximately $4.5 million in 2012.[37] These costs should remain about the same through 2020 unless some of the existing facilities retire, thereby reducing the supply of Class II resources.

**Figure 15: Connecticut Class II REC Prices[38]**




*Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the furrent or nearest future compliance year traded in each month.*

In Connecticut, resource recovery facilities comprise the largest source of Class II generation. In 2013 there are eight Class II resource recovery facilities in the state, totaling 223 MW.[39] In addition, Connecticut has 15 Class II hydro generation facilities totaling 16.6 MWs.

Although the generation from these sources may qualify for RECs in other New England states, this capacity has created an oversupply in Connecticut Class II-eligible RECs. Continued low prices for Class II RECs may generate insufficient revenues for in-state resource recovery facilities to remain financially viable.[40]

Connecticut's resource recovery facilities and some of the small hydro facilities began operation in the late 1980's and early 1990's. During that period many of the Class II facilities entered into long-term power purchase agreements (PPAs) to sell their power to CL&P and UI, with contract terms ranging from twenty to thirty years. Resource recovery facilities typically contracted for 20 year terms, while the hydro facilities generally negotiated 30 year contracts.

There are currently four resource recovery facilities and eight hydro facilities located in Connecticut under long term PPAs with CL&P, located in Connecticut—totaling approximately

37 IRP p. 22-23
38 SEA RPS Training Slide deck
39 DEEP RPS Database
40 Currently, Class II RECs trade in the $0.50/MWh range.

52.6 MW. The cost of power from resource recovery projects varies significantly between projects. Resource recovery facilities under long term PPAs will pay between 8.3 cents/kWh and 25.0 cents/kWh in 2012. REC revenues have not been critical to the financial viability of existing Class II resources as long as they are under long term contracts. However, when those contracts expire, these Class II resources may face serious financial challenges.

Several long-term contracts have already expired and others will end in the next few years. The Connecticut Resource Recovery Authority's (CRRA) 67 MW Mid-Connecticut project PPA ended in 2012. Bristol's (13.2 MW) PPA will end in 2014 and the contract with CRRA Preston (13.85 MW) will end in 2017.

Due to the combination of low Class II REC prices and low energy and capacity prices, most of these facilities will likely experience a significant revenue decline at the termination of their PPAs. Some of these resource recovery facilities claim that reduced revenues, unsold RECs, and increased costs have created financial hardship, which could threaten the continued operation of their facilities. These resource recovery facilities may attempt to compensate for revenue shortfalls by increasing disposal prices (tipping fees). Substantial increases in tipping fees, however, may be difficult to pass on to taxpayers given the financial difficulties facing many municipalities.

DEEP has not undertaken an analysis of the waste disposal needs and options in Connecticut as part of this study, but has worked with the Governor's Recycling Task Force and with other stakeholders to develop an approach to managing materials that is economically viable and advances the state's economic and environmental goals. A better understanding of this area is required to determine to what extent, if any, is required to support Connecticut's trash to energy facilities. If it is determined that more REC support is part of the solution, there are two approaches that could be taken to increase revenues to Class II resources. One approach is to raise the Class II requirement to a point where supply and demand are more balanced, thereby increasing the price of Class II RECs. Another approach is to again offer PPAs to resource recovery facilities. Additional recommendations for consideration are part of the Department's waste transformation initiative.

The impact of increasing the Class II is indeterminate since a rise in Class II REC prices could determine their economic viability. Higher REC prices and a larger Class II requirement would raise electric rates for Connecticut ratepayers with a large share of that money going to out-of-state Class II facilities. DEEP believes that PPAs offer a more targeted approach that would

better ensure the continued operation of Connecticut resource recovery facilities at a lower cost to ratepayers than increasing the Class II requirements.

## CLASS III RESOURCES

Connecticut's Class III market is comprised of efficiency measures and energy produced by combined heat and power facilities. The Class III requirement started at 1% in 2007, and increased by 1% each year until reaching 4% in 2010, at which point it remains constant through 2020. Class III RECs have a statutory price floor of 1 cent/kWh and a ceiling of 3.1 cents/kWh that was approved in a PURA decision.[41] DEEP estimates that it cost approximately $12.8 million to meet the Class III RPS requirement in 2012. This cost is expected to remain constant through 2020.[42] In 2010 approximately 52% of the RECs sold to meet the Class III requirement were attributable to efficiency, while 48% were RECs from combined heat and power facilities (Figure 16).

**Figure 16: Connecticut's Class III Resource Mix**

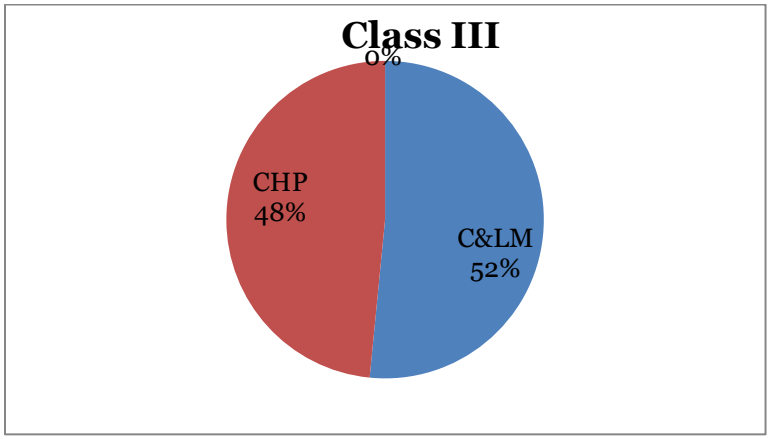



Table 6 below shows the Class III requirements and the qualifying Class III RECs between 2007 and 2010. As seen in Table 6, the current supply of Class III resources is significantly greater than the existing requirements.

**Table 6: Summary of Historical Class III Requirement and Qualifying Resource Output[43]**

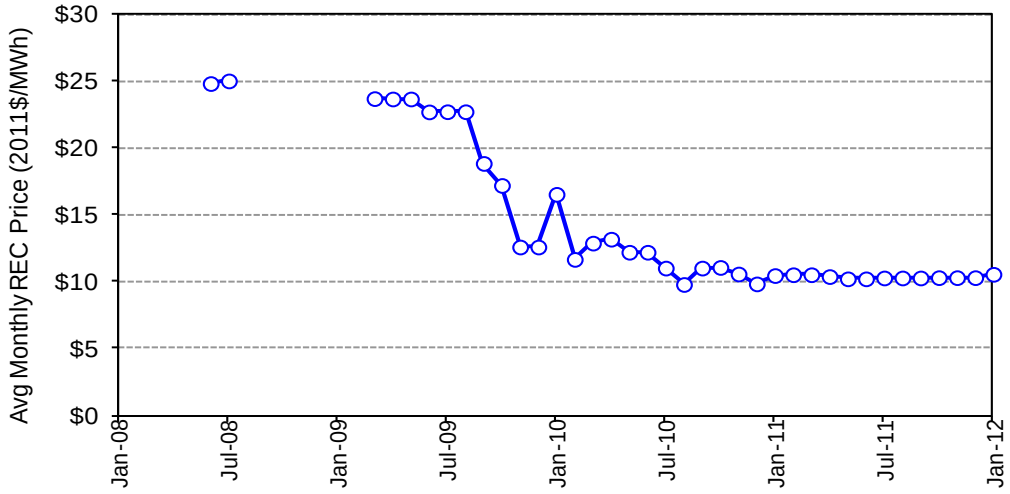
[41] DEEP RPS Data Base
[42] IRP p. 18-19
[43] IRP p. 18-19

| Year | Class III Supply | | | Class III |
|---|---|---|---|---|
| | CHP | C&LM | TOTAL | Demand |
| | *(MWh)* | *(MWh)* | *(MWh)* | *(MWh)* |
| 2007 | 0 | 437,854 | **437,854** | **338,736** |
| 2008 | 124,331 | 783,560 | **907,891** | **656,600** |
| 2009 | 528,219 | 1,002,482 | **1,530,701** | **951,790** |
| 2010 | 645,978 | 1,236,626 | **1,882,604** | **1,280,838** |

**Source:** Class III supply as reported in NEPOOL Generation Information System (GIS). Class III demand calculated based on existing RPS targets increasing from 1% in 2007 to 4% by 2010.

This imbalance has resulted in many Class III RECs selling at the price floor of $10/MWh and many not selling at all. Going forward, DEEP expects the price of Class III RECs to remain at the price floor as the oversupply worsens. Utility conservation programs will generate more Class III RECs each year, keeping REC prices at the floor level and making them increasingly unmarketable.

**Figure 16: Connecticut Class III REC Prices[44]**




*Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the furrent or nearest future compliance year traded in each month.*

Oversupply in the Class III markets has resulted largely from continued growth in utility energy efficiency programs and has impacted third-party conservation efforts. Currently there are no third party conservation providers selling class III RECs. At the floor price there is little hope

44 SEA analysis, "Renewable Energy 101 Training" slide deck

for third-party conservation providers to secure substantial enough REC revenues to make such projects viable without other ratepayer funding in the future.

Sales of Class III RECs provide an estimated $4.5 million in supplemental revenue for utility conservation programs. This additional funding, while helpful, is not essential to the utilities' conservation efforts since they can recover their costs through electric rates.

Low REC prices have also impacted CHP units. Prices at the floor level provide little support for existing CHP units and do not encourage new development. Kimberly Clark, which owns and operates a large CHP unit, has been very outspoken about problems in the Class III REC market. The Class III CHP Organization (C3CO) is a coalition working on behalf of Connecticut hospitals, municipalities, businesses, and CHP developers that have invested in or plan to invest in CHP generation that meets the Class III criteria. C3CO submitted comments in the 2012 IRP and Comprehensive Energy Strategy proceedings discussing the problems of oversupply and low REC prices in the Class III market. C3CO recommends that distributed resources that meet certain environmental standards, including Class III CHP resources, and are located in the state as a means to develop micro grids, be used to offset a portion of the Class I requirement.[45] In the alternative, C3CO suggests creating a new Class IV that would be comprised entirely of conservation and load management projects, thereby removing such resources from the Class III market.[46]

CHP fuel cells are currently eligible as a Class I resource. DEEP does not believe that natural gas fired CHP is a good fit as a Class I renewable energy resource. DEEP believes that the best way to improve the Class III market would be to discontinue eligibility for conservation programs administered by the utility companies. If RECs from utility conservation programs were removed from the Class III market the oversupply situation would reverse and there would be an under-supply of Class III RECs. This would drive the price to the current cap of 3.1 cents per kWh. The higher REC prices would increase revenues for existing CHP projects and provide a greater incentive for new CHP and third party conservation development. DEEP estimates that this would increase costs from approximately $12.8 million annually to $20.0 million annually. Over time the cost would increase as more CHP and conservation is developed. The total maximum cost of Class III would be approximately $40 million, if the entire 3% requirement was met at the ceiling price of 3.1 cents per kWh. DEEP monitors all of the RPS markets. If

[45] Comments of C3CO Comprehensive Energy strategy April 24, 2012.
[46] Comments of C3CO Comprehensive Energy strategy April 24, 2012.

third party conservation and CHP grows to a point where the existing 3% requirement is projected to be filled, DEEP would consider whether the requirement should be increased and present its recommendation to the General Assembly.

DEEP believes that the eligibility for Class III should be modified to only allow conservation and load management and demand response from third party providers that do not receive any ratepayer support. The definition should also clarify that only electric conservation savings are eligible for Class III RECs. Conservation from gas and oil savings should not qualify.

The Class III price cap was originally set by PURA years ago based on the average cost of the utility conservation programs at that time. The level and rationale for the cap should be reexamined periodically and adjusted if necessary.

## CONCLUSIONS AND RECOMMENDATIONS

This study presents a new renewable strategy, in line with Governor Malloy's goal of providing cheaper, cleaner, and more reliable electricity to the citizens and businesses of Connecticut. This study reveals many of the challenges Connecticut faces in achieving its RPS objectives in a cost-effective way. Connecticut's Class I RPS is disproportionately filled by out-of-state legacy biomass and landfill gas projects. Meanwhile, the current Class II and Class III markets are oversupplied resulting in low REC prices that do little to support existing resources or encourage new development. A new balance should be struck that will ensure that clean renewable resources supply an increasing share of Connecticut's electricity at an affordable price. Through carefully timed amendments to the RPS, Connecticut can shift its Class I structure strategically, to promote newer, cleaner renewable projects and get away from reliance on legacy biomass or landfill gas projects. At the same time, costs can be contained to protect the interests of electric ratepayers through the creation of a Class I subtier in which large-scale Canadian hydropower would be eligible (although not receiving RECs). This recommendations outlined below will help to diversify the mix of clean renewable resources (increasing reliability and providing a hedge against rising fossil fuel prices); provide meaningful incentives to project developers to shift support from less-clean, legacy, out-of-state renewables to new and very clean in-state and regional renewables; and reduce criteria air pollutant and greenhouse gas emissions—all at a lower cost to our citizens and businesses.

### Class I Structure, Market Tier, and Contracted Tier

The total Class I requirements should be increased from 20% in 2020 to 25% in 2025. A portion of this total should be filled by the current Class I "market tier" (traditional wind, solar, small-scale hydro, etc.), and the rest should be filled by a new Class I "contracted tier" in which large-scale hydro would be eligible alongside other low-cost Class I resources. Large-scale hydro projects would not have premiums or compete within the current Class I market tier. This contracted tier should begin at 2% in 2014 and be phased up to 4.5% in 2020 and to 7.5% in 2025. This schedule would continue to ensure that Connecticut has the most rigorous RPS among the New England states. To facilitate the procurement of renewable power as called for, DEEP should be given authority to participate in an initial phase of regional Class I renewable procurement (most likely from regional wind resources) in short order to be followed by a second round of renewable power procurement in which large-scale Canadian hydro power would be eligible to compete. The resources selected from both procurements would be used to fill the contracted tier.

### Increase Available Class I Supply by Strategically Conforming Eligibility Criteria to Other States' RPS Definitions

Under Connecticut's current RPS, a small-scale hydro project must be built after 2003, be run of river, and be less than 5 MW to qualify as a Class I resource in Connecticut. The definition for hydro for Class I eligibility should be increased from 5 MW to 30 MW. DEEP also recommends that "run of river" requirement be removed and replaced by Low Impact Hydropower Institute certification. The other existing conditions should remain. Connecticut allows "methane from landfill gas" as a Class I resource, as does each of the other New England states. The Class I resource definition should be modified to allow all biologically derived methane/biogas from sources such as yard and plant matter, food waste, animal waste and sewage sludge is eligible as a Class I source. Anaerobic digesters should also be allowed to qualify as a Class I resource in Connecticut

### Gradually Transition Away from Class I Subsidies for Legacy Biomass and Landfill Gas

Connecticut currently allows legacy, less-clean biomass and landfill gas facilities to qualify under Class I. A careful, deliberate transition away from a reliance on these older, dirtier facilities can be accomplished through gradual introduction of more stringent emission controls, which will either encourage these facilities to deliver cleaner energy, or promote the development of new, cleaner resources. This transition should be carefully timed so as not to become effective until either these other Class I resources can be developed, or for large-scale hydro to meet the region's needs.

## Modify Class III Eligibility Criteria

Since the programs provided through the State's Conservation and Load Management Plan are already supported through ratepayers, this draft study recommends that any efficiency programs supported by ratepayer funding not be eligible to qualify for additional ratepayer support through the Class III market. Eliminating these resources would open up the market to more combined heat and power (CHP) projects.

# APPENDIX A

### Incorporating Large scale Hydro into CT's Class I RPS Design

| Issue | Options | Pros | Cons |
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| Structure of Class I Contracted Tier | Expand Class I eligibility to include large hydro | RPS compliance costs may be reduced significantly | Inclusion of large hydro would effectively overwhelm CT market; resulting displacement of eligible generation would create ripple effect into other NE Class I RPS markets; this option would fail to limit large hydro's role to the amount procured under contemplated contracts; actual and perceived supply-demand balance would shift into an expectation of extreme surplus; scale of impact would render many advanced renewables development projects in pipeline unfinanceable; this option would threaten to overfill RPS targets so that EDCs might be unable to resell RECs (that they were required to purchase); RPS best practices are violated; generation already developed would be pushed out of market, causing shutdown of facilities and damaging financial stability of generators that invested substantially based on current CT RPS; expectations of political uncertainty would be exacerbated; this option would create substantial market power problems |
| Structure of Class I Contracted Tier | Create a distinct Class I sub-tier for which large hydro would be eligible | Policy objectives can be accomplished without dramatically oversupplying CT's Class I market or creating a market power problem; RPS costs would be reduced to extent that some portion of the Contracted Class I tier replaced a portion of the Market Class I tier | Large hydro generation would be limited to size of sub-tier (any cost reduction to the Market Class I tier would be less than if size is unlimited) |

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| Structure of Class I Contracted Tier | Create a separate RPS tier, or a non-RPS tier outside of current RPS policy | No impact on Class I market; displacement of fossil-fueled generation | No savings (it will not displace Class I or impact REC prices in Class I market) |
| Geographic eligibility | Retain current geographic footprint | This option ensures a nexus to retail sales, no double counting, displacement of fossil-fueled generation within ISO-NE; consistency with current treatment and underlying rationale; approach avoids reopening one of most controversial aspects of RPS program and NEPOOL GIS design; adequate supply is likely to be available without undertaking a change | This option may provide less competitive options and competitive price pressure than one that expands geographic footprint |
| Geographic eligibility | Expand geographic footprint to include Newfoundland and Labrador | This option provides CT with greater range of potential sources (thereby resulting in increased competitive pressure and the potential for a better competitively-derived price) | It would be highly controversial to do so in the RPS rules and the GIS; such a change would likely create slippery slope, with unintended consequences altering the entire region's RPS landscape (unless implemented in a narrowly limited manner) |
| Vintage eligibility threshold | Limit eligibility to *new* large hydro only | Consistency with current CT hydro eligibility; this option is necessary to satisfy additionality; ample supply of planned new hydro to meet any reasonable target for a CT Contracted Class I tier | Less supply is available than if there is no vintage eligibility threshold |
| Vintage eligibility threshold | No vintage eligibility threshold | Broader base of supply from which to meet target | This option is likely to be highly controversial and fails to satisfy additionality objective; it conflicts with rationale applied to limit hydro to new under current RPS statute; this option is unnecessary as existing large hydro is already competitive with other energy sources |
| Threshold date for commercial operation | After 10/1/2011 | Date is linked to passage of PA 11-80 (when legislature instructed DEEP to perform this analysis) | n/a |
| Threshold date for commercial operation | After 7/1/2003 | Consistency with existing CT Class I RPS threshold for hydro eligibility | n/a |

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| Threshold date for commercial operation | After 12/31/1997 | Consistency with Massachusetts RPS and Rhode Island RPS | n/a |
| Threshold date for commercial operation | After 8/1/1998 | Consistency with LIHI standard/ definition for new hydropower facilities | Little rationale for applying LIHI standard if other LIHI limitations are not applied (e.g., allowing existing dams) |
| Capacity threshold | No cap | This option maximizes available supply and competition | This option does not screen out the largest projects (which, arguably, could have the highest social/environmental impact) |
| Capacity threshold | MW cap at some larger amount | This option may screen out the highest impact projects | This option limits available supply and competition |
| Flow or impoundment limitation | Generation limited to facilities that do not create new impoundments | Lower environmental impact than hydro that does not require new impoundments | This option excludes the very resources driving the policy's consideration (which defeats purpose of establishing the Contracted Class I tier) |
| Flow or impoundment limitation | No limitation | This option maximizes available supply and price competition | Allowance of generation with greater potential environmental impacts than small run-of-river hydro |
| Greenhouse gas emissions | No standard | | |
| Greenhouse gas emissions | Disclosure standard of greenhouse gas impacts | | |
| Greenhouse gas emissions | Greenhouse gas impact threshold standard | | |
| Approach for securing a firm offer | Competitive procurement | This approach is appropriate for a public process since it provides a level of transparency and confidence that the best price is secured through a competitive process; with multiple potential suppliers, competitive dynamics may lead to both more favorable pricing and a more solid justification than option of bilateral negotiations; other technologies/ entities might be able to compete and, at least, provide competitive pressure | Increased complexity; longer lead time for implementation |
| Approach for securing a firm offer | Bilateral negotiations | Simplicity; faster resolution and implementation than other options; more direct means to engineer transaction to facilitate getting new transmission built (more certain to drive that specific investment) | Lack of transparency; inability to represent that the best price was secured |

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| Approach for securing a firm offer | Hybrid approach seeking expressions of interest and indicative proposals | This option provides greater comfort with a competitively-derived option and price than the bilateral negotiations option; it potentially allows more rapid implementation and customization | Less transparency than the competitive procurement option; less certainty of best price than the competitive procurement option (indicative proposals are rarely firm) |
| Price structure | Comparison against a forecast | CT could solicit proposals that are either fixed price or indexed; bids could be compared against a value-adjusted BAU forecast of electricity prices for comparable products; a bid price at this cost benchmark would represent no premium, and a price below that benchmark would represent savings, relative to *expected* electricity costs | Applying this option requires development of a forecast and a method for value adjustment; this option potentially deprives CT of the benefits of competition |
| Price structure | Comparison against future energy prices | CT could seek proposals that are indexed at a fixed discount; such an index would ensure that any purchase would always create savings | In practice, this option is not expected to be viable without allowing the bidder to propose a price floor; without a floor, there is no value to the bidder (who needs to have a minimum level of revenue certainty to finance generation or transmission facilities); a supplier that is always able to sell into the ISO-NE spot market without a discount has no incentive to offer a discount without a price floor |
| Delivery point | Priced at NEPOOL PTF | The bid price may be less than the alternative | This option adds complexity of making comparisons dependent on a forecast of future basis differentials between ISO zones |
| Delivery point | Priced at CT Zone | Easier evaluation | There is a risk that the price would be higher |
| PPA purchase duration | Contracted Class I tier PPAs are fulfilled via bilateral negotiations with new, large scale Canadian Hydro *(15 year contract)* | Consistency with term of other in-state programs (e.g., LREC/ZREC) | This option may not be least-cost |

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| PPA purchase duration | Contracted Class I tier PPAs are fulfilled via bilateral negotiations with new, large scale Canadian Hydro *(25+ year contract)* | Longer contract might drive costs down | Sellers may be less willing to discount price for a longer duration PPA than the owner of a generation facility requiring the PPA to secure financing (if Canadian utilities have a bullish long-term outlook on value of power supply, and do not require the PPA in order to commit financing) |
| PPA purchase duration | Contracted Class I tier PPAs are fulfilled via a competitive solicitation open to any Class I technology *(15 year contract)* | Consistency with term of other in-state programs (e.g., LREC/ZREC) | This option may not be able to achieve contract at no premium to expected market price or may not allow other renewables to be cost-competitive with large hydro |
| PPA purchase duration | Contracted Class I tier PPAs are fulfilled via a competitive solicitation open to any Class I technology *(25+ year contract, not exceeding project technical life)* | Longer PPA duration will drive costs down for projects not yet financed; the playing field is leveled between IPP generation and provincially-owned generation; this option increases likelihood of procurement at no premium to market; more defensible option from a cost perspective | Possibly, treatment of a longer term as a capital lease by EDCs, if they are the contracting counterparty |
| PPA purchase duration | Contracted Class I tier PPAs are fulfilled via a competitive solicitation open to any Class I technology *(solicitation of a variety of contract durations)* | This option allows comparison across multiple terms; it is hard to know what PPA is least-cost (as different bidders may place different value on different commitment duration); seeking pricing for a variety of terms would allow CT to identify the most attractive term and supplier | Evaluation is likely to be more complex, depending on the nature of offers |