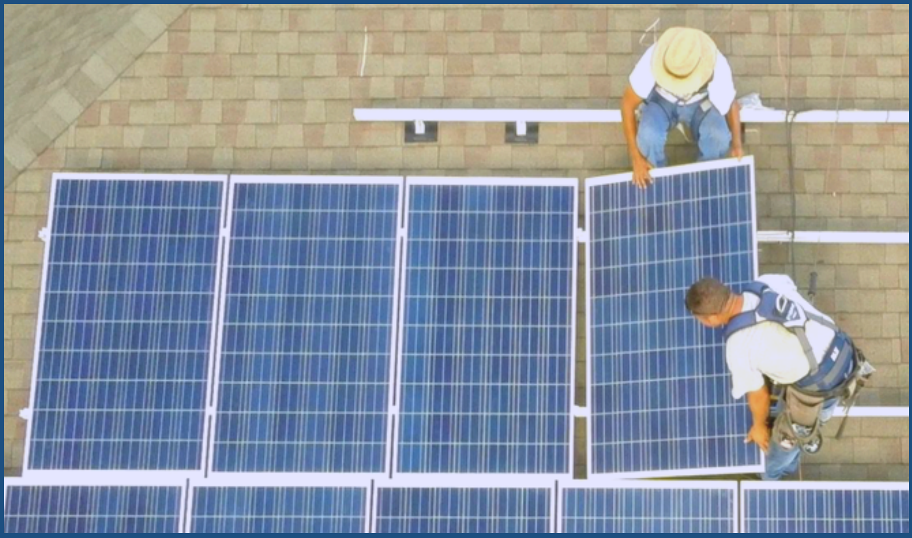
Prepared in accordance with Section 16a-3a of the Connecticut General Statutes



Integrated Resources Plan

Pathways to achieve a 100% zero carbon electric sector by 2040

DECEMBER 2020

Connecticut Department of Energy and Environmental Protection

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Glossary

Term	Definition
AC	Alternating current
ACP	Alternative Compliance Payment
ASHP	Air source heat pump
BOEM	Bureau of Ocean Energy Management
BTM	Behind-the-meter
BTU	British Thermal Unit
C&I	Commercial and industrial
C&LM	Conservation and Load Management
CASPR	Competitive Auctions with Sponsored Policy Resources
CCIS	Capacity Commitment Interconnection Service
CCP	Capacity Commitment Period
CES	Comprehensive Energy Strategy
CMMS	Connecticut Comprehensive Materials Management Strategy
CSO	Capacity supply obligation
DC	Direct current
DEEP	Department of Energy and Environmental Protection
DER	Distributed energy resource
DG	Distributed generation
DOER	Massachusetts Department of Energy Resources
DR	Demand response
E&AS	Energy and ancillary services
EDC	Electric distribution company
EFMP	Environmental and Fisheries Mitigation Plan
EO3	Executive Order 3
ESI	Energy Security Improvements
ETU	Elective transmission upgrade
EV	Electric vehicle
Eversource	Eversource Energy (formerly Connecticut Light & Power)
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPL	Federal Poverty Level
GC3	Governor's Council on Climate Change
GHG	Greenhouse gas
GW	Gigawatt
GWSA	Global Warming Solutions Act

Term	Definition
HVDC	High-voltage direct current
ICR	Installed capacity requirement
IRP	Integrated Resources Plan
ISO(-NE)	Independent System Operator (of New England)
LAI	Levitan Associates, Inc.
LBW	Land-based wind
LMG	Landfill methane gas
LMP	Locational marginal price
LNG	Liquefied natural gas
LREC/ZREC	Low-carbon renewable energy credit/zero-carbon renewable energy credit
LSE	Load-serving entity
METU	Market Efficiency Transmission Upgrade
MIRA	Materials Innovation and Recycling Authority
MOPR	Minimum Offer Price Rule
MR1	Market Rule 1
MSW	Municipal solid waste
MWa	Average Megawatt
MWh	Megawatt hour
(NB)FMCC	(Non-bypassable) federally mandated congestion charge
NEPA	National Environmental Policy Act
NEPOOL (GIS)	New England Power Pool (Generation Information System)
NESCOE	New England State Committee on Electricity
NO_x	Nitrogen oxides
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
OATT	Open Access Transmission Tariff
OFSA	Operation Fuel Security Analysis
OSW	Offshore wind
PA	Public Act
PFP	Pay-for-Performance
PPA	Power Purchase Agreement
PPTU	Public policy transmission upgrade
PTF	Pool transmission facility
PURA	Public Utility Regulatory Authority
PV	Photovoltaic
REC	Renewable energy credit
RFP	Request for proposal
RMR	Reliability must-run
RNS	Regional network service

Term	Definition
ROE	Return on equity
RSIP	Residential Solar Incentive Program
(R)TO	(Regional) transmission operator
RTR	Renewable technology resource
RTU	Reliability Transmission Upgrade
SA	Substitution auction
SCC Price	Social Cost of Carbon Price
SEA	Sustainable Energy Advantage
SO_x (SO_2)	Sulphur oxides (sulphur dioxide)
(T-)RPS	(Thermal) renewable portfolio standard
UI	United Illuminating
Value of DER Study	Value of Distributed Energy Resources in Connecticut Study
VER	Variable energy resource
VNM	Virtual net metering
WTE	Waste-to-energy
WTG	Wind turbine generator

Executive Summary

With overwhelming scientific evidence of the threat of global climate change, swift action is critical, including leadership at the state level in decarbonizing the state's electric supply. In Executive Order 3, issued in September 2019, Governor Lamont directed the Department of Energy and Environmental Protection (DEEP, or "the Department") to identify pathways within this Integrated Resources Plan (IRP) to achieve a 100 percent zero carbon electric supply by 2040 ("100% Zero Carbon Target"). The significant investments Connecticut has made over the years in robust clean energy and energy efficiency programs have already put the state on a strong path to achieving the 100% Zero Carbon Target. For example, through direct investment in the form of long-term contracts, Connecticut ratepayers are currently supporting grid-scale, zero-emission renewables and zero-carbon nuclear resources equivalent to nearly 65 percent of the electricity consumed by customers of the state's two electric distribution companies: Avangrid, Inc. and Eversource Energy (the "EDCs"). By 2025, that percentage is expected to increase to 91 percent, as new offshore wind and grid-scale solar projects that have been contracted but not yet constructed are scheduled to come online.

This IRP assesses Connecticut's current and future electricity supply, in accordance with Public Act 16a-3a, with respect to six key objectives:

1. Decarbonizing the Electricity Sector

The modeling in this IRP tested four different scenarios under two load levels to evaluate potential costs, fossil fuel retirements, and new resources needed to meet the 100% Zero Carbon Target while maintaining system reliability. Each of these scenarios tests different blends and quantities of zero carbon electric generating resources like on- and offshore wind, grid-scale solar, and battery storage, but all enable Connecticut to meet its 100% Zero Carbon Target by 2040. In addition to assessing pathways to achieve the 100% Zero Carbon Target pursuant to EO3, the IRP is required to plan for the state's energy needs consistent with the State's statutory greenhouse gas (GHG) emissions reduction goals to reduce economy wide emissions 45 percent by 2030 and 80 percent by 2050.[1] **This IRP concludes that there are multiple pathways available to achieve the 100% Zero Carbon Target, and doing so will further the state's ability to meet its GHG emissions reduction goals. Thus, Connecticut should codify the requirement to achieve a 100 percent zero carbon electric supply by 2040.**

2. Securing the Benefits of Competition & Minimizing Ratepayer Risk

One of the key aims of the deregulation of electricity supply in Connecticut was to achieve lower-cost electricity by relying on competitive markets to source the State's power supply, thereby insulating ratepayers from the risks of uneconomic investments and stranded costs. This IRP evaluates the extent to which Connecticut ratepayers are obtaining the benefits of deregulation under the current market paradigm.

Current energy markets are not producing investment in clean energy resources, causing Connecticut to have to procure, through state jurisdictional markets and mechanisms, the resources needed to meet the State's Renewable Portfolio Standard (RPS) and other GHG emission reduction goals. That fact, coupled with the wholesale market's overreliance on natural gas generation, has placed Connecticut

[1] Conn. Gen. Stat. § 22a-200a.

ratepayers at risk of paying unreasonable and duplicative costs for energy supply, and take on additional costs to preserve fuel security in the region. The ISO-New England (ISO-NE) governance structure lacks accountability and transparency. **Collaborating with other New England states, Connecticut must achieve reform of the ISO-NE regional wholesale markets to ensure they are meeting the needs of the states and their ratepayers,** including Connecticut's need to meet emissions reduction goals and provide reliability at the lowest cost to ratepayers.

The IRP analysis reveals several time-urgent, threshold issues that need to be resolved. These include **reforming the wholesale electricity markets, improving transmission planning and scaling investment in storage, efficiency, and demand response to optimize interconnection points and minimize renewable curtailment, and addressing siting concerns for renewable resources**. A near-term (2021-2022) focus on these efforts will prepare the state to efficiently deploy new zero carbon resources. With significant quantities of clean energy under contract, based on what is "known and knowable" and not taking into account a variety of potential contingencies further described below, the IRP modeling projects that new grid-scale resources to meet the 100% Zero Carbon Target may need to be procured beginning in 2023.

Distributed generation (DG) resources such as solar and fuel cells have a significant role to play in providing resilience, portfolio diversification, and economic benefits, and they can be simpler to site than grid scale resources. The tariffs being developed by the Public Utilities Regulatory Authority (PURA) to support these resources, in Docket No. 20-07-01 and pursuant to Section 16-244z(b), will create a transparent, fixed incentive mechanism for both energy and RECs associated with DG. In developing that incentive, it is important to **maintain historic deployment levels of DG achieved through the Residential Solar Incentive Program (RSIP) and low-carbon renewable energy credit (LREC) and zero-carbon renewable energy credit (ZREC) programs to continue the pace of diversifying the State's zero carbon resources and sustain the existing in-state economic infrastructure supporting these programs**. Recommended deployment levels could change in future years if additional benefits to distributed generation are unlocked through grid modernization or if the current price gap between grid scale and DG resources decreases.

3. Ensuring Energy Affordability and Equity for all Ratepayers

Due in significant part to the ISO-NE energy market and governance concerns highlighted in Objective 2, Connecticut has some of the highest electric rates in the United States, and an energy affordability gap that has serious impacts on low to moderate income utility customers and the communities they live in. **The state's electricity supply should be affordable for all customers and maximize residential and business customer value to ensure that Connecticut continues to be economically competitive.** Regional market reform, governance changes, and a proactive approach to transmission planning must be prioritized to address energy affordability.

In addition, **energy equity requires expanding access and removing barriers for underserved and overburdened customers to participate in Connecticut's energy policy programs**, consistent with the direction from Governor Lamont in EO3 that the Governor's Council on Climate Change (GC3) analyze climate mitigation and adaptation progress through that lens. This IRP recommends that incentive levels for the residential rooftop solar successor tariff be structured to ensure at least 40 percent of the installations are deployed at low income households statewide, and low to moderate income households in environmental justice communities. To further address energy equity and affordability, this IRP recommends increasing the low-income and low to moderate income subscribership requirements under the SCEF program structure, working towards a 100 percent low- to moderate-income subscribership goal. Moreover, DEEP's Equitable Energy Efficiency proceeding will identify barriers to equitable participation in energy efficiency programs and pathways to address those barriers, and develop metrics for defining equity and measuring program outcomes from an equity perspective.

4. Optimal Siting of Generation Resources

Since deregulation, Connecticut's accessible transmission infrastructure and other energy infrastructure have made it a target location for the development of merchant fossil fuel-powered generation facilities. Fossil fuel generating resources are primarily constructed in low income or historically marginalized communities, creating inequitable air quality and environmental justice issues. Adoption of the 100% Zero Carbon Target for the state's electricity supply will ensure that the state can clearly plan for and achieve a decarbonization goal that will, in concert with similarly robust targets being adopted by other states in the New England region, minimize operation of fossil fuel generation in the region. **Pursuing reforms of the wholesale electricity markets will put an end to ISO-NE market rules that over procure capacity, prevent state clean energy investments from clearing in the capacity market, and imbed preferences for natural gas and other fossil resources in the capacity market.** Fully reforming the market will ensure that zero carbon resources are selected to meet public policy and reliability needs.

Siting of renewable and zero carbon generation also has its challenges, including potential impacts to natural resources, environmental quality, and agricultural resources. **Connecticut must fully align its energy and environmental policies, by incorporating eligibility criteria in procurements that reflect a consistent and appropriate balance of price, environmental quality and natural resource values, and providing transparent, predictable and efficient permitting and siting processes for renewable energy resources.** This IRP calls for a stakeholder engagement process, led by DEEP, to improve and refine solar siting and permitting practices with respect to grid-scale procurements, and to develop siting practices tailored to DG, virtual net metering, and LREC/ZREC solar projects. The IRP also recommends leveraging regional approaches to improve our understanding of the best available science, tools, and practices for environmental and commercial fisheries mitigation for OSW siting through entities such as the Northeast Regional Ocean Council, the Responsible Offshore Development Alliance/Responsible Offshore Science Alliance, and, once established, the Regional Wildlife Science Entity for Offshore Wind. As required by Public Act 19-71, DEEP will also utilize input from the Commission on Environmental Standards and will incorporate resulting best siting practices for OSW as requirements in future solicitations.

5. Transmission Upgrades & Integration of Variable and Distributed Energy Resources

Today's wholesale electric power grid, and the electric markets it supports, have been designed around the development of traditional, dispatchable (i.e. controllable) resources such as natural gas and oil generators. While the transmission system has capacity to support some variable energy resources (VERs) like wind and solar in the near term, modeling demonstrates that curtailment of intermittent resources will happen in each of the modeled pathways to a 100% Zero Carbon Target. **Upgrading the transmission system can significantly reduce curtailment of VERs over the next two decades.** With reduced curtailment, less clean energy will be wasted, thus reducing any oversupply needed to meet reliability and emissions requirements. The modeling shows that eliminating or reducing transmission constraints can also reduce the overall ratepayer costs of achieving the 100% Zero Carbon Target.

Under the current ISO-NE tariff, proactive planning is a challenge, as the approach has been primarily reactive. In order to address state policies, a scenario-based proactive planning process is needed. **As the region pursues further deployment of both grid-scale and BTM resources, the New England states must work to upgrade the existing transmission system to unlock constraints and maximize the value of zero carbon generation. In addition, Connecticut must invest in energy efficiency, active demand response and storage resources to reduce and manage load to balance VERs.**

6. Balancing Decarbonization and Other Public Policy Goals

Connecticut's energy policies currently support technologies that are not zero emissions but provide solutions for other important public policy goals. **In evaluating pathways to reach a 100% Zero Carbon Target for electric supply by 2040, the IRP recognizes the distinct and related policy goals of the RPS and the Global Warming Solutions Act.** Waste-to-energy (WTE) plants, for example, emit GHGs and other air pollutants, but provide vital services to the state in avoiding landfilling and maintaining self-sufficient waste disposal. **The IRP highlights opportunities to align the state's decarbonization efforts with the broad public policy goals of the RPS and other state policy goals.** This includes phasing down reliance on biomass, and seeking to diversify the state's waste management infrastructure by scaling up deployment of anaerobic digestion.

There is significant work to be done to achieve the Objectives set forth above. This IRP establishes several priority actions over the next two years, including:

- Codify the 100% Zero Carbon Target for electric supply.
- Pursue regional wholesale market reform and improvements to the transparency and governance of ISO-NE.
- Work with other states to upgrade the transmission system to unlock the potential for additional renewable resources, particularly offshore wind.
- Monitor contingencies to determine whether new procurements of grid-scale renewables are needed prior to 2023.
- Explore retaining RECs purchased through procurements and public policy programs as a more cost-effective way of meeting the 100% Zero Carbon Target and align Connecticut's greenhouse gas accounting practices with the Strategies in this IRP.
- Engage in stakeholder processes to develop best siting practices for renewables for incorporation in future procurements, and make permitting requirements more transparent, predictable and efficient.
- Invest in equitable energy efficiency and active demand response through additional DEEP procurement authority.
- Support historic deployment levels for DG resources, with a focus on low-income customers in the residential and shared clean energy successor tariffs.
- Engage in coordinated planning for workforce and economic development.

This IRP outlines several contingencies in Strategy 5 that could affect a procurement schedule designed to meet the 100% Zero Carbon Target. DEEP therefore concludes it is prudent to monitor contingencies and provide an update to the procurement schedule set forth in Strategy 5 at least every 12 months.

This will help determine if a procurement will need to occur sooner than 2023 due to changed conditions. DEEP will commit to providing the first update no later than January 1, 2022.

This IRP also considers the creation of a "portfolio standard for thermal energy," including "biodiesel that is blended into home heating oil," as required by Public Act 19-35. Given the current lack of ASTM standards for biodiesel blends in home heating oil above 20 percent, lack of boiler manufacturer certifications for equipment under Underwriter Laboratories protocols just now being published, and uncertainty about the cost of boiler equipment alterations required, this IRP does not recommend creating a thermal renewable portfolio standard (T-RPS) to support biodiesel. Significant questions also remain about whether more extensive use of biodiesel would reduce or exacerbate NOx emissions, which is of particular concern in environmental justice communities already disproportionately burdened by poor air quality. While this IRP does not recommend the creation of a portfolio standard for thermal energy at this time, DEEP will track these open issues and will consider a renewable thermal portfolio standard in the upcoming Comprehensive Energy Strategy, among other options for encouraging investment in renewable thermal technologies.

Introduction

Section 16a-3a of the Connecticut General Statutes requires DEEP to prepare an Integrated Resources Plan (IRP) for Connecticut's electricity supply. The IRP is intended to assess the resources available to meet the State's needs for energy and capacity, and develop a plan for procuring energy resources "in a manner that minimizes the cost of all energy resources to customers over time and maximizes consumer benefits consistent with the State's environmental goals and standards, including, but not limited to, the State's greenhouse gas reduction goals."[2]

Before Connecticut deregulated its electricity sector, integrated resources plans were prepared by the predecessor entities of the state's two current electric distribution companies, Eversource Energy and Avangrid, Inc. (EDCs)—who had exclusive ownership of the electric generating facilities at the time— to ensure that they had an acceptable plan to procure the power supply needed to meet expected customer demand over a long-term planning horizon. Public Act 98-28 directed the EDCs to divest their generation assets and caused the State to rely primarily on wholesale markets under the jurisdiction of the Federal Energy Regulatory Commission (FERC or "The Commission") for Connecticut's energy supply. By the same Public Act, however, the State established a preference for an increasing portion of the State's supply to be met by clean and renewable energy sources and funded the State's utility-administered energy efficiency programs.

Since that time, Connecticut has continued with the practice of integrated resources planning—conducted by State policymakers, in consultation with the EDCs—to ensure that the State's preferences for clean energy, efficiency, and other policy-supported resources are being met, and that the regional electricity system is adequately meeting a variety of objectives. The Connecticut General Statutes spell out many specific resource objectives that must be considered in the IRP's resource assessment. Consistent with those requirements, the objectives examined in Part I of this Integrated Resources Plan are as follows:

1. **Decarbonizing the Electricity Sector.** Pursuant to Governor Lamont's Executive Order No. 3, this IRP assesses pathways to achieve a 100 percent zero carbon electric supply by 2040 ("100% Zero Carbon Target"). In addition, the IRP is required to plan for the state's energy needs consistent with the State's greenhouse gas emissions reduction goals to reduce economy wide emissions 45 percent by 2030 and 80 percent by 2050.[3]
2. **Securing the Benefits of Competition & Minimizing Ratepayer Risk.** One of the key aims of deregulation was to achieve lower-cost electricity by relying on competitive markets to source the state's power supply, thereby insulating ratepayers from the risks of uneconomic investments and stranded costs. This IRP evaluates the extent to which Connecticut ratepayers are obtaining the benefits of deregulation under the current market paradigm, and the measures that have been taken to advance state policies outside of the markets and will need to be taken in the future absent market reform.
3. **Ensuring Energy Affordability and Equity for all Ratepayers.** The state's electricity supply should be affordable for all customers and maximize residential and business customer value to ensure Connecticut has continued economic competitiveness. Moreover, energy equity requires

[2] Conn. Gen. Stat. § 16a-3a(a).
[3] Conn. Gen. Stat. § 22a-200a.

expanding access and removing barriers to participation in Connecticut's energy policy programs by underserved and overburdened communities.

4. **Optimal Siting of Generation Resources.** Is the use of generation sites in Connecticut optimal? How are new and legacy fossil-fired generation facilities in the state impacting local air quality, and environmental justice communities? In addition, as the state invests in new renewable and other zero emission resources to meet our decarbonization goals, this development must be harmonized with environmental quality, natural resource, and other land use protections.
5. **Transmission Upgrades & Integration of Variable and Distributed Energy Resources**. As the New England region pursues deeper decarbonization, through the deployment of both grid-scale and behind-the-meter resources, it becomes increasingly important to upgrade the existing transmission system to prevent curtailments and thereby ensure ratepayers receive the full amount of energy these zero carbon resources are able to produce, as well as accelerating the deployment of energy efficiency to reduce load, and storage and active demand response to balance intermittent resources.
6. **Balancing Decarbonization and Other Public Policy Goals.** Connecticut's Renewable Portfolio Standard has been a critical policy tool for advancing investment in clean energy as well as supporting other important public policies, such as promoting economic development and maintaining in-state waste disposal infrastructure. Over time, the State's progress towards achieving sustainability goals and economy-wide GHG emissions reductions will provide opportunities to harmonize all the public policy goals underlying the RPS and other electric sector programs.

After assessing each of these objectives, Part II the IRP evaluates and proposes a set of resource and procurement strategies that meet the various objectives. Part III of this IRP considers the creation of a "portfolio standard for thermal energy," including "biodiesel that is blended into home heating oil," as required by Public Act 19-35.[4]

It is important to note that integrated resources planning involves developing a variety of assumptions based upon is the best available information that is known and knowable at the time the modeling for the IRP is conducted. Given the relatively rapid rate of technological advancement and market transformation in the electric sector, near-term modeling results are inherently more reliable than longer-term projections. Moreover, this IRP is not a full cost-benefit analysis of policies supporting different zero carbon resources; rather, it analyzes the price and emissions impacts of pathways to meet the 100% Zero Carbon Target based on current policy and market structures. Changes to market structure, as called for in Objective 2, upgrades to the transmission system, as called for in Objective 5, as well as a variety of other contingencies could have meaningful impacts on the projections made in this IRP. The Department's biennial IRP cycle is designed to allow Connecticut's policy approaches to be adapted and refined over the medium and long term in response to changing conditions.

[4] Conn. Gen. Stat. § 16a-3a.

Objective 1: Decarbonizing the Electricity Sector

Events on the regional, national, and international stage highlight the urgency of decarbonization in Connecticut. The early impacts of global climate destabilization make it clear that our communities and infrastructure are profoundly vulnerable. Month after month, headlines about climate change grow increasingly ominous: a long series of global temperature extremes; hurricanes wreaking ever more destruction; rapid deterioration of the polar ice caps, portending rapid sea level rise; unprecedented wildfires on several continents; troubling changes in major ocean currents. In Connecticut, climate change impacts are particularly a threat in shoreline and other low-lying areas, as well as for forested areas weakened by drought and invasive pests, increasing the likelihood of power outages resulting from storm damage to electric infrastructure.

The extent of these impacts depends on the decisions we make now on our global emissions. The 2018 National Climate Assessment authored by the US Global Change Research Program found that, under the International Panel on Climate Change (IPCC) business-as-usual scenario, annual losses to labor productivity and coastal property could reach hundreds of billions of dollars by 2100.[5] However, these same economic damages can be significantly reduced if instead our global emissions peak by 2040 and continue to decrease thereafter with an 85 percent lower emissions level by 2100. Under this scenario, for example, we can reduce the number of deaths and health risks from climate change by 50 percent.

In Connecticut, climate change has already impacted our state. By 2050, Connecticut will experience up to 20 inches of sea level rise, an increase in coastal flooding from once every few years to multiple times per year, an increase in the average temperature by 5°F, and increased frequency of drought, hot weather, intense storms, and extreme precipitation. These expected changes will impact the reliability and cost of electricity supply. Beyond 2050, the extent of these impacts in the state highly depends on our choices on how to address emissions. The impacts we can expect to see between now and 2050 are serious, but with careful planning, using the best available climate science, we can adapt to them. Impacts in the latter half of the century however become increasingly severe with the potential to cause widespread disruption in the state and making adaptation measures extremely costly. For example, sea level could rise by as much as 80 inches by 2100 without reductions in GHG emissions. With emissions reductions, we increase the likelihood that our temperature could stabilize, but with no reductions, temperatures will continue to rise. Investment in deep, systemic reductions in GHG emissions to prevent climate destabilization from continuing to escalate is crucial to avoid more catastrophic costs in human lives, health risks, and economic damage, and is more cost effective than an adaptation-only strategy.

In 2008, Connecticut enacted the Global Warming Solutions Act (GWSA), Connecticut General Statutes Section 22a-200a, requiring significant long-term reduction of GHG) emissions across all sectors of the economy: an 80 percent reduction in GHG emissions from 2001 levels by 2050. The GWSA was amended in 2018 to establish a mid-term goal of 45 percent reduction in GHG emissions from 2001 levels by 2030. These emission reductions must be achieved across transportation, buildings, and the electricity sector, which are the major contributors to GHG emissions in the state.

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[5] *See* Fourth National Climate Change Assessment, U.S. Global Change Research Program, 2018, p. 1358, Figure 29.2 (interpreting the economic impacts of the International Panel on Climate Change, Representative Concentration Pathway (RCP) 8.5).

In September 2019, Governor Lamont signed Executive Order 3, which directed DEEP to analyze in this IRP pathways to achieve a 100 percent zero carbon electric supply by the year 2040. Connecticut's policies and programs to date have advanced the state well on its way to meeting this 100% zero carbon Target. Over the last two decades, Connecticut has achieved significant decarbonization of the electricity supply through a variety of programs and investments:

- **Retirement and reduced operation of coal- and oil-fired power plants.** In 2000, oil- and coal-fired generation accounted for approximately 22 percent and 18 percent, respectively, of the total electricity consumed (MWh) in New England.[6] As of 2019, oil and coal collectively accounted for less than one percent of the region's electric generation (MWh).[7] Environmental regulations have changed fossil generator economics, and the increased availability of lower-priced natural gas fuel has accelerated the shift of the region's generation fleet away from older and dirtier coal and oil plants. Through Connecticut's participation in the Regional Greenhouse Gas Initiative (RGGI), the State has instituted a regional cap on carbon emissions from the electric power sector, incenting fossil generators in the eleven northeast states participating in RGGI to minimize their carbon footprint. The Regional Greenhouse Gas Initiative is the nation's first mandatory multi-state market-based program to cap and reduce CO_2 emissions from the power sector. Between 2005-2018, RGGI-participating states experienced a reduction of over 90 million short tons of annual power sector carbon pollution, a 50 percent reduction.[8]
- **Increased energy efficiency.** Over the last twenty years, Connecticut's Conservation & Load Management (C&LM) programs have led to the increased installation of energy efficiency measures in residential homes and in commercial and industrial facilities. These successfully installed measures have cumulatively produced 70,900 MWhs in savings, reducing the need for 1,000 MW worth of new power plant construction, while reducing the energy bills of participating customers.[9] Connecticut's energy efficiency programs promote the permanent reduction of energy usage by influencing market transformation. The energy efficient products, green building codes, and efficient appliance and lighting standards facilitated by Connecticut's programs have helped transform the market, resulting in more efficient buildings and products even without program participation. Changes in the residential lighting market, accelerated by the State's energy efficiency program, saw LED saturation (defined as the percentage of all sockets fitted with LEDs) more than double between 2015 and 2018 – equivalent to a tenfold increase from 2012.[10] As of 2019, 56 percent of commercial and industrial, and 29 percent of residential annual energy savings reported by the C&LM Plan result from lighting upgrades.[11]

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[6] ISO New England, Resource Mix, *available at* https://www.iso-ne.com/about/key-stats/resource-mix/.
[7] *Id.*
[8] Regional Greenhouse Gas Initiative, Inc., The Investment of RGGI Proceeds in 2018, July 2020, p. 4.
[9] DEEP, 2020 Plan Update to the 2019-2021 C&LM Plan, March 1, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/8525797c00471adb8525851a006d6e11/$FILE/Final%202020%20Plan%20Update%20Text%20for%203-1-20%20Filing.pdf.
[10] *See* NMR Group, Inc., R1706 Residential Appliance Saturation Survey & R1616/R1708 Residential Lighting Impact Saturation Studies – Final Report, October 1, 2019, p. 8, *available at* https://www.energizect.com/sites/default/files/R1706%20and%20R1616-R1708%20CT%20RASS%20Lighting_Final%20Report_10.1.19.pdf.
[11] Connecticut Energy Efficiency Board, 2019 Programs and Operations Report, March 1, 2020, pp. 4, 5, *available at* https://www.energizect.com/sites/default/files/Final-2019-Annual-Legislative-Report-WEB02262020_2.pdf.

- **Increased grid-scale renewable supply.** In 1998, Connecticut established an RPS to spur investment in renewables by mandating that an increasing portion of the state's electricity needs be supplied by certain types, or classes, of renewable resources. Connecticut's total RPS goal for 2020 now stands at 29 percent of supply, expanding up to 48 percent by 2030.[12] Decreasing GHG emissions was an important—but not the only—goal of the RPS. Some resources with the potential to emit GHGs, waste-to-energy (WTE), biomass, and fuel cells, are included in the RPS, so as to meet other policy objectives, such as avoiding practices that emit higher GHG emissions (such as landfilling), promoting economic development, supporting grid resiliency, and diversifying fuel sources. In 2013, DEEP conducted a study of Connecticut's RPS and determined that about 11 percent of RPS-eligible electricity supply being utilized to meet Connecticut's RPS was coming from zero-carbon sources, while the other 89 percent was coming from biomass and landfill gas projects primarily located out of state.[13] Beginning in 2013, the State began to directly procure grid-scale renewables through competitive Requests for Proposals (RFPs) for long-term power purchase agreements (PPAs).[14] Since that time, The Department has procured 710 MW of grid-scale solar and 1,108 MW of offshore wind over eight separate procurements, harnessing a competitive framework to drive down the price paid by all ratepayers for this clean energy supply.[15]
- **Increased behind-the-meter renewable supply.** In July 1998, Connecticut first authorized net metering for small renewable resources through Public Act 98-28,[16] and expanded the program in 2007 to allow net metering for all customers with Class I facilities with a nameplate capacity of 2 MW or less.[17] The net metering program currently supports distributed generation (DG) across more than 45,000 customers. To accelerate behind-the-meter (BTM) renewable development, Connecticut added supplemental incentives in 2011 when it authorized programs that purchase renewable energy credits (RECs) associated with these net-metered, BTM systems to support additional deployment, like the low and zero emission renewable energy certificate (LREC/ZREC) program run by the EDCs and Residential Solar Investment Program (RSIP) run by the Connecticut Green Bank ("Green Bank"). Since their inception, these programs have led to the installation of 416 MWs of distributed solar and 45 MWs of distributed fuel cells.
- **Preventing the retirement of baseload (nuclear) zero carbon resources.** In 2017, the Independent System Operator of New England (ISO-NE) issued a report indicating that the retirement of the Millstone nuclear facility would subject the region's grid to the risk of rolling

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[12] Conn. Gen. Stat. § 16-245a, as amended by Public Act 18-50 (extending the Class I target to 40% in 2030).

[13] The expectation of future RPS and wholesale energy market revenues alone provided insufficient certainty to finance private development of zero-emission renewable resources. The 2013 RPS Study concluded that direct investment by Connecticut ratepayers, in the form of long-term contracts to purchase energy and/or Renewable Energy Certificates (RECs), would be needed to meet the state's RPS targets with zero-emission renewables.

[14] For purposes of this IRP, "grid-scale" means facilities greater than 2 MW.

[15] The state has also procured 10.6 MW of fuel cells from the Section 127 of Public Act 11-80 solicitation and 52 MW of fuel cells from another procurement.

[16] Public Act 98-28, An Act Concerning Electric Restructuring, *available at* https://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm.

[17] Public Act 07-242, An Act Concerning Electricity and Energy Efficiency, https://www.cga.ct.gov/2007/act/pa/2007pa-00242-r00hb-07432-pa.htm.

black- and brown-outs.[18] At the same time, Millstone's owner, Dominion Energy, Inc., indicated that the plant was unprofitable and would shut down. Under direction from the Connecticut General Assembly, DEEP and PURA conducted an assessment of the Millstone nuclear generating facility, reviewed the facility's financials, and determined that the facility was at risk of retirement given projected low energy market revenues and plant operating costs.[19] Absent viable regional alternatives to support this critical resource, Connecticut entered into a long-term contract with the Millstone facility for 9 million MWh of energy (approximately 36 percent of Connecticut EDCs' load) and all environmental attributes associated with the plant through 2029. By preventing the Millstone retirement Connecticut saved the region from significant negative impacts on the region's electric grid with respect to fuel diversity, energy security, and grid reliability; avoided an estimated $1.8 billion (2017$) in replacement costs that would have been borne by Connecticut ratepayers, and prevented *regional* carbon emissions from increasing by 20 percent.[20]

In total, these trends, programs and investments have contributed to a 36 percent reduction in Connecticut's electricity sector GHG emissions since 1997 when emissions were at their peak.[21] Thanks in large part to energy efficiency investments and BTM solar energy consumed onsite, Connecticut's total electricity demand has declined by 18 percent since 2005—avoiding the need to construct more than 1,100 MW in new power plants, and helping reduce customer bills.[22] Connecticut's RPS Class I requirement stands at 21 percent as of this year, and as of the most recent RPS compliance data provided by PURA, zero-emissions renewables now account for approximately 6 percent of the electricity (in MWh) utilized for RPS compliance in Connecticut.[23] Meanwhile, through direct investment in the form of long-term contracts, Connecticut ratepayers are currently supporting over 600,000 MWh/year of operating grid-scale, zero-emission renewables and more than 9 million MWh/year of zero-carbon nuclear resources, equivalent to nearly 65 percent of the electricity consumed by customers of the state's two EDCs. By 2025, that percentage is expected to increase to 91 percent, or 24.5 million MWh/year, as new offshore wind and grid-scale solar projects that have been contracted but not constructed will come online.[24]

Looking back over the last decade, Connecticut has made significant strides in reducing carbon emissions from the electricity sector through a variety of programs and investments. These programs have been successful in deploying new technologies at scale. Prices for many GHG-reducing

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[18] *See* ISO-NE *Operational Fuel-Security Analysis*, January 17, 2018, p. 50, *available at* https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[19] *See* DEEP and PURA, Resource Assessment of Millstone Pursuant to Executive Order No. 59 and Public Act 17-3, PURA Docket 17-07-32, January 22, 2018, *available at* https://portal.ct.gov/-/media/DEEP/energy/EO59/2018Jan22DraftReportandDeterminationpdf.pdf.

[20] *Id.*

[21] DEEP, 2017 Connecticut Greenhouse Gas Emissions Inventory Supporting Data, 2020, *available at* https://portal.ct.gov/DEEP/Climate-Change/CT-Greenhouse-Gas-Inventory-Reports

[22] ISO-NE, Load Forecast, *available at* https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?load.more=2.

[23] PURA, Final Decision, Docket 18-06-28, July 1, 2020, *available at* http://www.dpuc.state.ct.us/DOCKCURR.NSF/0/211a83eea44855a885258598005ece70/$FILE/180628-062920.pdf

[24] The projected EDC load uses ISO New England CELT data, net of municipal EDC load, for the year 2025 as that is when all current contracted resources are expected to be operational.

technologies—like LED lighting and solar panels—have dropped dramatically during this time, achieving GHG emissions reductions at lower cost over time. Some programs have cost ratepayers substantially more than others per unit of GHG emissions reduced. In some cases, economic development, job growth, and attractive savings for participating customers have also been important drivers of support for these initiatives. There are over 44,000 clean energy jobs in the state, comprising 2.6 percent of all jobs. Clean energy companies contributed $6.5 billion to the gross state product in 2019.

Modeling conducted in 2017-18 for the GC3 charted various pathways to reach the 2050 GWSA target. One such pathway requires Connecticut's electric sector to achieve at least 66 percent zero carbon generation by 2030 to complement similar emissions reduction achievements in the transportation and buildings sectors needed to achieve the 2050 GWSA target.[25] The modeling in Objective 1 below analyzes various scenarios through which Connecticut can achieve its 100% Zero Carbon Target by 2040 as set out in EO 3, using a simulation model of the New England electric grid. These modeling scenarios are intended to highlight contingencies and inform decision-making; they are *not* intended as policy proposals or preferred outcomes. As the modeling below indicates, achieving a 100 percent zero carbon electric supply by 2040 is feasible, and provides for greater flexibility in meeting long-term economy-wide GWSA goals for sectors, such as buildings and transportation, that have been slower to decarbonize to date. The modeling also highlights key contingencies that can affect compliance with GC3 pathway of a 66% zero carbon electric supply to meet the state's 2030 GWSA economy-wide emissions reduction target.

Key assumptions that DEEP used in running the simulation model are discussed first; then a description of the different scenarios tested in the model; and finally, a discussion of the modeling results. The purpose of the IRP pursuant to Connecticut General Statute Section 16a-3a is to assess the state's supply and demand needs in furtherance of GHG emissions reduction goals in a manner that minimizes costs and maximizes benefits. The modeling in this IRP included quantifiable benefits, with other benefits for resources discussed qualitatively. It is important to note that since the IRP modeling is generally based on what is known and knowable, not every potential benefit of each resource is included in the financial modeling results, given that many benefits are dynamic in nature and/or either partially or fully dependent on grid technologies or rate offerings that are not yet available.

Zero Carbon Pathways Modeling Methodology

How much new generation or energy efficiency will be needed to support a 100 percent zero emissions electric supply by 2040, while maintaining a reliable power supply around the clock? How many of the region's existing power plants—especially fossil fuel-fired power plants—can be expected to shut down if Connecticut achieves this decarbonization target? How will these answers change in a "business-as-usual" reference scenario, if Connecticut does not adopt the 100% Zero Carbon Target? Or, if Connecticut meets its GWSA goals for decarbonizing the transportation and buildings sectors by shifting those sectors to electric vehicles, heating, and cooling: a shift that will increase the amount of electric

[25] In order to track compliance with the GWSA, electric sector emissions attributed to Connecticut are currently accounted for based on the regional New England emissions factor. However, because Connecticut has increased its purchases of zero carbon generation and is using those resources for the purposes of GWSA compliance, DEEP is in the process of aligning its GWSA electric sector accounting to reflect the state's investment in zero-carbon resources as progress towards meeting the GWSA mid-term target, as further discussed in Strategy 7.

demand? An economic model provides a way to estimate the answers to these questions, using a computer-generated simulation of the New England electric grid.

Setting the Regional Emissions Target

Connecticut shares an electric grid with the five other New England states: Rhode Island, Massachusetts, Maine, New Hampshire, and Vermont. The New England grid is a network of power plants, and transmission and distribution lines, operated by the Independent System Operator of New England (ISO-NE), that can deliver electricity generated at those plants to customers around the region. A small number of high-voltage transmission lines “tie” the New England grid into Canadian and New York power grids, allowing for imports and exports from those neighboring grids. Residential, commercial, and industrial consumers in Connecticut use approximately 28.8 million MWh of electricity each year, which comprises about 25 percent of the electricity consumption in New England.

Because Connecticut’s grid is integrated with the rest of New England, meeting the 100% Zero Carbon Target in 2040 is not practically achievable independent of the other states in the region. For the purposes of the modeling in this IRP, DEEP developed a Regional Emissions Target for the region by (1) assuming that Connecticut’s share of New England electricity consumption in 2040 would be met 100 percent by zero carbon sources, and (2) consulting with the other New England states and identifying specific assumptions for a zero-carbon or renewable target applicable to the share of electricity consumption for each state. While the New England states share a regional carbon emissions cap under RGGI, some New England states have climate and clean energy policies that compliment and, in some cases, exceed the stringency of the RGGI cap. In this IRP, the model assumes a zero-carbon electric sector target by 2040 for Rhode Island, and the electric sector emissions reductions required in Massachusetts by regulation.[26] The other New England states were assumed to hold emissions constant from 2016 values, the last year consistently available in state emissions inventories at the time of modeling. Accordingly, the Regional Emissions Target met by the Zero Carbon Scenarios (see Figure 1.1, below) in 2040 is not 100 percent zero carbon. The Department acknowledges that climate policy throughout New England is constantly evolving and expects that the Regional Emissions Target will likely be more stringent in future iterations of the IRP.[27]

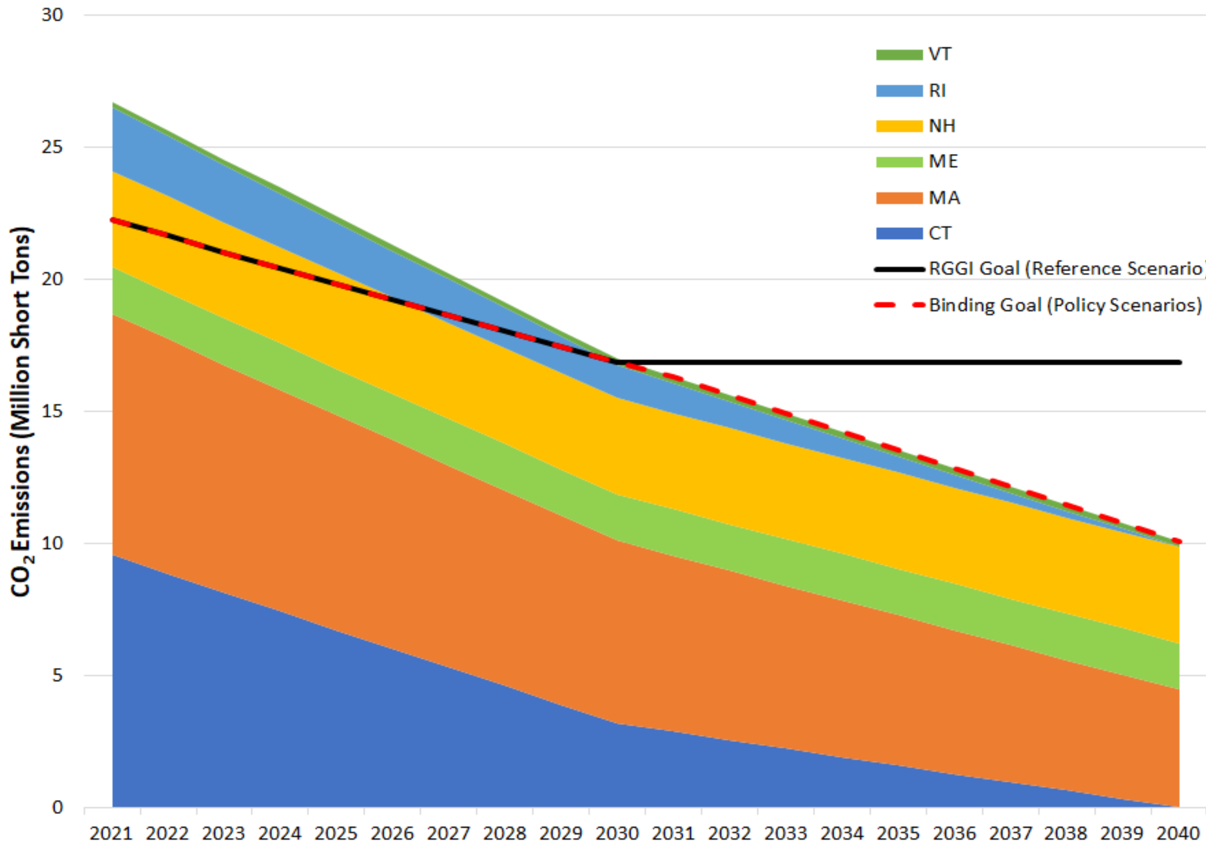
As previously stated, the six New England states have committed to a cap of 18.8 million tons of GHG emissions per year by 2030 (a 30 percent decline) through participation in RGGI, and that number was therefore used as the emissions constraint in the Reference scenario. The Regional Greenhouse Gas Initiative’s cap is only set through 2030, and it is not yet clear how the cap level will change after 2030. Thus, for the Reference scenario, the model assumes that emissions in the New England electricity sector will be at the same level as the RGGI cap in 2030 and will stay at that level through 2040.

This IRP utilized economic optimization modeling software to estimate the quantities (MW and MWhs) of electricity supply resources that would likely retire or need to be added to the New England system each year under a variety of different scenarios to meet the Regional Emissions Target while maintaining

[26] See by 310 CMR 7.74. In general, this regulation requires Massachusetts to acquire 80% of its electricity sales from clean energy resources by 2050.
[27] DEEP finalized these assumptions in November of 2019, and notes that the policies of other states have likely changed since that time.

adequate power supply to meet reliability requirements.[28] The scenarios, described in more detail below, evaluated different combinations of clean energy and efficiency resources that could be utilized to meet the Regional Emissions Target.

Figure 1.1: Annual ISO-NE CO_2 Emissions Comparison, Base Load Scenarios



Additionally, the model was required to meet long-term resource adequacy (reliability) requirements. This means that, given current technology, the model retained some fossil generation to ensure that there are enough resources that can quickly produce power during periods of extreme peak demand in the region, or if a resource suddenly goes offline.

The model also calculates the present value of all existing resources and determines which existing generators would be likely to shut down, or retire, based on differential costs and benefits through 2040. The model runs until it produces a balanced solution of new generating resource additions and retirements, taking into account electric system needs, including reliability, and ratepayer cost. Each time the model is run, it refines the set of new resource options and retirements it places into the system and tracks their economic performance based on anticipated market prices resulting from which resources are selected in the model run. Specifics about projected resource costs are included in Appendix A1. At the end of each run, the model decides how to adjust the current set of new builds and retirements until the model selects an optimal solution.

[28] This IRP used Aurora's Long-Term Capacity Expansion economic optimization modeling software for each scenario. The aggregated GHG emissions targets were translated into MWh of clean energy for inclusion in Aurora's capacity expansion model.

Determining What Counts towards Connecticut's 100% Zero Carbon Target

Another important assumption used in the modeling exercise is what types of resources "count" towards compliance with the 100% Zero Carbon Target. For the purpose of this IRP, DEEP took a multi-step approach—which can be described as a simplified consumption-based emissions accounting method—to determine what should be "assigned" (i.e. credited to Connecticut) towards meeting the 100% Zero Carbon Target. First, the emissions profile from any zero carbon resources that have already been, or would have to be, procured by Connecticut under long-term contracts funded by Connecticut ratepayers to meet the 100% Zero Carbon Target are assigned to the State. This assignment is made even though any RECs associated with those contracts may be either retained or sold by that state's EDCs. Using this GHG consumption-based inventory for the electric sector, the IRP identified the percent of Connecticut's electricity consumption that will be carbon-free over the Reference scenario study period.

After the emission profiles from these contracted resources are assigned to Connecticut load, the emissions from the remaining "unassigned" resources across the region are totaled, and the model assigns each state a share of those emissions proportional to the state's electricity consumption, or load. Connecticut's load share of those emissions from "unassigned" resources in the region is applied to the remaining load needed to be met in Connecticut. To account for the fossil fuel resources needed for fuel security purposes in 2040, additional clean energy is brought online and attributed to Connecticut in the IRP modeling to meet the 100% Zero Carbon Target as required by EO3.

It is important to note that the modeling selects specific types of resource additions (technologies) needed each year to maintain progress towards the Regional Emissions Goal based on reliability and projected cost optimization, as described above. The resulting assignments of these selected resources to Connecticut in each year should be interpreted as the quantity of zero carbon energy the State would need to procure based on those resource cost projections. Any procurements DEEP conducts for resources based on the findings of this IRP to meet the 100% Zero Carbon Target would open to all zero carbon Class I resources, consistent with past grid-scale procurements conducted by the State.

An overview of the modeling results for each scenario is presented below, with more detailed modeling results included in Appendix A3.

The Scenarios Tested in the Model

For the IRP, DEEP tested five scenarios, including a "business-as-usual" Reference scenario which meets the existing regional emissions reduction target established by RGGI, plus four scenarios which use different resource portfolios to meet the Regional Emissions Target (including the 100% Zero Carbon Target) by 2040. Each of the five scenarios is evaluated against two different forecasts of electricity consumption trends: in the "Base" case, electricity consumption continues on the existing trajectory based on current energy policies and primarily relies on the ISO-NE 2019 Capacity, Energy, Loads and Transmission (CELT) Forecast; in the other "Electrification" case, the deployment of electric vehicles and building heating technology triples by 2040, increasing electricity consumption by 18,800 GWh in 2040 relative to the base case.[29] Additional information on the assumptions used to develop the load cases

[29] Each year, ISO New England prepares a projected forecast of the next 10 years' annual capacity, energy demand, loads, and transmission needs. This is used in power systems planning and reliability studies. These studies are all accessible at https://www.iso-ne.com/system-planning/system-plans-studies/celt/

can be found in Appendix A1. In each of the scenarios, the model selects different quantities of zero-emission resources to meet the Regional Emissions Target, including the 100% Zero Carbon Target for Connecticut, with the goal of minimizing associated costs. The zero-emission resource types selected include: offshore wind (OSW), land-based wind (LBW), grid-scale solar photovoltaics (PV), nuclear generation, hydroelectricity imported from Canada, and grid-scale battery storage. The model also relied on some fossil-fueled generation and imports from New York and Canada over existing transmission tie lines to meet the reliability requirements of the region, without exceeding the applicable Regional Emissions Target for each scenario. The ten resulting scenarios are summarized by Table 1.1 below.

Table 1.1: Composition of Study Scenarios

Gross Load Case	Resource Portfolio Scenario		Summary
Base	BR	Reference	Business-as-usual; assumes continuation of existing, "known and knowable" energy policies
	BB	Balanced Blend	Deploys least cost resources to meet the 100% Zero Carbon Target assuming Millstone retires
	BS	BTM Solar PV Emphasis	Assumes an increased amount of behind the meter (BTM) solar is deployed, then deploys least cost resources to meet the 100% Zero Carbon Target
	BM	Millstone Extension	Assumes Millstone continues operating beyond 2029 (the end of Connecticut's current contract) and then deploys least cost resources to meet the 100% Zero Carbon Target
	BT	No Transmission Constraint	Eliminates transmission constraints, then deploys least cost resources to meet the 100% Zero Carbon Target
Electrification	ER	Reference	Business-as-usual; assumes continuation of existing, "known and knowable" energy policies
	EB	Balanced Blend	Deploys least cost resources to meet the 100% Zero Carbon Target assuming Millstone retires
	ES	BTM Solar PV Emphasis	Assumes an increased amount of BTM solar is deployed, then deploys least cost resources to meet the 100% Zero Carbon Target
	EM	Millstone Extension	Assumes Millstone continues operating beyond 2029 (the end of Connecticut's current contract) and then deploys least cost resources to meet the 100% Zero Carbon Target
	ET	No Transmission Constraint	Eliminates transmission constraints, then deploys least cost resources to meet the 100% Zero Carbon Target

Modeling Assumptions

Except where explicitly stated, the assumptions used in this IRP are based on what is currently known and knowable concerning factors such as technological advancements, energy and climate policy, ISO-New England market rules, etc. As the study horizon projects further out into the future, predictability declines, because of how rapidly technologies and policies change. Importantly, modeling assumptions provide a way to test the impact of different contingencies and circumstances on the state's energy supply objectives; the assumptions are not, in and of themselves, expressions of state policy or desired outcomes.

If an assumption was modified to test the sensitivity of that assumption, it is clearly stated. For example, all of the scenarios assume that the Millstone Nuclear Plant located in Waterford, Connecticut, retires when its current ratepayer-backed contract ends in 2029. A 2018 appraisal of nuclear power-generating facilities' financial circumstances found that Millstone was at risk of early retirement based on the generator's disclosed financial statements and insufficient expected market revenues.[30] In order to retain Millstone's efficient and reliable zero carbon energy, Connecticut has entered into a contract through 2029. For these reasons, the modeling assumes that Millstone will continue to be at-risk at the end of its contract and will retire in all scenarios except the Millstone Extension. In the Millstone Extension scenario, the model assumes that Connecticut's contract with Millstone extends beyond 2029. Again, this assumption does not indicate a policy expectation or intent for the state to continue the contract, but is merely tests a hypothetical circumstance in which the nuclear facility continues to operate beyond 2029 (utilizing the current contractual mechanism in place to provide for that continued operation, and assuming there is no wholesale market reform as called for in Objective 2 below), and the consequences of that continued operation for the quantities of other zero carbon resources needed to reach the 100% Zero Carbon Target. The IRP discusses later, in Part II, the policy implications of these modeling insights.

Similarly, the BTM Solar PV Emphasis scenarios adjust the assumed level of rooftop solar that is deployed regionally. Eligible rooftops were used as a proxy to determine the increased BTM solar PV potential, leading more populated states, like Connecticut and Massachusetts, to have much higher growth levels relative to the Reference Scenarios.[31] The annual deployments are not linear, but average to be approximately double what is assumed in the Reference scenarios.

Finally, the No Transmission Constraint scenarios begin with the same resource base as the Balanced Blend scenarios. The adjusted assumption is that constraints on energy transfer among New England zones are relaxed in Aurora. The result effectively turns New England into a "copper sheet" which would allow electricity to flow freely, and the modeling to assume that any transmission-based congestion between Regional System Plan (RSP) zones is eliminated over the IRP study horizon. It is important to note that this scenario does not attempt to predict or include the costs of such transmission upgrades

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[30] Connecticut PURA. Docket 18-05-04. PURA Implementation of June Special Session Public Act 17-3 Interim Decision. December 5, 2018, *available at* http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/7ccd55d05bce0d168525835a00699329/$FILE/180504-120518.pdf

[31] As stated, the Reference scenarios relied on what is known and knowable and in the case of BTM solar PV, assumed deployment was based on ISO-NE's 2019 CELT report.

but rather focuses on the improved efficiency of energy transmission around the region. Further information on the assumptions used in this IRP for all scenarios is included in Appendix A1.

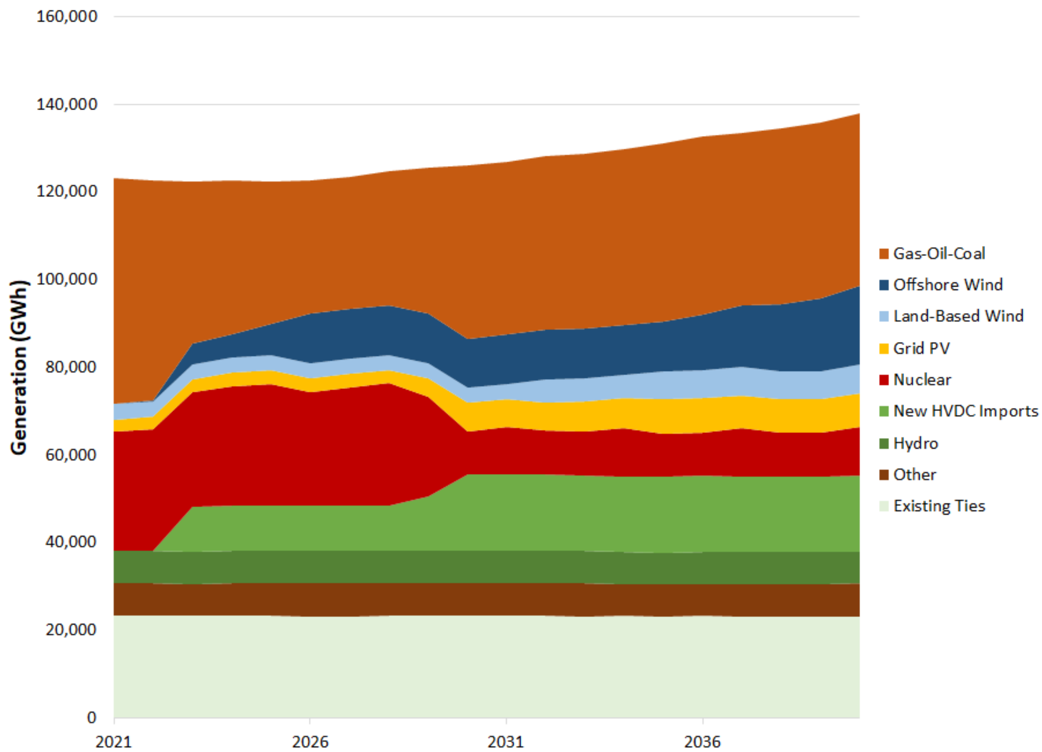
Reference Scenario

The Reference scenario for each load analyzes the "business-as-usual scenario," which assumes the New England states continue with the existing energy policies that were known and knowable to DEEP as of January 1, 2020, and meets the RGGI cap for all years across the region. Figures 1.2 and 1.3 below show regional generation by resource type under this business-as-usual scenario for the base and electrification loads, both of which assume load increases over the modeling horizon.

Under the Reference scenario, the region continues to rely on existing and currently scheduled dispatchable fossil capacity, primarily natural gas, and imports from neighboring regions over existing transmission ties, like New York, to maintain resource adequacy, as demonstrated by Figure 1.2 below. Biomass and WTE resources also (contained in the "Other" category) continue to operate absent alternative waste management policies in the states. New England-based hydroelectricity ("Hydro") continues to provide a steady amount of zero-carbon generation, though siting requirements limit any increases in generation. As the number of annual RGGI emissions allowances decreases in the first half of the modeling period (shown in Figure 1.1 above), renewable generation from zero-carbon resources like land-based wind, offshore wind, and grid-scale solar increase under both loads. Notably, when Millstone is assumed to retire at the expiration of its current contract in 2029, the region will need to fill the zero carbon electricity demand left behind, which the Reference scenario achieves primarily through an additional high voltage direct current cable (HVDC) line importing more hydroelectricity from Canada.32 Additional grid-scale solar, LBW, and OSW generation also help fill the gap after 2029 to maintain the RGGI target emissions levels, and are balanced by dispatchable, fossil generation to continue maintaining reliability. It should be noted that the model did not allow for any new dispatchable, fossil generation additions over the modeling period.

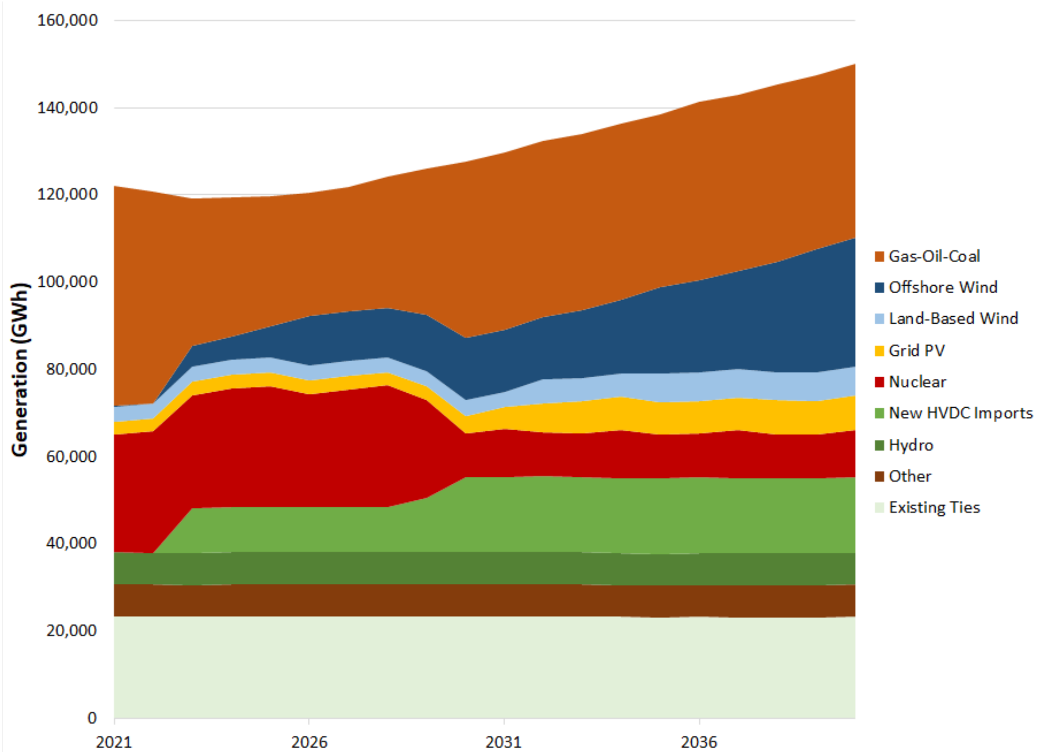
[32] The assumption in this IRP that Millstone would retire in 2029 absent a contract extension is based on the Resource Assessment and Appraisal conducted to satisfy the requirements of Executive Order No. 59 (July 25, 2017) and June Special Session Public Act 17-3, which found that "Millstone Station's profitability is highly correlated with the cost assumptions highlighted in Dominion's and others' comments, and that, when some adjustments are made, the financial viability of Millstone's continued operation could be at risk." Accessible at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/a2d566dfd5533fed8525822700725e33/$FILE/DEEP-PURA%20FINAL%20Report%20and%20Determination%202-1-18.pdf

Figure 1.2: Annual Regional Generation, Base Load Reference Scenario[33]



[33] The "Other" category aggregates many different technologies. The majority of "other" is wood waste and municipal solid waste units.

Figure 1.3: Annual Regional Generation, Electrification Load Reference Scenario



Under this business-as-usual scenario, in addition to relying upon a new HVDC line to import power from Canada, Connecticut would need to procure new resources to come online in 2029 in order to meet the RGGI goals. Using a least-cost deployment strategy employed by the model, these procurements would begin with grid-scale solar balanced by storage, then land-based wind in 2032 and offshore wind in 2036.[34] See Figures 1.4 and 1.5 below. While all capacity additions are limited to zero carbon resources, it is important to note that even under a business-as-usual future, these resources could face siting challenges in the forms of environmental conservation and land-use restrictions, public opposition (i.e. the recent conflict around the New England Clean Energy Connect (NECEC) transmission line planned to bring approximately 1 GW of hydroelectricity from Canada, through Maine, down to Massachusetts), and industry opposition. Careful planning with lead times sufficient to consider stakeholder input and public education can help hedge against the risk of delays or prevention of buildouts, as discussed in Objective 4.

[34] For a more detailed explanation of Aurora's economic optimization modeling functionality, see Appendix A1.

Figure 1.4: Incremental Resource Capacity Allocation to Connecticut, Base Load Reference Scenario

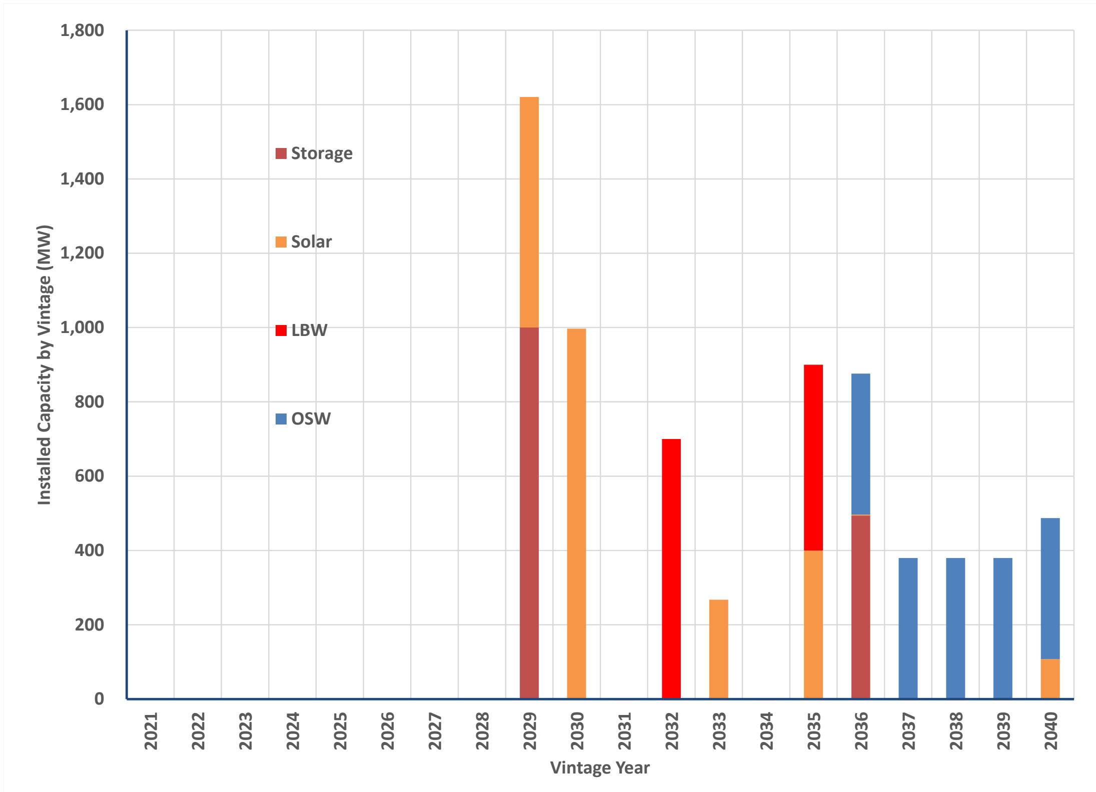
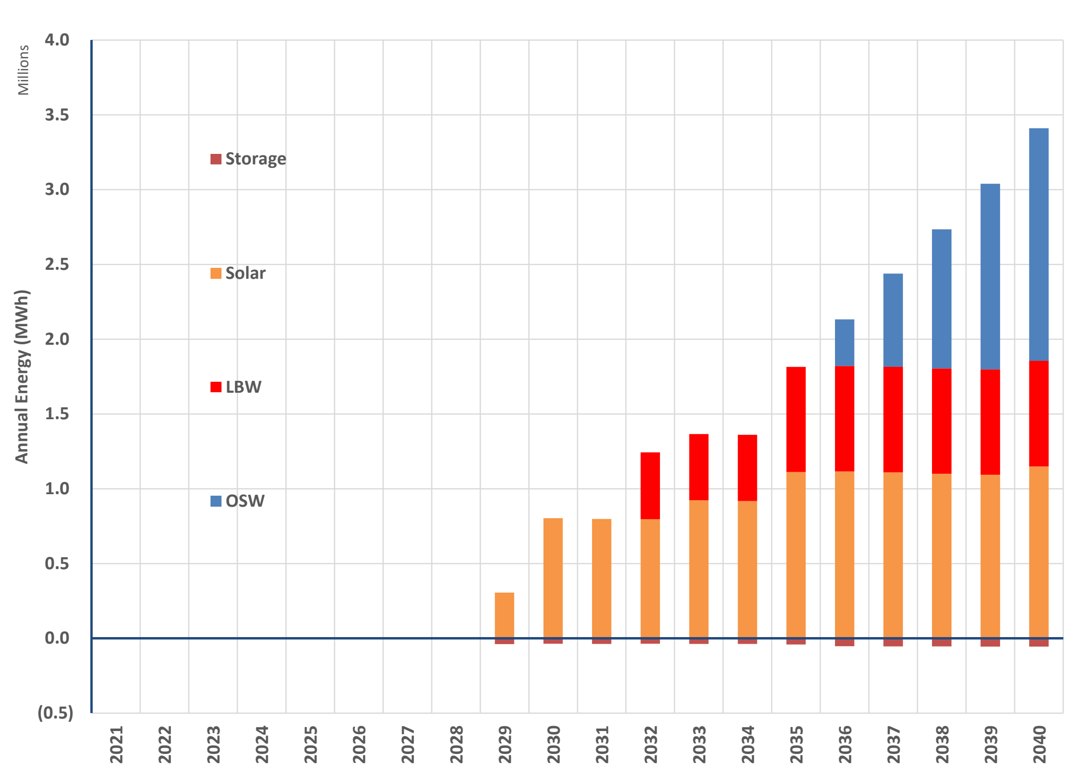


Figure 1.5: Incremental Resource Energy Allocation to Connecticut, Base Load Reference Scenario



Zero Carbon Policy Scenarios

Aside from the Reference scenario, all of the scenarios considered in this IRP are Zero Carbon Policy scenarios. The Zero Carbon Policy scenarios represent various pathways towards meeting the region's aspirational emissions reduction goal for Connecticut's electric supply. This means that the overall 2040 emissions cap in these scenarios reflects the combined emissions targets from the six New England states. This cap is roughly equal to 10 million short tons in 2040, as previously shown in Figure 1.1. The aggregated GHG emissions targets were translated into MWh of clean energy for inclusion in the model's capacity expansion modeling. Because not all states have zero carbon electric supply goals as Connecticut does, the model allowed some emitting resources to continue to operate over the modeling horizon.

The objective of the Zero Carbon Policy scenarios was to maintain reliability and meet the necessary Regional Emissions Target in each year while minimizing the overall costs of achieving those goals. The allocation of zero carbon resources in each year works backwards from 2040 to ensure that the Regional Emissions Target is met. Because the model selects resources to meet the Regional Emissions Target, allocations of resources specifically to Connecticut were determined after the model selected resources for the scenario.[35] None of these scenarios were selected to represent a preferred policy path to meet the 2040 target—but rather to test the impact of various contingencies and circumstances (such as the retirement of Millstone, or procurement of transmission or larger amounts of behind-the-meter solar) on the quantity of different types resources that could be needed, and associated cost, to meet the goal.

[35] Further discussion of resource allocation ratios can be found in Appendix A4.

Key Findings

The Zero Carbon Policy scenarios demonstrate that the 100% Zero Carbon Target for Connecticut's electric supply is achievable by 2040 under many different conditions and pathways, and that the State is already well on its way to achieving this goal thanks to existing clean energy procurements and energy efficiency investments. As noted above, through existing investments, approximately 65 percent of Connecticut's electricity supply is currently generated by zero carbon resources such as wind, solar, and nuclear. Broadly speaking, each scenario shows similar trends under the two different load levels, with the exceptions that the Electrification Load scenarios will generally require (1) larger quantities of new clean energy resources (offshore wind in particular) to meet the higher load and avoid emissions, and (2) fewer retirements of existing fossil facilities (mostly natural gas) that can provide energy immediately during periods of low renewable generation or especially high demand. Importantly, as batteries and other forms of storage become more economic, they will be able to take on more of this role.

Each pathway (i.e. scenario) highlights certain tradeoffs that Connecticut will need to carefully weigh in order to balance achieving the 100% Zero Carbon Target for electric supply with the State's other energy and environmental policies. For example, the Balanced Blend scenarios select the lowest cost portfolio of clean energy resources needed to achieve the 100% Zero Carbon Target, assuming that Millstone retires in 2029. Notably, this scenario provides for a progressive pace of new renewable builds to meet the 2040 target—highlighting the importance to moderate rate impacts for Connecticut ratepayers—but does exhibit a dip in emission reductions in the early- to mid-2030s, below the 66 percent zero carbon electric sector planning target modeled by the GC3 in 2018. Earlier procurements of renewables would be needed to avoid this temporary dip, in the event a Millstone retirement becomes likely.

Comparatively, the Millstone Extension scenarios demonstrate that if Millstone continues to operate through 2040, this will (1) reduce the total cost of meeting the 100% Zero Carbon Target by offsetting the need for new incremental resources, (2) allow Connecticut to meet emissions reductions targets in all of the modeled years through its continued generation of zero carbon electricity, and (3) allow more fossil units to retire throughout the region than under the Balanced Blend. This scenario assumes, however, that Connecticut continues to rely on nuclear energy to meet about half of its zero carbon energy policy targets.[36] Establishing a regional mechanism for valuing the reliability and zero carbon aspects of Millstone's electricity generation is one alternative to provide for the continued operation of this resource beyond 2029; in that event, the share of nuclear energy contributing to the 100% Zero Carbon Target would decrease, and additional investment in renewables would be needed to achieve that target.

This IRP also considers how increased deployment of distributed generation resources throughout the region, specifically behind-the-meter (BTM) solar PV, would affect a least-cost portfolio of resources needed to meet the 100% Zero Carbon Target. These scenarios follow a path similar to the Balanced Blend, meeting the 100% Zero Carbon Target by 2040, but falling short in the interim years due to Millstone's retirement. The key difference is that the overall cost of the resource portfolio is higher because BTM solar PV is a more expensive technology on a cost-per-unit basis than other zero carbon

[36] Note that this scenario assumes that, due to the flawed regional energy markets, Connecticut alone will continue to support a resource that provides critical reliability to the region.

resources. Additional BTM solar PV avoids the need for some OSW development in the later years, but not enough to offset the higher costs of the BTM solar PV technology.

Finally, all scenarios indicate escalating levels of curtailment as the amount of intermittent renewable capacity increases. Variable energy resources (VERs) like offshore wind turbines or solar panels cannot be turned off or on (i.e., dispatched) like traditional capacity. If the sun is shining, and the wind is blowing, they are generating power; otherwise, they are not. The New England grid can only distribute so much capacity at once, so if there is more energy being produced than can be used because the system cannot move the power to the load—absent investment in additional transmission, or energy storage--some energy must be curtailed, or "spilled." Spilled energy reduces the revenue a resource receives from the energy market, and therefore increases the costs that the resource must recover through alternative mechanisms, such as state-jurisdictional procurements.[37] These insights highlight the importance of low- or no-emission strategies to reduce spillage and reliably integrate intermittent renewables, through the use of demand response, energy storage, and transmission investment.

As an example, the No Transmission Constraint scenarios ("Transmission scenarios") test how much renewable "spillage" could be avoided through upgrades to the transmission system to handle the increased power production during certain hours, avoiding wasted energy while still meeting the 2040 Emissions Reduction Target. The scenarios found that while elimination is not fully possible due to weather-based variables, reducing transmission constraints could significantly reduce costs to ratepayers by avoiding the need to build additional clean energy resources.[38]

The specifics of each Zero Carbon Policy scenario are further discussed below. Costs in the "Key Findings'' boxes (provided for each scenario and load pairing) are presented as the net present values over the study period (2021-2040) in each scenario compared to the Reference scenario, calculated using a seven percent nominal discount rate. The composition of each scenario's present value costs is shown in Figures 1.6 and 1.7 below, relative to each load level's Reference scenario (i.e. the Reference scenario is the baseline). "Total Ratepayer Cost", identified by the red and grey circles, are inclusive of all costs and benefits except for "Societal Cost of GHG Effects" (i.e. avoided costs of GHG effects). "Total Societal Cost", identified by the yellow and black triangles, include "Societal Cost of GHG Effects" and therefore demonstrate a lower net present value cost for each scenario. These amounts reflect the total cost above the market cost of a future that does not endeavor to meet the carbon target. Additional information on each cost component can be found in Appendix A4.

[37] ISO-NE. 2019 Economic Study: Offshore Wind Integration. June 30, 2020.
[38] As noted above in this section, the costs of eliminating transmission constraints were not modeled in this scenario.

Figure 1.6: Base Load Scenarios Present Value Costs Relative to the Reference Scenario

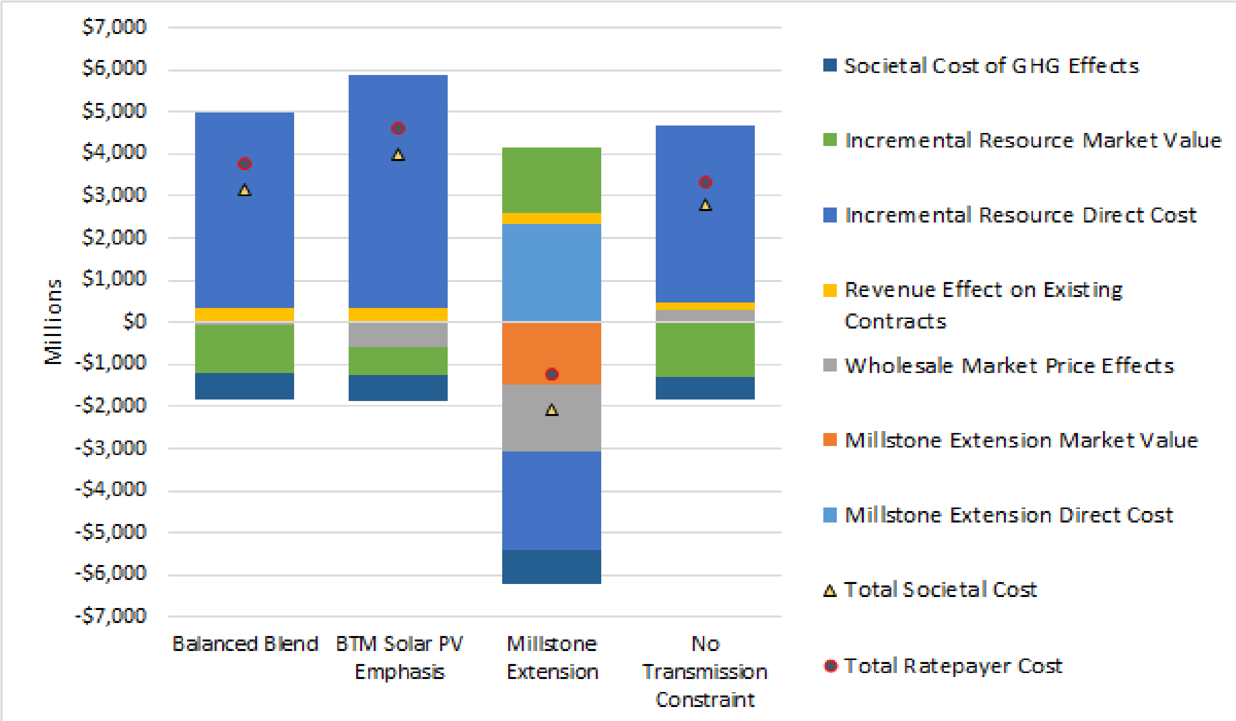
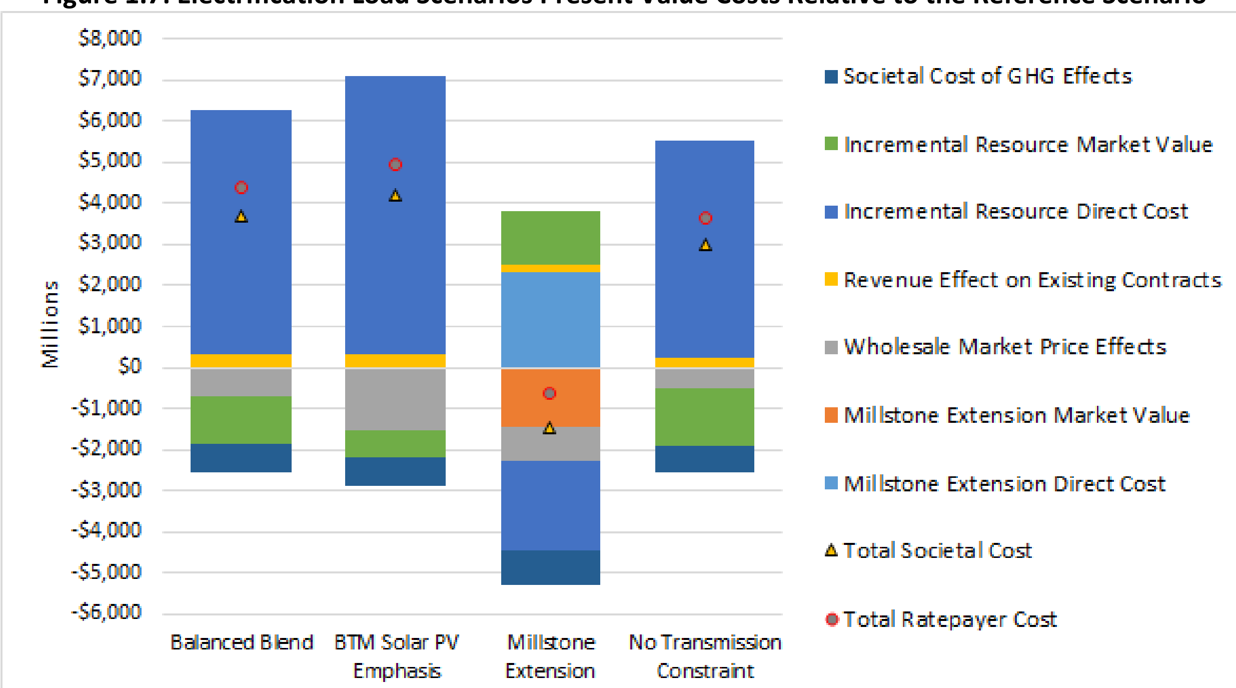


Figure 1.7: Electrification Load Scenarios Present Value Costs Relative to the Reference Scenario



Balanced Blend Scenarios

The Balanced Blend scenarios select the lowest cost portfolio of resources needed to meet the Regional Emissions Target, inclusive of a 100% Zero Carbon Target for Connecticut's electric supply, and assumes that Millstone Nuclear Power Station (”Millstone”) retires in 2029 at the end of the existing Connecticut contract period.

Base Load Balanced Blend (BB) Scenario

When modeled under the Base Load, New England will need to install approximately 30 GW of clean energy resources in order to meet the Regional Emissions Target. Connecticut alone will need to procure approximately 8.5 GW of these additions in order to meet the 100% Zero Carbon Target. The majority of both regional and Connecticut additions under this scenario are offshore wind and grid scale solar.[39]

Key Findings: Base Load Millstone Extension

- Present Value Total Societal Cost: $3.15 B
- Present Value Total Ratepayer Cost: $3.76 B
- 2040 zero carbon goal will be met, though some interim years fall short.
- 4.8 GW Connecticut clean energy procurements by 2040
- 8.3 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~25% by 2040 due to transition from high variable cost resources to high fixed cost resources
- Weather effects, seasonal demand, and transmission constraints will result in the loss of 6.8% of wind and grid-scale solar generation.

The Base Load Balanced Blend scenario successfully meets the 100% Zero Carbon Target for electric supply, as shown by Figure 1.8, which displays the metric tons of CO_2-equivalent that must be displaced each year over the study horizon (brown line), and the composition of resources that will meet each year's CO_2-equivalent emission target. The amount of CO_2 that must be displaced each year follows a simple, linear path until the kink in the brown line (“Resources Required for Compliance”) at 2030, which represents the interim electric sector emissions reduction target estimated by the GC3.[40] A new linear path continues from that point until the 2040 100% Zero Carbon Target amount of CO_2-equivalent necessary to achieve a zero carbon electric supply. Details on the key to Figure 1.8 include:

1. Connecticut (CT) Existing Contracts: fixed amounts of zero carbon energy from existing contracts, including the Millstone contract and existing grid-scale solar and wind procured through DEEP's grid-scale procurements
2. CT BTM Solar: Connecticut's portion of BTM Solar PV
3. HQ Imports: amount of hydropower assumed to come online through an additional import line
4. Current Vintage Allocations to CT: the amount of new resources allocated to Connecticut in that given year to meet the 100% Zero Carbon Target. A breakdown of the cumulative resources needed for each year is included in Table 1.2.
5. Prior Vintage Allocations to CT: the cumulative amount of resources brought online to meet the 100% Zero Carbon Target allocated to Connecticut in previous years

[39] As previously stated, the modeling optimizes resource selections to minimize costs and maintain resource adequacy. Modeled procurement schedules (e.g. Table 1.2) in each scenario present the necessary quantities of clean energy capacity Connecticut would need under the set of assumptions used for that scenario. In reality, procurements conducted by the State would be open to all eligible zero carbon Class I resources.

[40] Governor's Council on Climate Change. 2018. *Building a Low Carbon Future for Connecticut: Achieving a 45% Reduction by 2030.* Available at: https://portal.ct.gov/-/media/DEEP/climatechange/publications/BuildingaLowCarbonFutureforCTGC3Recommendationspdf.pdf

6. Current Vintage Allocations to Rest of Pool: the amount of new resources allocated to other states in the region

The blue line (“Gross CT Load”) shows Connecticut’s gross energy load, which tightens against the brown line as it approaches the 2040 goal year, demonstrating how the proportion of Connecticut’s gross load from clean energy grows each year.

Figure 1.8: Connecticut Incremental Resource Allocation, Base Load Balanced Blend Scenario

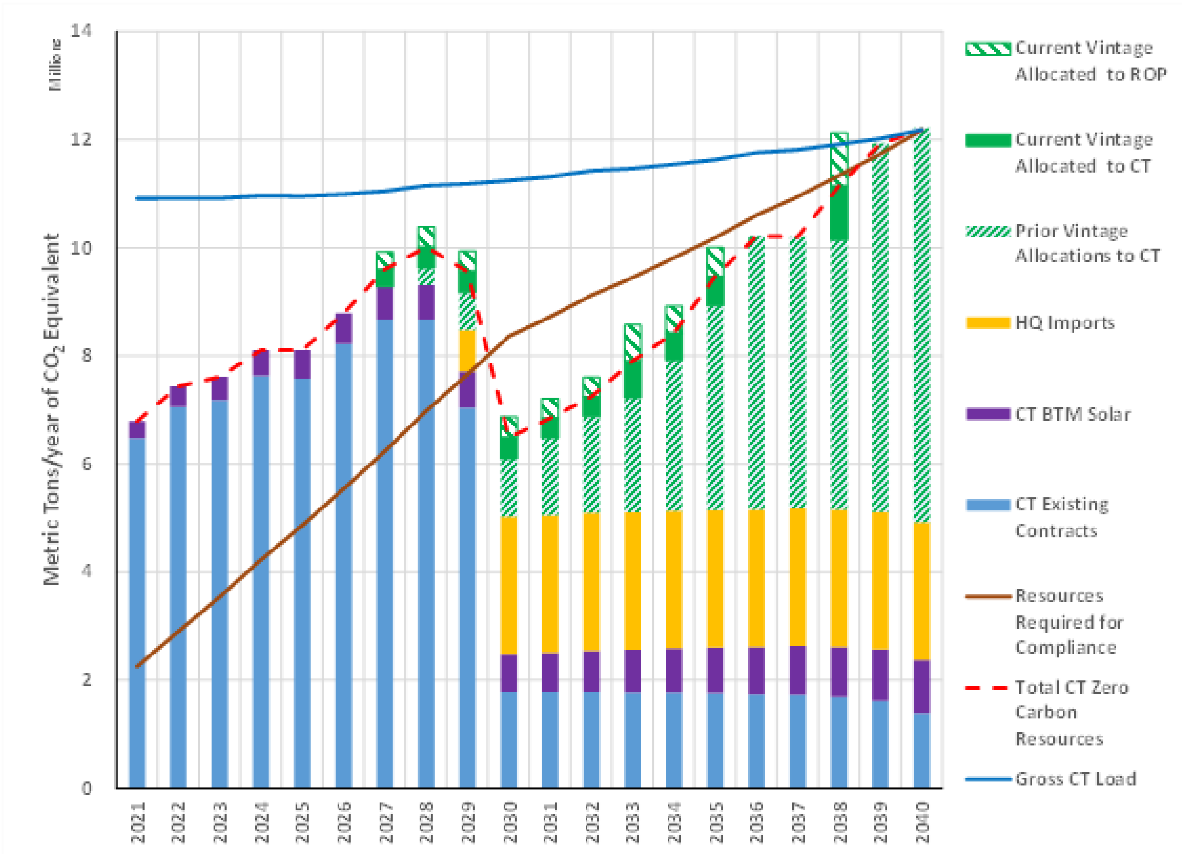


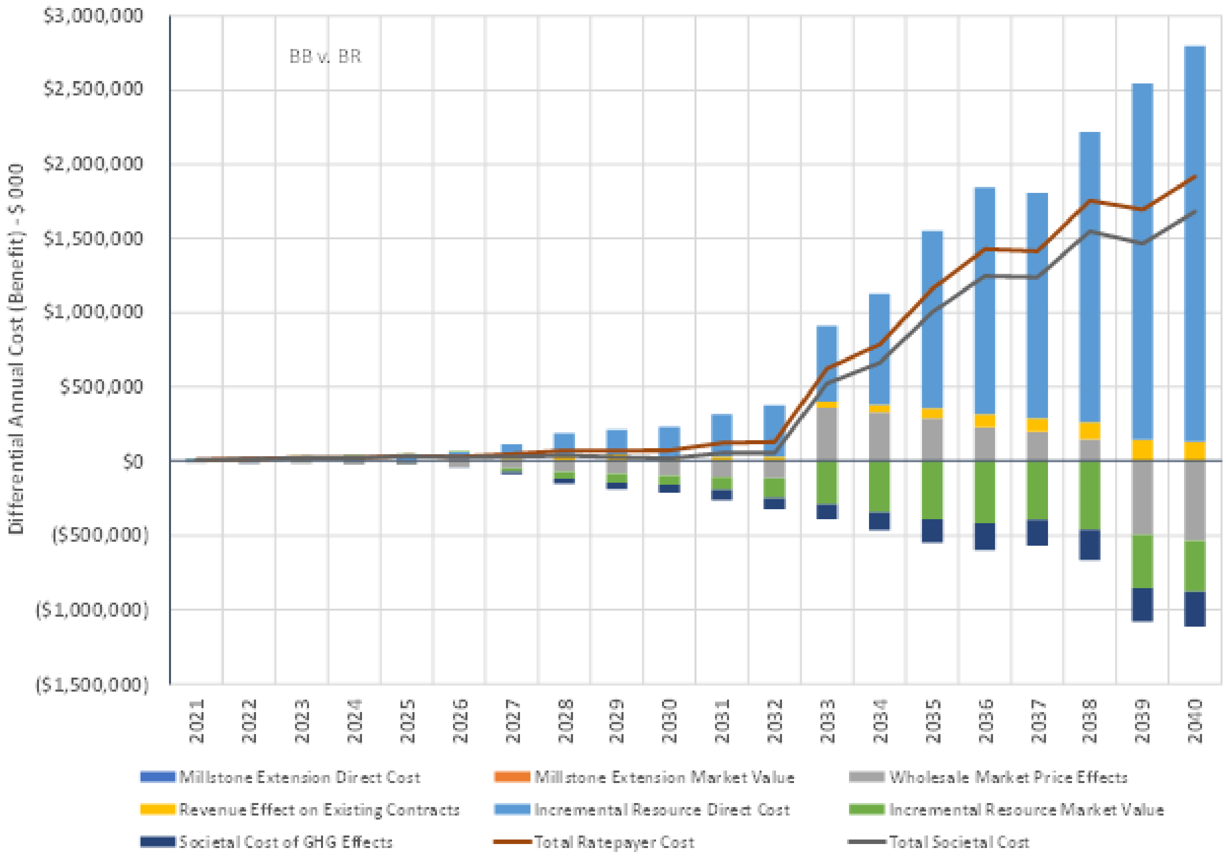
Table 1.2: Cumulative Incremental Resource Capacity, Base Load Balanced Blend Scenario

Calendar Year	Cumulative Incremental Resource Allocation			
	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	432	0	0
2028	0	933	0	0
2029	0	1,432	0	0
2030	0	1,928	0	0
2031	121	2,421	0	0
2032	372	2,912	0	0
2033	372	3,401	352	0
2034	372	3,384	352	388
2035	372	3,399	352	1,165
2036	372	3,382	352	1,745
2037	373	3,365	352	1,745
2038	542	3,348	352	2,545
2039	588	3,332	352	3,344
2040	1,060	3,316	352	3,745

Under the Base Load Balanced Blend scenario, Connecticut exceeds the annual goal in the first half of the study period, satisfied by Connecticut's existing clean energy contracts, including the continued operation of Millstone. New clean energy resources begin to appear in 2027 and scale up through the mid-2030s to replace the Millstone capacity. Connecticut falls short of meeting the 2030 goal for the electric sector identified by the GC3 in 2018. This does not necessarily mean that the state would fall short of meeting the GWSA economy-wide target for 2030, but doing so would require greater emissions reductions to be achieved in the transportation and buildings sectors. The state does meet the 2040 zero carbon electric goal under this scenario.

The costs of meeting the Base Load Balanced Blend scenario over business as usual (i.e. the Reference scenario) are outlined in Figure 1.9. If Connecticut procured zero carbon resources at a quicker pace than demonstrated in Table 1.2 to achieve the 2030 GC3 goal, then the costs would be higher than what is presented in Figure 1.9. A full discussion of each cost category can be found in Appendix A4.

Figure 1.9: Differential Annual Costs – Base Load Balanced Blend Scenario v. Base Load Reference Scenario



As illustrated by Table 1.2, under the Base Load Balanced Blend scenario, 2027 is the first year that Connecticut would need to have new zero-carbon resources ready to operate. Figure 1.9 demonstrates how the net cost increases as new resources are brought online. The increases are partially offset by the societal avoided cost ("Societal Cost of GHG Effects") associated with a reduction in CO_2 emissions, and the value of energy and capacity revenues associated with zero carbon resources ("Incremental Resource Market Value"). The projected net cost to Connecticut ratepayers to purchase incremental resources needed to achieve the 100% Zero Carbon Target over the study period under the Base Balanced Blend scenario is $3.8 billion. This amount is estimated to be reduced by $600 million if the societal cost of carbon is included for a net societal cost of $3.2 billion. It is also important to note that this cost does not include the full cost of demand side programs implemented in the Balanced Blend scenarios. The scenarios under the Base load do not include consideration of demand side management (DSM) programs beyond business-as-usual. The net cost to ratepayers could be lowered with additional investment in DSM programs. It is clear that there is significant potential for additional DSM in Connecticut, which is further discussed in Objective 5.

Electrification Load Balanced Blend (EB) Scenario

Under the Electrification Load, Connecticut will need to procure more clean energy resources in order to meet both increased load and the 100% Zero Carbon Target. Like the Base Load Balanced Blend scenario, the Electrification Load Balanced Blend scenario relies primarily on the large-scale deployment of offshore wind and grid-scale solar resources, though OSW deployment for Connecticut increases by 50 percent over the Base Load Balanced Blend, shown by Table 1.3.

Key Findings: Electrification Load Millstone Extension

- Present Value Total Societal Cost: $3.7 B
- Present Value Total Ratepayer Cost: $4.4 B
- 2040 zero carbon goal will be met, though some interim years fall short.
- 10.9 GW Connecticut clean energy procurements by 2040
- 7 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~26% by 2040 due to transition from high variable cost resources to high fixed cost resources
- Weather effects, seasonal demand, and transmission constraints, will result in the loss of 11.6% of wind and grid-scale solar generation.

An additional and critical difference between the two load cases is that the Electrification Load Balanced Blend scenario retires fewer fossil resources across the region. The deployment of significantly more VERs to meet both the higher energy demand and carbon targets in the Electrification Load scenarios means that energy production is less stable and reliable than business-as-usual. The modeling used "known-and-knowable", industry-accepted assumptions around wind and solar production over the study horizon, but these assumptions come with some uncertainty, particularly in the mid- and long-term.[41] The Department anticipates advancements with technologies like battery storage and renewable hydrogen could help balance variable zero carbon resources and better achieve the 100% Zero Carbon Target and will continue to assess the advancement of these technologies in future IRPs.

New England's regional independent system operator, ISO-NE, maintains standards for reliability, which require a specific amount of resources, called reserves, that can quickly turn off and on to meet demand during particularly high peaks, or when a generator shuts down unexpectedly.[42] Higher load results in a higher peak, and therefore also means a higher reserve requirement. Additionally, in this IRP, meeting the carbon constraints under the Electrification load requires more renewable VERs, as discussed above. These resources have a more variable output, often heavily influenced by weather conditions, and must therefore be balanced with operating reserves. While some of these reserves can be met with demand response (DR), hydropower, and battery storage, the majority will be met with fossil resources because these fuel types can be readily and continuously dispatched to meet demand, unlike VERs such as wind and grid-scale solar. Figures 1.10 and 1.11 show how the modeling meets these reserve needs under the Base and Electrification load cases. Despite having fewer fossil plants retire, the Electrification Load Balanced Blend scenario does meet a slightly larger portion of the reserve requirement with non-fossil resources than the Base Load Balanced Blend, particularly driven by increased battery storage additions. Further details on these reserve resources can be found in Appendix A3.

[41] More information on the assumptions used in modeling resource generation can be found in Appendices A2 & A3

[42] More information on ISO-NE Operating Reserve Requirements can be found in Appendix A1

Figure 1.10: Operating Reserve Mix by Scenario in 2040, Base Load Case

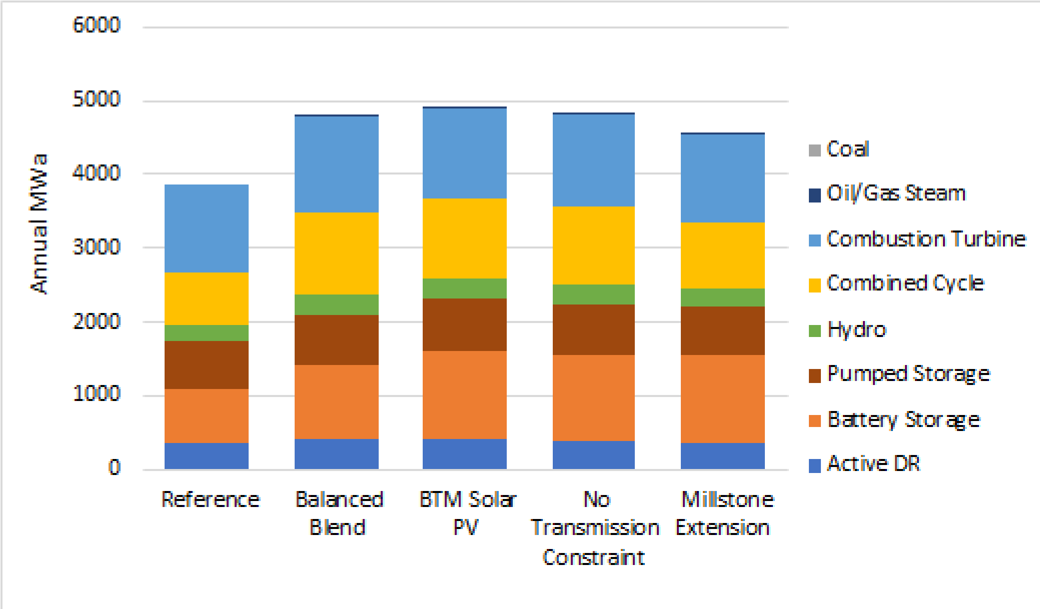


Figure 1.11: Operating Reserve Mix by Scenario in 2040, Electrification Load Case

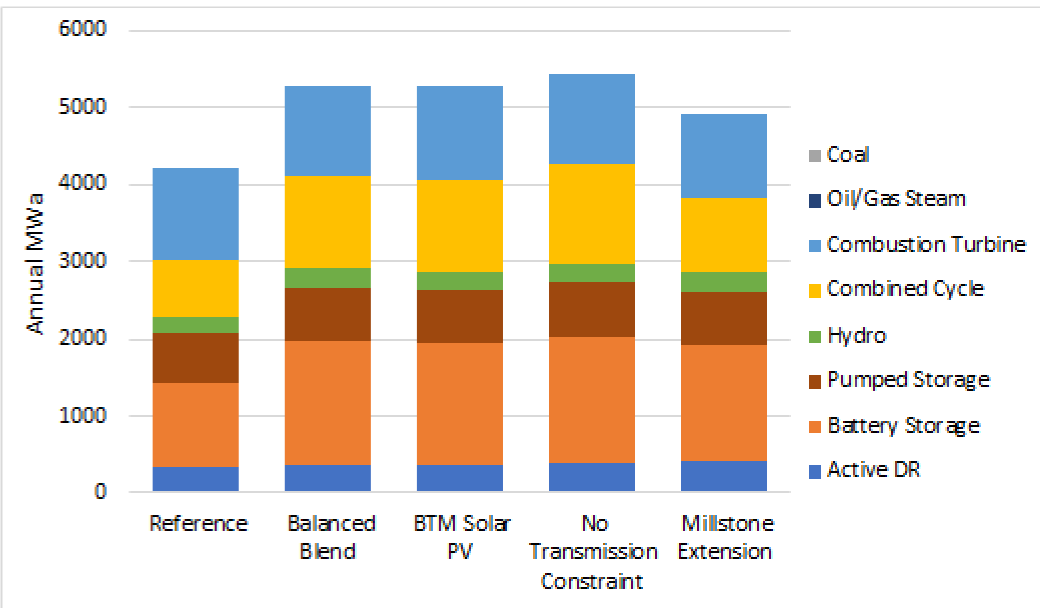


Figure 1.12 shows how the 100% Zero Carbon Target for Connecticut's electric supply will be met under the Electrification Load Balanced Blend scenario. Similar to the Base Load Balanced Blend scenario, Connecticut meets the annual targets through the assumed retirement date of Millstone in 2029, then misses annual targets after 2030 before ultimately meeting the 100% Zero Carbon Target in 2040. As in the Base Load Balanced Blend, Connecticut would need an accelerated procurement schedule in order to also meet the GC3 2030 66% pathway. Cumulative resources allocated to Connecticut each year are included in Table 1.3.

Figure 1.12: Connecticut Incremental Resource Allocations, Electrification Load Balanced Blend Scenario

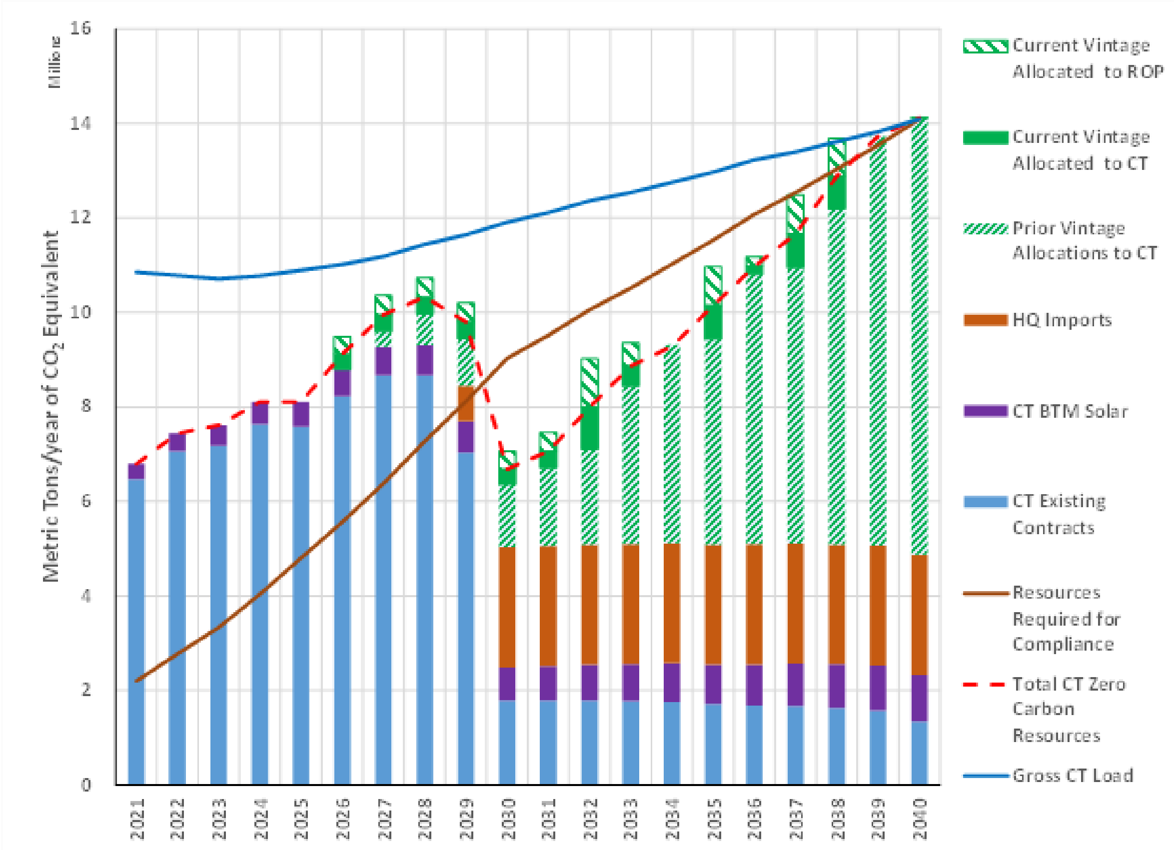
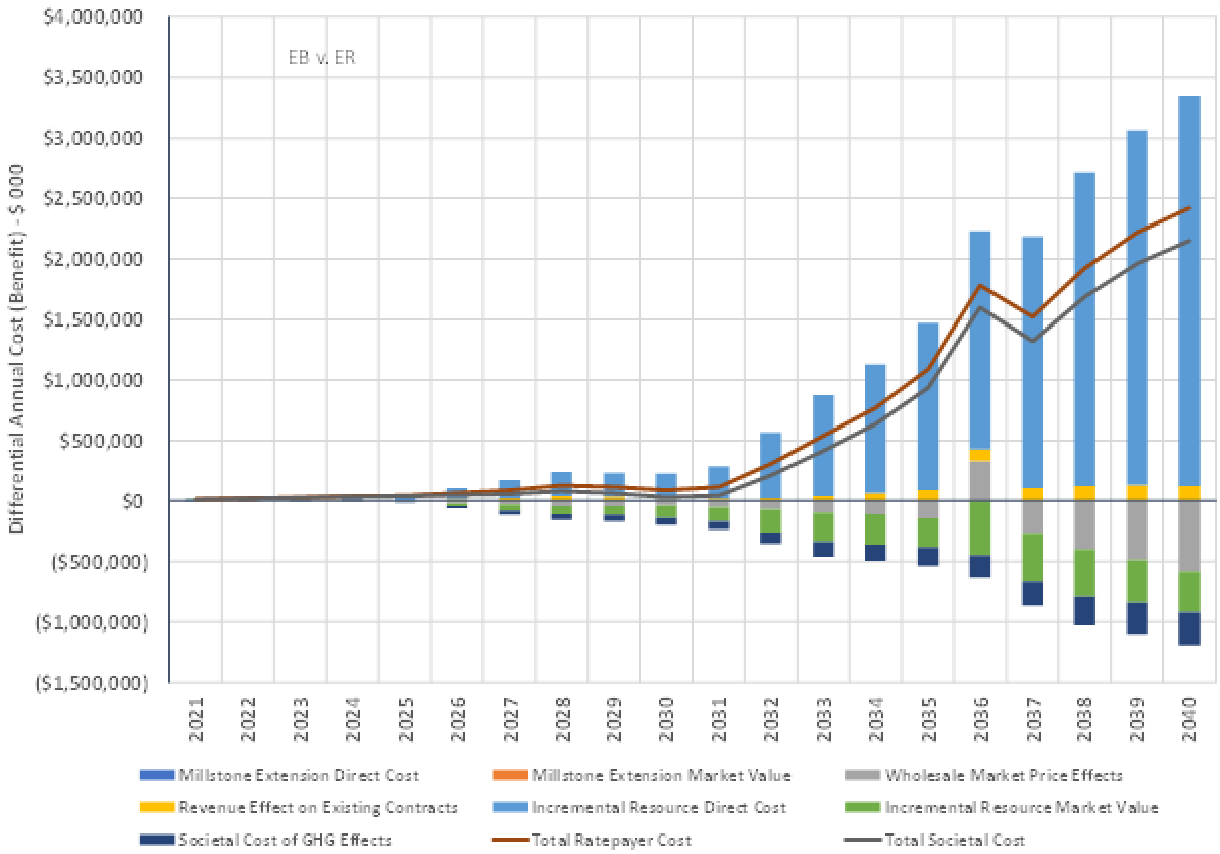


Table 1.3: Cumulative Incremental Resource Capacity, Electrification Load Balanced Blend Scenario

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	425	0	0
2027	0	887	0	0
2028	0	1,347	0	0
2029	0	1,805	0	0
2030	232	2,260	0	0
2031	232	2,713	0	0
2032	464	2,900	325	358
2033	464	3,146	325	892
2034	929	3,131	325	1,245
2035	929	3,115	325	1,962
2036	929	3,100	557	2,503
2037	1,139	3,084	557	3,077
2038	1,603	3,069	557	4,208
2039	1,603	3,054	557	5,152
2040	1,603	3,045	557	5,710

Annual differential costs for the Electrification Load Balanced Blend scenario against the Reference scenario are shown in Figure 1.13. Trends are similar to the Base Load Balanced Blend scenario, with net costs increasing starting in 2026, when Connecticut must procure new zero carbon resources. The increase is again partially offset by the societal cost associated with a reduction in CO_2 emissions and the market value of the zero carbon resources. The general trend continues through 2040. The net cost to Connecticut ratepayers to purchase incremental resources needed to achieve the 100% Zero Carbon Target over the study period under the Electrification Load Balanced Blend scenario is projected to be $4.4 billion. The inclusion of societal benefits from avoided CO_2 emissions reduces that projected cost about $700 million for a net societal cost of $3.7 billion. Again, this cost does not include demand-side program costs, but it should be noted that the Electrification Load case does include a higher level of assumed energy efficiency associated with ASHP deployment than the Base Load. As previously stated, additional investment in DSM could potentially reduce ratepayer costs. The next Comprehensive Energy Strategy will seek to identify the optimum level of future investment in DSM programs that would achieve these ratepayer cost savings. In addition, if Connecticut accelerated the procurement schedule outlined in Table 1.3 to meet the 2030 GWSA goal, the costs would increase.

Figure 1.13: Differential Annual Cost – Electrification Load Balanced Blend Scenario v. Electrification Load Reference Scenario



Millstone Extension Scenarios

The Millstone Extension scenarios select the lowest cost portfolio of resources needed to meet the Regional Emissions Target, including Connecticut's 100% Zero Carbon Target, and assume that Millstone continues operating beyond its current 2029 retirement date. As further set forth in Objective 2 and the strategies in Part II below, if Millstone were to continue to operate beyond 2029, it should be supported regionally through a reformed ISO-NE wholesale market, or by some other regional mechanism. The complexities of that modeling were beyond the scope of this IRP; thus, the Millstone Extension scenarios are based on an assumption that the current contract with Millstone is extended. As further set forth below, this IRP does not recommend that Connecticut's electric ratepayers should take on that burden on behalf of the region again.

Base Load Millstone Extension (BM) Scenario

Under the Base Load, the Millstone Extension scenario reduces the need to purchase OSW and other zero carbon resources, and thus reduces costs compared to the Balanced Blend scenario. The model begins selecting grid scale solar additions for Connecticut in 2030, and pushes other procurements back several years as compared to the Balanced Blend scenario. Under the Base Load Millstone Extension scenario, Connecticut is able to meet the annual CO_2 emissions reduction target amount in every year over the modeling horizon, including the 2030 electric sector goal set by GC3, as shown by Figure 1.14. Millstone's existing contract is aggregated with other Connecticut clean energy contracts ("CT Existing Contracts") through early 2029 because it is an existing contract. A modeled extension of that contract is then demonstrated by the Millstone Extension bar through 2040. Under this scenario, which assumes a contract extension that assigns all of Millstone's environmental attributes to Connecticut as the current contract does, Connecticut would need just over half of the clean energy additions that are needed under the Base Load Balanced Blend scenario to meet each year's target. Table 1.4 includes the resources allocated to Connecticut each year.

Key Findings: Base Load Millstone Extension

- Present Value Total Societal Cost: -$2.05B
- Present Value Total Ratepayer Cost: -$1.25B
- 2040 zero carbon goal will be met, as are interim annual targets
- 4.8 GW Connecticut clean energy procurements by 2040
- 8.3 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~22% by 2040 due to transition from high variable cost resources to high fixed cost resources

Figure 1.14: Connecticut Incremental Resource Allocation, Base Load Millstone Extension Scenario

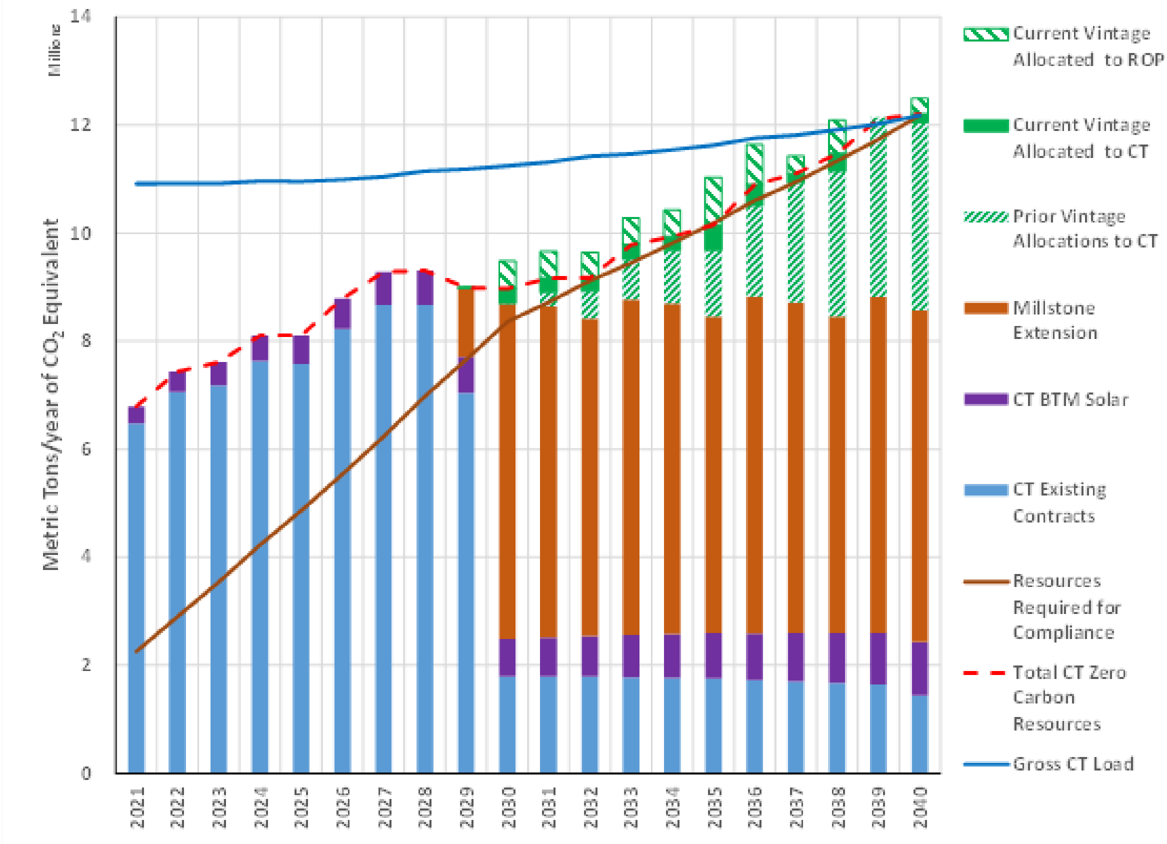


Table 1.4: Cumulative Incremental Resource Capacity, Base Load Millstone Extension Scenario

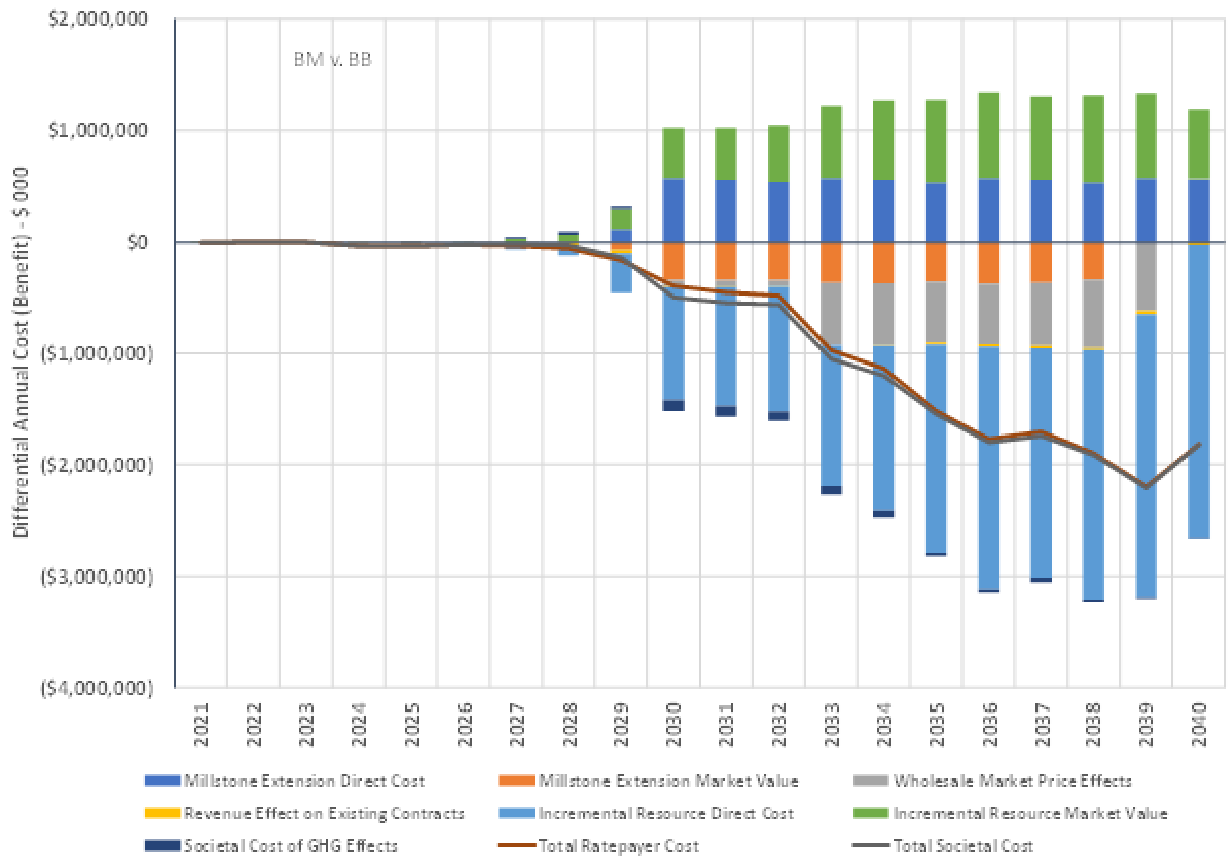
	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	7	0	0
2030	0	348	0	0
2031	0	687	0	0
2032	170	1,024	0	0
2033	170	1,360	0	0
2034	170	1,693	0	0
2035	170	2,025	238	0
2036	170	2,315	238	129
2037	170	2,304	238	392
2038	207	2,292	238	917
2039	524	2,281	238	1,180
2040	865	2,269	238	1,446

Figure 1.15 shows the costs projected by the model under the Base Load Millstone Extension scenario compared to the Base Load Balanced Blend scenario (not the Base Load Reference scenario). Cost differentials against the Base Load Reference scenario can be found in Appendix A3.[43]

In 2029, the Base Load Millstone Extension scenario becomes cheaper, as modeled, than the Base Load Balanced Blend scenario "Incremental Resource Direct Cost"), or the avoided cost of deploying more new, renewable zero carbon resources than the Base Load Balanced Blend scenario because of Millstone's continued operation.

[43] The assumed cost of the Millstone PPA extension is the current contract price, $49.99/MWh, adjusted for inflation at 2 percent each year.

Figure 1.15: Differential Annual Costs – Base Load Millstone Extension Scenario vs. Base Load Balanced Blend Scenario



Compared to the Base Load Balanced Blend scenario, the net present value to ratepayers of the Millstone Extension scenario, calculated over the 20-year modeling period at a nominal discount rate of seven percent, is a savings of $5.0 billion. Compared to the business-as-usual Base Load Reference scenario, which also assumes Millstone retires in 2029, the net present value to ratepayers of extending Millstone's contract is a savings of $1.25 billion. Again, these benefits are primarily produced by the avoided incremental resource additions needed over the course of the study period.

Electrification Load Millstone Extension (EM) Scenario

Key Findings: Electrification Load Millstone Extension

- Present Value Total Societal Cost: -$1.5B
- Present Value Total Ratepayer Cost: -$0.63B
- 2040 zero carbon goal will be met, as are interim annual targets
- 6.8 GW Connecticut clean energy procurements by 2040
- 8.6 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~26% by 2040 due to transition from high variable cost resources to high fixed cost resources

Similar trends occur under the Electrification Load Millstone Extension scenario. Regional clean energy additions are minimized as compared to the Electrification Load Balanced Blend scenario, and, in fact, align more closely with additions expected under the Base Load Balanced Blend scenario. The Electrification Load Millstone Extension scenario also decreases the total operating reserve amounts compared with the Electrification Load Balanced Blend scenario as fewer VER resources are needed to meet the carbon constraints, which also means greater stability in energy output levels.

The Electrification Load Millstone Extension scenario has the highest level of retirements of the Electrification Load Zero Carbon Policy scenarios (see Appendix A3). This is because even under an increased regional energy load, the consistent availability of reliable nuclear energy reduces the overall amount of resource additions needed to meet capacity requirements, and reduces the amount of "fast-ramping"(usually fossil fuel-powered) resources needed to be retained for peak demand periods in order to balance the clean energy resource additions. In other words, as previously shown by Figures 1.10 and 1.11, the Zero Carbon Policy scenarios must meet a higher absolute operating reserve requirement in order to preserve reliability under the Electrification Load than the Base Load, coincident with the increased need for renewable VERs to meet the load and Regional Emissions Target. But, if Millstone continues to operate, the need for a higher absolute operating reserve requirement is avoided, and more fossil units can retire. Whereas in the Base Load scenarios, lower load means lower absolute reserve requirements and therefore greater retirement levels, in the Electrification Load scenarios, higher load means higher reserve requirement and therefore lower retirement levels across the scenarios.

The Electrification Load Millstone Extension scenario delays incremental clean energy additions by about four years for Connecticut as compared with the Electrification Load Balanced Blend scenario, as demonstrated by Figure 1.16. The year 2029 shows the beginning of the modeled Millstone extension, and a very small resource addition amount. Millstone's extension is fully captured by the Millstone Extension bar for the remainder of the study period, which minimizes the amount of additions needed to meet the 100% Zero Carbon Target as compared with the Electrification Load Balanced Blend scenario. Table 1.5 shows the cumulative resources allocated to Connecticut by year.

Figure 1.16: Connecticut Incremental Resource Allocation, Electrification Load Millstone Extension Scenario

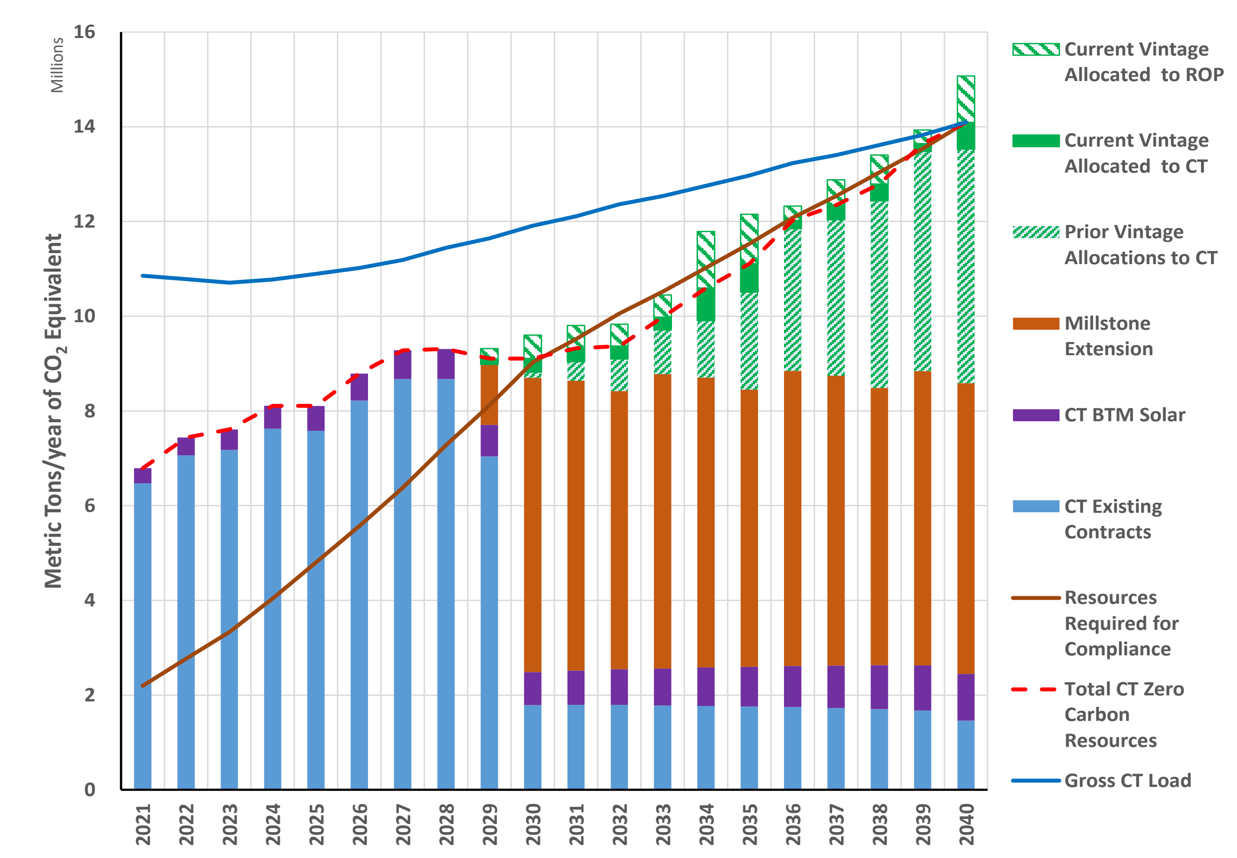


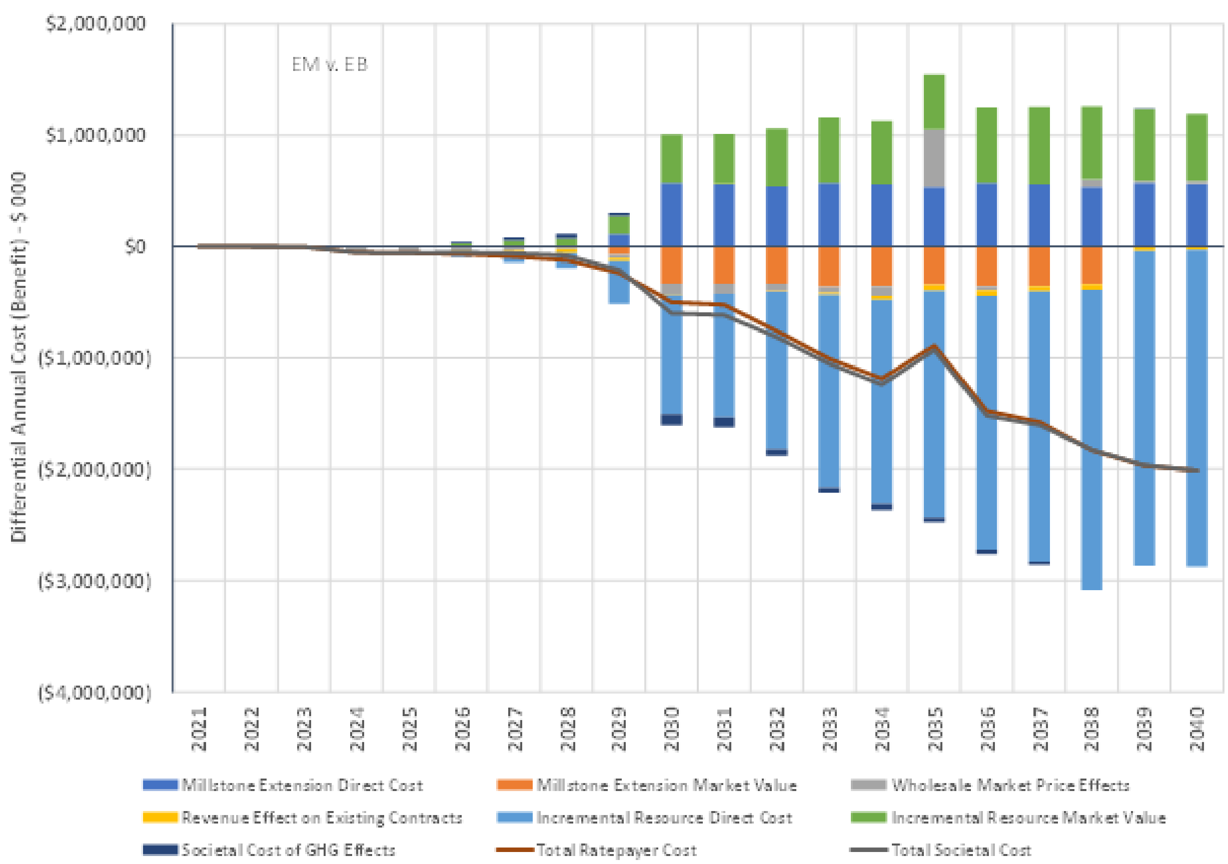
Table 1.5: Cumulative Incremental Resource Capacity, Electrification Load Millstone Extension Scenario

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	161	0	0
2030	0	526	0	0
2031	0	888	0	0
2032	183	1,249	0	0
2033	183	1,608	0	0

2034	183	1,965	256	139
2035	183	2,321	438	420
2036	183	2,309	438	841
2037	240	2,474	438	1,115
2038	490	2,462	438	1,679
2039	855	2,449	438	2,116
2040	1,220	2,437	438	2,713

The Electrification Load Millstone Extension scenario annual benefits, as shown in Figure 1.17, are similar to those under the Base Load Millstone Extension scenario, with annual net benefits generally increasing after 2028. Under this scenario, the model projects ratepayers will still see a net benefit with a present value savings of $5.0 billion compared to the Electrification Load Balanced Blend scenario, and a net benefit of $625.0 million compared to the Electrification Load Reference scenario. This amount increases to a net benefit of approximately $1.5 billion when the societal avoided costs of GHG effects are accounted for.

Figure 1.17: Differential Annual Costs – Electrification Load Millstone Extension Scenario vs. Electrification Load Balanced Blend Scenario



BTM Solar PV Emphasis Scenarios

The BTM Solar PV Emphasis ("BTM Emphasis") scenarios select the lowest cost portfolio of resources needed to meet the region's aspirational energy policy goals, including Connecticut's 100% Zero Carbon Target, assuming that the level of BTM solar PV deployment effectively doubles over the Reference scenario. This increase equates to an additional 190 MWs of BTM solar PV being deployed in the region each year on average for both load cases. The scenarios also assume that 55 MWs of those additional 190 MWs on average are deployed in Connecticut each year.[44] Because BTM solar PV is a load modifier, this reduces the gross load (net of energy efficiency) that must be met by other energy resources, but also changes the hourly shape of net load as solar PV can only produce during the day. Therefore, the model's selection of incremental resources is different from the Balanced Blend scenarios.

Base Load BTM Solar PV Emphasis (BS) Scenario

Under the Base Load, the BTM Emphasis scenario results in the largest quantity of cumulative regional additions at 32 GW, and the most retirements at 10.8 GW. This quantity is primarily increased by the assumed greater deployment of BTM solar PV resources across the region, which offsets some of the resources expected for selection under the Balanced Blend, such as OSW. The key variable is that unlike the Balanced Blend, where the model selects the resources based on least-cost deployment, this scenario forces an amount of capacity that relies on increased individual (i.e. ratepayer) participation in solar PV programs across the region into the model. Then, the model has to select enough resources to meet capacity and reliability needs at all hours while still meeting the GHG emissions constraint.

Key Findings: Base Load BTM Solar PV Emphasis

- Present Value Total Societal Cost: $4.01 B
- Present Value Total Ratepayer Cost: $4.60 B
- 2040 zero carbon goal will be met, some interim years fall short
- 8.5 GW Connecticut clean energy procurements by 2040
- 10.7 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~22% by 2040 due to transition from high variable cost resources to high fixed cost resources

Connecticut will still need to procure 8.5 GW of clean energy resources by 2040 in this scenario, approximately the same as in the Base Load Balanced Blend. Figure 1.18 shows the cumulative resources allocated to Connecticut by year in order to meet the necessary emissions reduction targets to achieve the 100% Zero Carbon Target. Like in the Base Load Balanced Blend scenario, under the BTM PV Emphasis scenario, Connecticut exceeds the necessary annual reductions until the retirement of Millstone in 2029, and then needs to procure enough resources to offset the loss of that resource and meet growing demand. The inclusion of additional BTM solar helps to fulfill a small portion of that need. Table 1.6 shows the cumulative resources allocated to Connecticut by year.

[44] See Appendix A1 for further information about BTM solar PV deployment assumptions used in the modeling.

Figure 1.18: Determination of Connecticut Incremental Resource Allocation, Base Load BTM Solar PV Emphasis Scenario

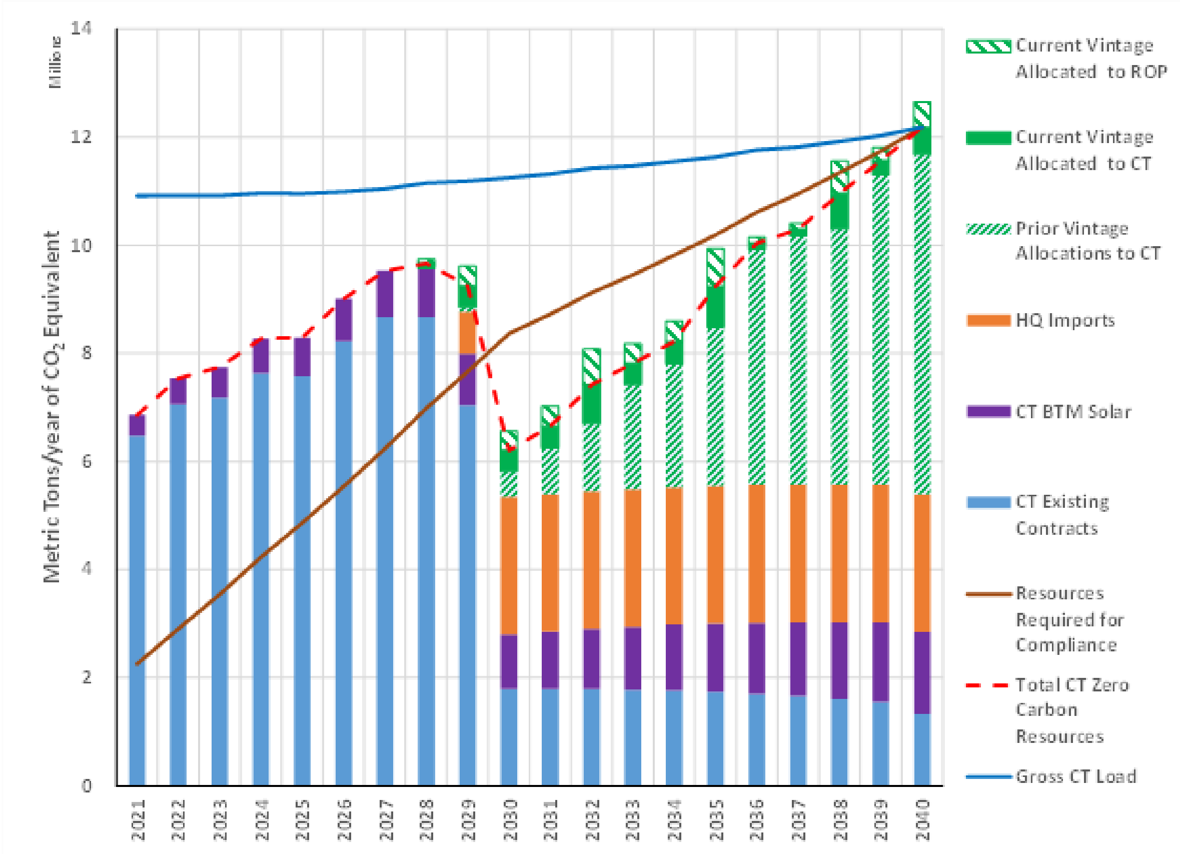


Table 1.6: Cumulative Incremental Resource Capacity, Base Load BTM Solar PV Emphasis Scenario

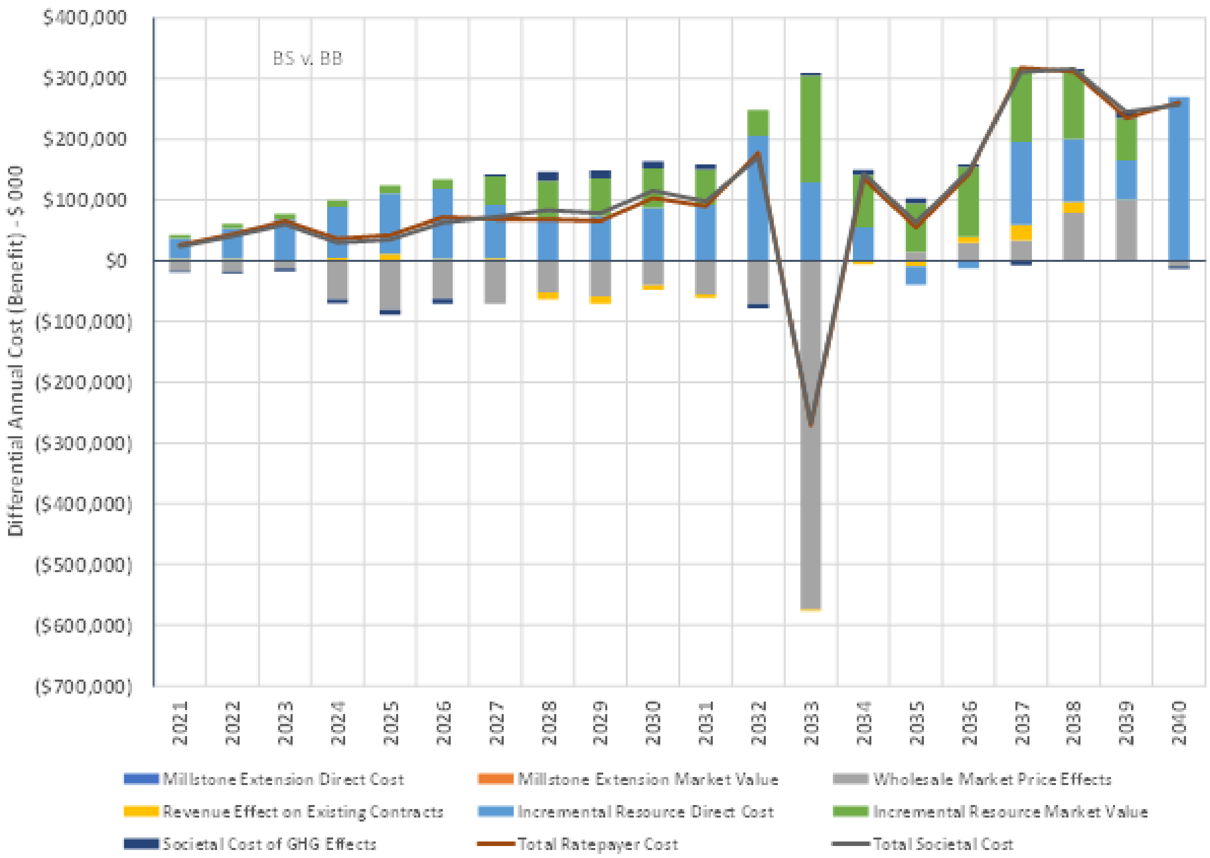
	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	105	0	0
2029	0	624	0	0
2030	0	1,140	0	0
2031	0	1,653	0	0
2032	260	2,163	363	0
2033	260	2,672	363	0

2034	260	2,870	363	197
2035	260	3,188	363	794
2036	308	3,348	363	1,391
2037	308	3,498	363	1,588
2038	760	3,481	623	1,984
2039	760	3,463	623	2,588
2040	1,279	3,446	623	3,221

The Base Load BTM Solar Emphasis scenario annual net costs are shown in Figure 1.19. Generally, the cost of achieving zero carbon by 2040 results in a net cost both with and without societal benefits. Under this scenario, ratepayers will still see a projected net present value cost of an additional $846 million over the cost of the Base Load Balanced Blend, for a total cost of $4.6 billion compared to the Base Load Reference scenario. This amount is slightly offset by the inclusion of an estimated $609 million in societal avoided costs of GHG, bringing the total societal cost to just over $4 billion. The large "Wholesale Market Price Benefits" value in 2033 was driven by capacity prices when battery resources become the marginal resource a year earlier relative to the Base Load Balanced Blend scenario, which is the baseline in the graph below.[45]

[45] Battery resources do become the marginal resource in every scenario, just at different times. For most of the study period, the marginal resource identified was a conventional fossil resource. In the early 2030's, batteries are needed to meet resource adequacy targets. The cost of battery additions therefore set the capacity price. For more information on the capacity price calculations, see Appendix A3.

Figure 1.19: Differential Annual Costs – Base Load BTM Solar PV Emphasis Scenario v. Base Load Balanced Blend Scenario



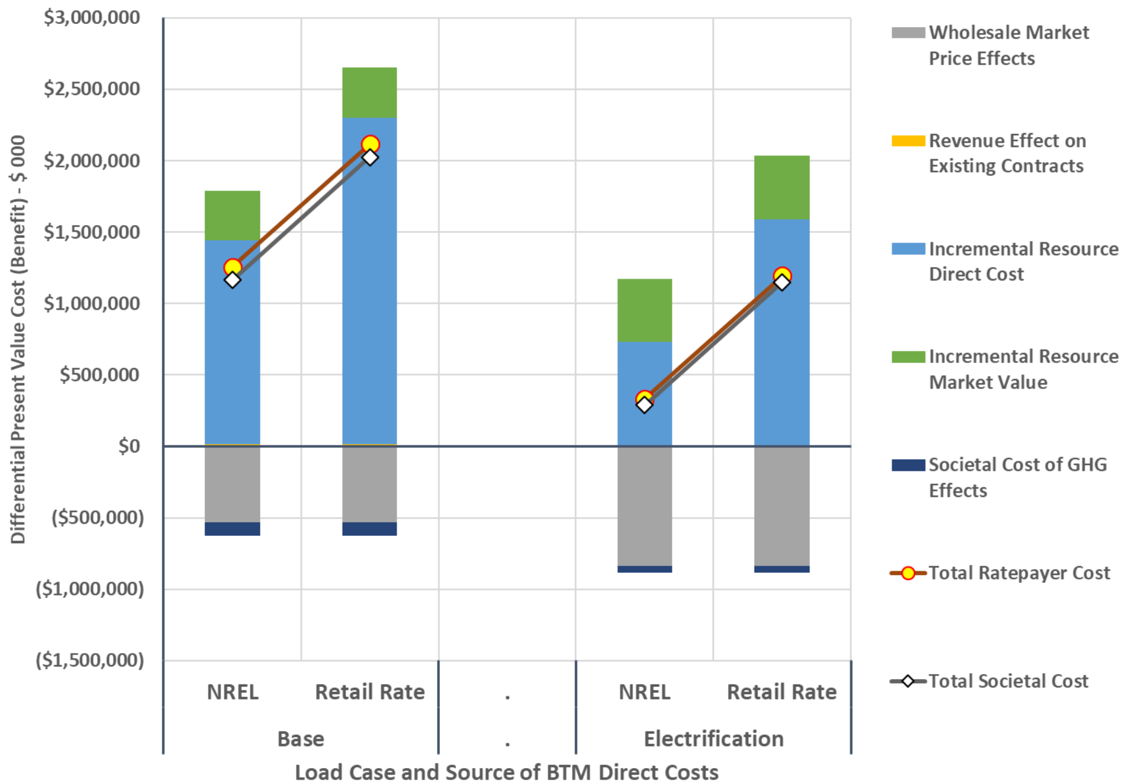
In addition, DEEP analyzed the cost differential between a BTM solar program that compensates based on projected cost of deploying the unit compared to a program that compensates based on the residential retail rate, effectively comparing the cost of a potential successor tariff structure with the cost of existing net metering.[46] The Department notes this comparison is for illustrative purposes and should not necessarily be used to establish a tariff rate pursuant to Section 16-244z of the Connecticut General Statutes.

In addition, as noted in the Introduction, this IRP is not a full cost-benefit analysis of policies supporting different zero carbon resources; rather, it analyzes the comparative resource price and emissions impacts on the regional electric supply from pathways to meet the 100% Zero Carbon Target. This IRP also assesses the price and emissions impacts based on current policy structures and those impacts can change in future IRPs as dynamic pricing structures are more widely adopted and the capabilities of technologies like BTM solar paired with energy storage on a modernized grid offers new value. Figure

[46] The residential retail rate used in this sensitivity analysis is Eversource's Rate R, effective January 1, 2020, inclusive of the average generation rate from July 1, 2020 and January 1, 2020. This rate is escalated 2 percent. This rate is used as an illustrative example. The cost of deploying the unit was based on NREL studies on the cost of deploying solar, as discussed in more detail in Appendix A1.

1.20 further demonstrates how deploying additional BTM solar units at different compensation levels affects the present value of net costs by comparing the costs based on National Renewable Energy Laboratory (NREL) cost data versus the Connecticut residential rate under each load level.[47] The baselines for comparison are the Balanced Blend scenarios.

Figure 1.20: Present Value Cost of BTM Solar Compensated at the Cost System Deployment Compared to the Residential Retail Rate



Because Figure 1.20 compares the present value electric system costs and benefits of the same amount of BTM solar, based upon two different compensation structures, the relative comparison of one structure against another will remain the same, regardless of additional cost or benefit categories added. It is important to note that these compensation structures were applied for illustrative purposes and that these cost assumptions should not be used as the tariff rate to be established by PURA in Docket No. 20-07-01 for the residential solar PV successor tariff.

Figure 1.20 serves as an illustration of the impact of different levels of compensation with an estimated present value based on the cost assumptions described above. The NREL cost data indicates that residential solar PV is being successfully deployed at average prices of approximately $0.105/kWh cross the US, while here in CT the price paid for solar PV is much higher because it is tied to the retail rate (under the current net metering regime).[48] The NREL figures suggest Connecticut could still see successful deployment at a lower price than the retail rate. A related insight is that the state could

[47] As indicated in Appendix A1, BTM solar costs were estimated using NREL's 2019 ATB database.

[48] National Renewable Energy Laboratory. 2020 Annual Technology Baseline: Residential PV Systems. https://atb.nrel.gov/electricity/2020/index.php?t=sr

deploy a higher of quantity BTM solar PV to reach the 100% Zero Carbon Target at the same the ratepayer cost, if the price is set optimally. PURA is currently reviewing what constitutes "average cost of installing the generation project and a reasonable rate of return that is just, reasonable and adequate" as directed by statute to establish the ultimate residential tariff rate.[49, 50]

Electrification Load BTM Solar PV Emphasis (ES) Scenario

The Electrification Load BTM Solar PV Emphasis scenario projects similar outcomes to the Base Load BTM PV Emphasis scenario. Again, compared with the other scenarios under the Electrification Load, this scenario will result in the largest amount of cumulative regional additions (inclusive of BTM resources) by 2040, primarily driven by the amount of increased BTM PV assumed at the outset. Connecticut will need to procure 10.6 GW of grid scale resources, approximately 40 percent of the regional amount.

Key Findings: Electrification Load BTM Solar PV Emphasis

- Present Value Total Societal Cost: $4.2 B
- Present Value Total Ratepayer Cost: $4.9 B
- 2040 zero carbon goal will be met, though some interim years fall short
- 10.6 GW Connecticut clean energy procurements by 2040
- 7.5 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~26% by 2040 due to transition from high variable cost resources to high fixed cost resources

Retirement levels are similar to the other scenarios that include Millstone's retirement. Therefore, under the Electrification Load, about 30 percent fewer MW of fossil resources retire over the modeling horizon in order to maintain reliability.

Figure 1.21 shows the cumulative resources allocated to Connecticut by year in order to meet the necessary emissions reduction targets to achieve the 100% Zero Carbon Target under this scenario. The trajectory towards the 2040 goal in the Electrification Load is like that of the Base Load for the BTM Solar PV Emphasis scenario. Table 1.7 shows how the various incremental resources are allocated to Connecticut by year.

[49] Conn. Gen. Stat. Sec. 16-244z(b).
[50] The modeling prepared for this IRP was not prepared for the purposes of PURA Docket No. 20-07-01.

Figure 1.21: Determination of Connecticut Incremental Resource Allocation, Electrification Load BTM Solar PV Emphasis Scenario

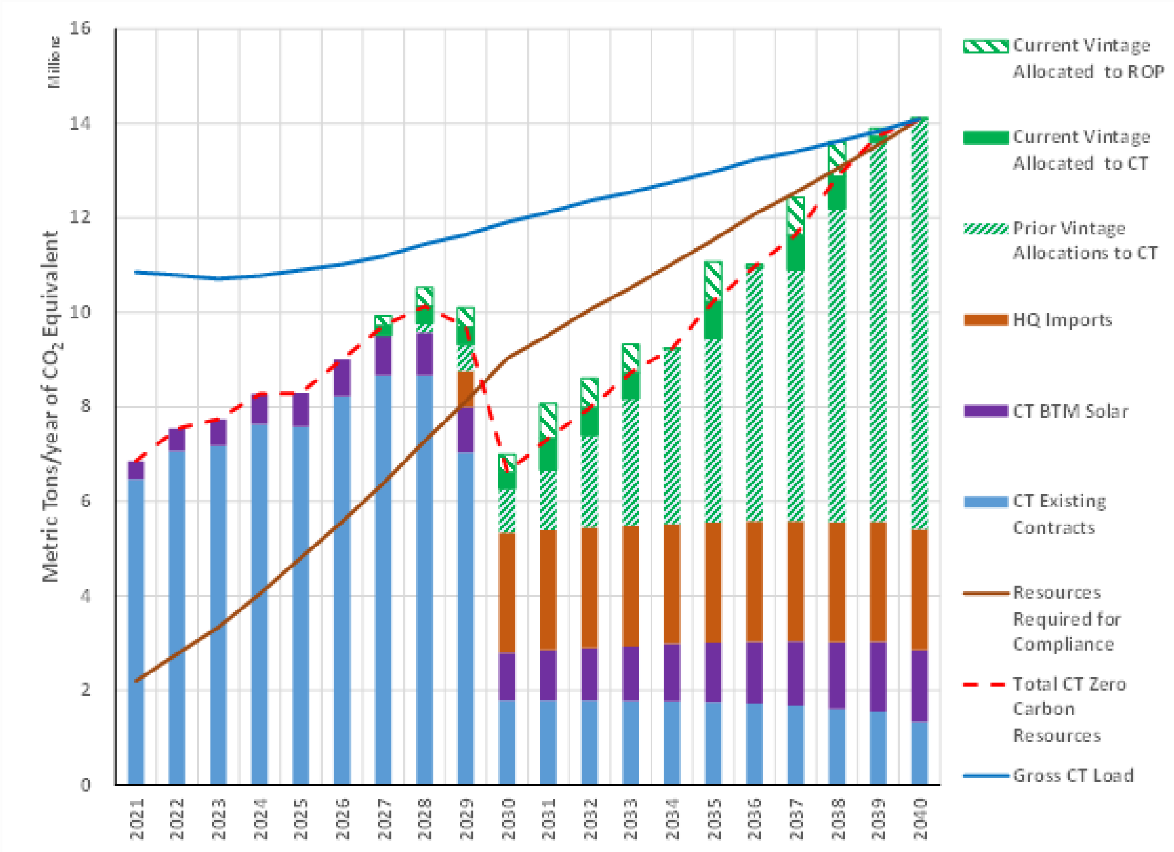


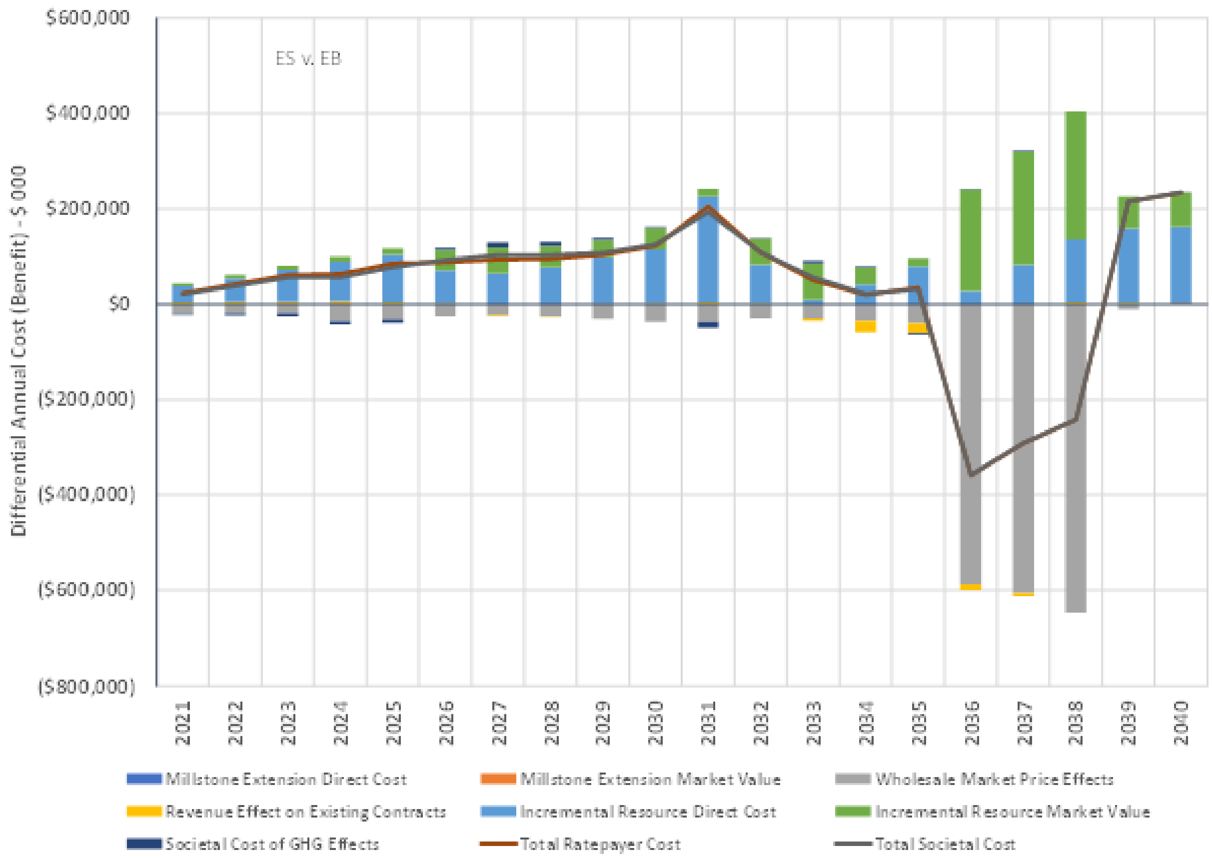
Table 1.7: Cumulative Incremental Resource Capacity, Electrification Load BTM Solar PV Emphasis Scenario

Calendar Year	Cumulative Incremental Resource Allocation			
	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	265	0	0
2028	0	743	0	0
2029	0	1,220	0	0
2030	240	1,694	0	0
2031	240	2,165	336	0
2032	480	2,635	336	182
2033	480	3,046	336	547

2034	960	3,090	336	911
2035	960	3,139	336	1,653
2036	960	3,183	336	2,212
2037	1,080	3,188	336	2,793
2038	1,560	3,172	336	3,958
2039	1,560	3,156	576	4,742
2040	1,560	3,164	576	5,326

The Electrification Load BTM Solar PV Emphasis scenario annual net costs are shown in Figure 1.22. As with the Base Load scenario, the cost of achieving zero carbon over 2040 with additional BTM PV produces a net cost, even with societal benefits factored in. Under this scenario, the model projects that ratepayers will still see a net present value cost of an additional $529 million over the cost of the Base Load Balanced Blend scenario, for a projected total cost of $4.9 billion compared to the Electrification Load Reference scenario. When avoided societal costs of GHGs are accounted for, the costs are offset by an estimated $704 million in societal avoided costs of GHG. Costs in most years are dominated by the “Incremental Resource Costs” (light blue bars), which include the gross costs of the added BTM resources in Connecticut. These costs are incurred from 2021 on, but they are reversed from 2032 through 2034. The “Wholesale Market Price Effects” (gray) bars represent energy and capacity effects on a cost-to-load basis. Cost-to-load benefits increase significantly from 2036 to 2038 due to capacity price difference, like the Base Load scenarios.

Figure 1.22: Differential Annual Costs –Electrification Load BTM Solar PV Emphasis Scenario v. Electrification Load Balanced Blend Scenario



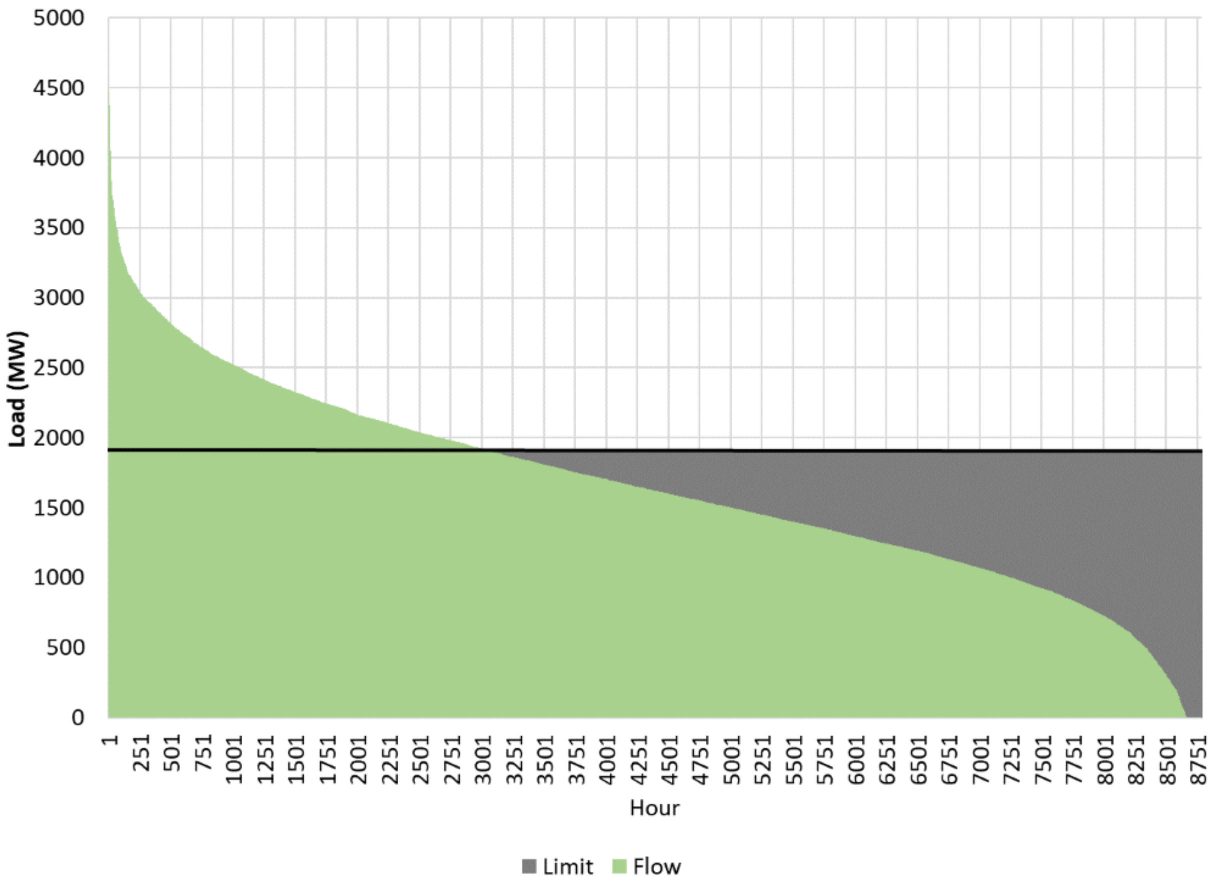
No Transmission Constraint Scenarios

Transmission lines and infrastructure are limited by factors like thermal and voltage capacity. Where line capacity is limited by transmission constraints, grid congestion produces inefficiencies and losses. The No Transmission Constraints scenarios ("Transmission scenarios") are a sensitivity analysis that applies relaxed transmission constraints to the resources selected in both Balanced Blend scenarios. This analysis is used to determine how relieving lines that would otherwise experience energy flows above the line limits affects the resource buildout while still meeting the region's aspirational energy policy goals, including Connecticut's 100% Zero Carbon Target. In other words, the goal of these scenarios is to test what would happen to the modeled resource portfolio if electricity was able to flow freely throughout New England, without being constrained by points on the grid by limits on the transmission lines that prevent the free movement of supply to load.

Transmission congestion points were identified by evaluating flows for all hours in 2040 to determine which interfaces would have flows above the line limits absent constraints. For example, Figure 1.23 below shows the hourly 2040 Southern Maine to New Hampshire flows from the Base Load Transmission scenario in green ("Line/Transmission Flow") compared to the limit in grey ("Line/Transmission Limit"), also noted with a black line. In all other Base Load scenarios, the hourly flow limit on this interface is 1,900 MW, as indicated by the black line. Relaxing this constraint resulted in 3,078 hours in which the flow on the interface exceeded the known 1,900 MW limit. Increasing the limit on the interface by 1,000

MW reduces the number of times the limit would have been exceeded to just 13 percent of occurrences. Further analysis on other interface flows can be found in Appendix A3.

Figure 1.23: Southern Maine to New Hampshire Interface Flows, 2040 All Hours



The transmission system's ability to support increasing amounts of clean energy resources is vital to meeting climate goals in the coming decades. While this scenario does not account for the costs of the upgrades required to achieve an unconstrained system, it provides information that will allow for more strategic planning and investment.

Base Load No Transmission Constraint (BT) Scenario

The modeling results in the Base Load No Transmission Constraint scenario for regional additions and retirements are nearly identical to the results in the Base Load Balanced Blend scenario. However, the BT scenario results in less curtailment of some resources, and the reduced, or deferred, need for various incremental resources in the later years of the study period. Connecticut therefore will need to have procured approximately the same number of MWs from clean energy resources as it would in the Base Load Balanced Blend scenario by 2040, but all energy is more efficiently allocated across the region in the BT scenario, and less clean energy is constrained or curtailed.

Key Findings: Base Load No Transmission Constraint

- Present Value Total Societal Cost: $2.8 B
- Present Value Total Ratepayer Cost: $3.3 B
- 2040 zero carbon goal will be met, some interim years fall short
- 8.5 GW Connecticut clean energy procurements by 2040
- 10.7 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~25% by 2040 due to transition from high variable cost resources to high fixed cost resources

Figure 1.24 demonstrates Connecticut's trajectory towards the 2040 goal under this scenario. It is very similar to that of the Base Load Balanced Blend scenario. Table 1.8 displays the annual resource allocations to Connecticut.

Figure 1.24: Determination of Connecticut Incremental Resource Allocation, Base Load No Transmission Constraint Scenario

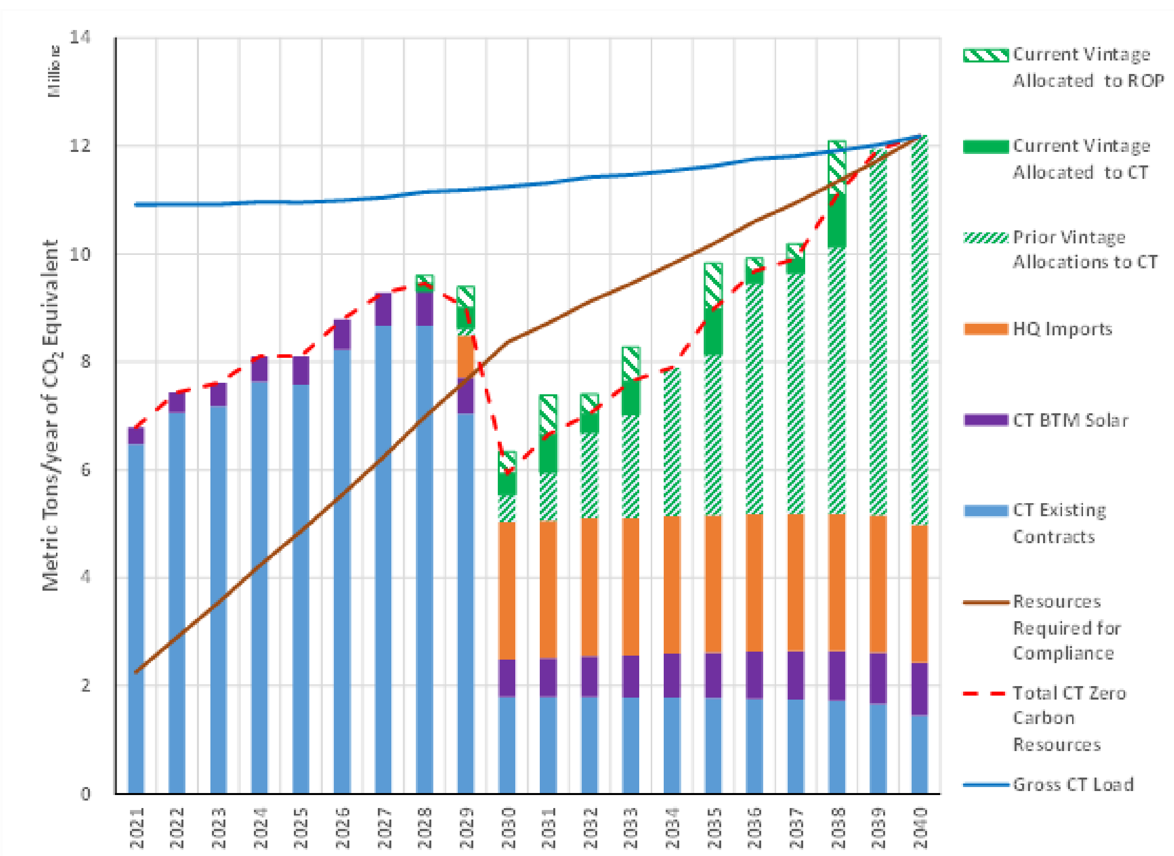


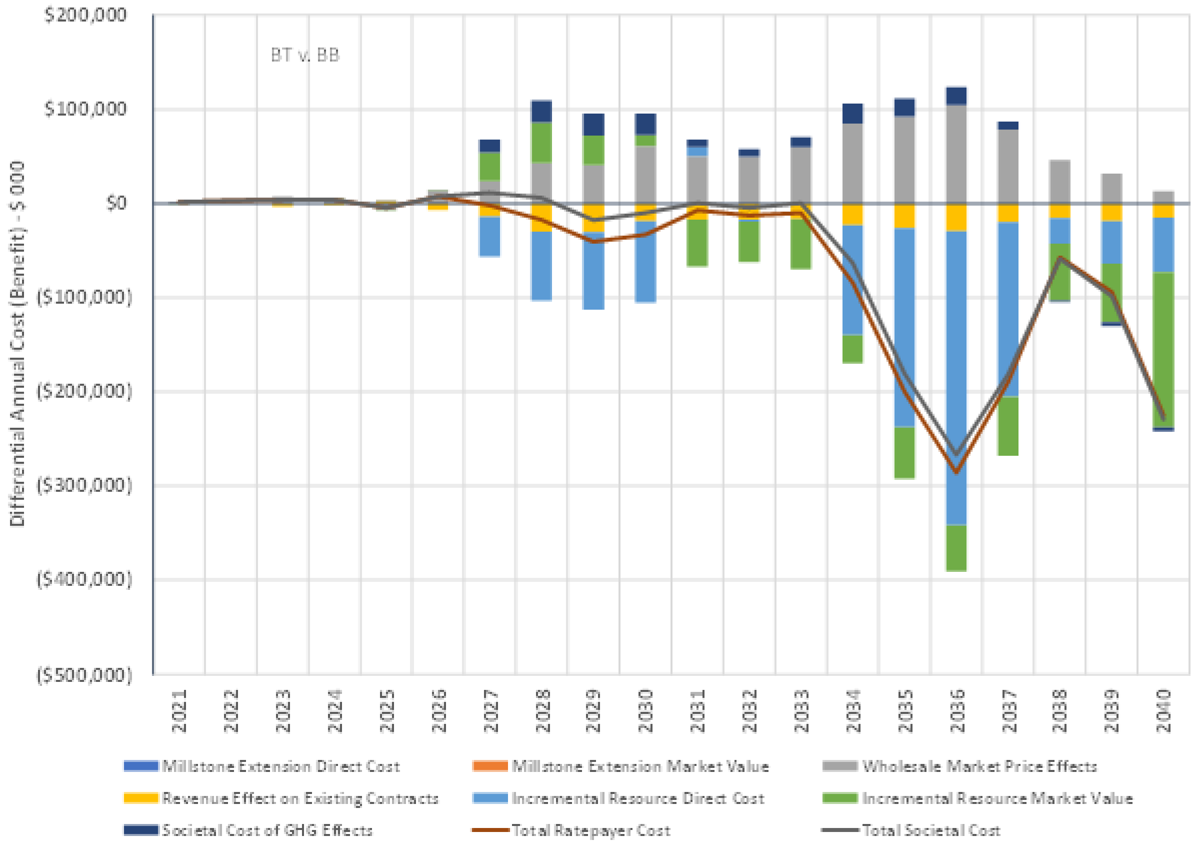
Table 1.8: Vintage Incremental Resource Allocation, Base Load No Transmission Constraint Scenario

	Cumulative Incremental Resource Allocation			
Calendar Year	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	192	0	0
2029	0	682	0	0
2030	0	1,170	0	0
2031	163	1,655	344	0
2032	408	2,137	344	0
2033	408	2,617	344	186
2034	408	2,604	344	373
2035	408	3,038	344	933
2036	408	3,320	344	1,308
2037	408	3,304	344	1,505
2038	862	3,287	344	2,482
2039	862	3,271	344	3,262
2040	1,246	3,255	344	3,653

The key difference between the Base Load Balanced Blend scenario and the Base Load No Transmission Constraint scenario is the overall cost. Throughout the first half of the study period, and some of the second, costs remain about the same as the Base Load Balanced Blend scenario. However, in 2033, ratepayers will begin to see a financial net benefit. By alleviating constraints in the existing transmission system, the model projects that ratepayers will see a cumulative financial benefit of $400 million in present value relative to the Base Load Balanced Blend scenario. This is driven primarily by about $500 million in incremental resource direct cost savings because, without transmission congestion, more expensive resources are displaced from the portfolio. Wholesale market price effects are projected amount to $300 million present value, reflecting the lost wholesale price benefits associated with the various technologies in the Base Load Balanced Blend scenario.

As previously stated, this simplified analysis does not include the costs of transmission upgrades, which are difficult to project. Thus, while the net benefits are not reflective of the total cost or benefit to ratepayers, this analysis illustrates the potential value of alleviating transmission constraints and the comparative value of addressing infrastructure upgrades as a strategy for preparing for the 100% Zero Carbon Target.

Figure 1.25: Differential Annual Cost – Base Load No Transmission Constraint Scenario v. Base Load Balanced Blend Scenario



Electrification Load No Transmission Constraint (ET) Scenario

As with the BT scenario, the Electrification Load No Transmission Constraint scenario's additions and retirements are very closely aligned with those in the Electrification Base Load Balanced Blend scenario. However, the No Transmission Constraint scenario avoids the need for nearly a gigawatt of clean energy additions. As found in the BT scenario, alleviating points of congestion helps allow energy to be more efficiently flow across the region to the places that need it.

Likewise, the analysis indicates that Connecticut will need to procure 10.5 GW of grid scale clean energy resources by 2040 under this scenario, about 430 MW less than under the Electrification Load Balanced Blend scenario.

Key Findings: Electrification Load No Transmission Constraint

- Present Value Total Societal Cost: $2.99 B
- Present Value Total Ratepayer Cost: $3.6 B
- 2040 zero carbon goal will be met, though some interim years fall short
- 10.5 GW Connecticut clean energy procurements by 2040
- 7 GW regional fossil fuel retirements by 2040
- CT wholesale energy price decreases ~35% by 2040 due to transition from high variable cost resources to high fixed cost resources

Figure 1.26 graphs the trajectory towards the 100% Zero Carbon Target for Connecticut's electric supply under this scenario. As with the other scenarios, the Electrification Load No Transmission Constraint scenario meets the 100% Zero Carbon Target in 2040 but falls short in some interim years after Millstone's projected retirement in 2029. However, it should be noted that this scenario is able to meet the target with fewer incremental resource additions. Table 1.9 displays the annual resource allocations to Connecticut under this scenario.

Figure 1.26: Determination of Connecticut Incremental Resource Allocation, Electrification Load No Transmission Constraint Scenario

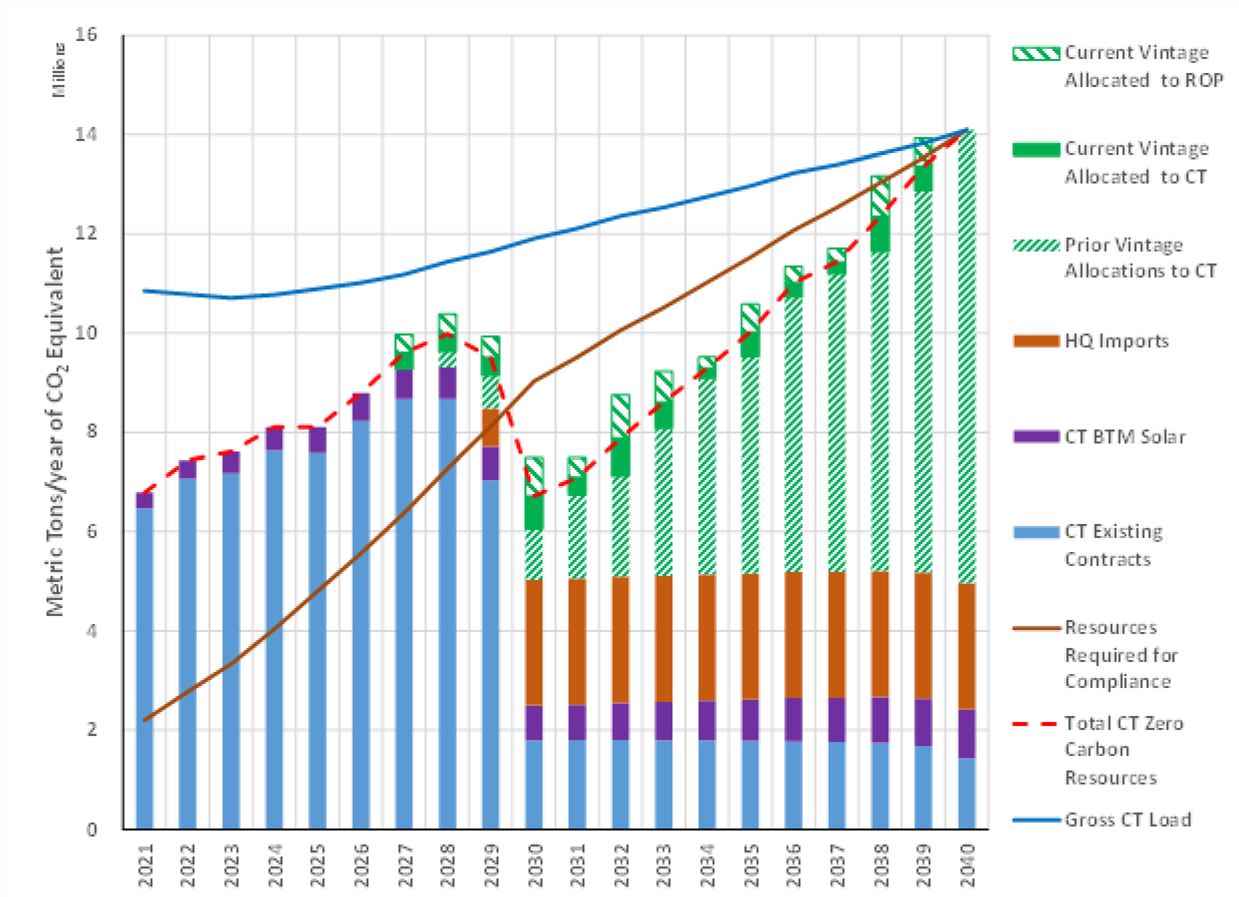


Table 1.9: Cumulative Incremental Resource Capacity, Electrification Load No Transmission Constraint Scenario

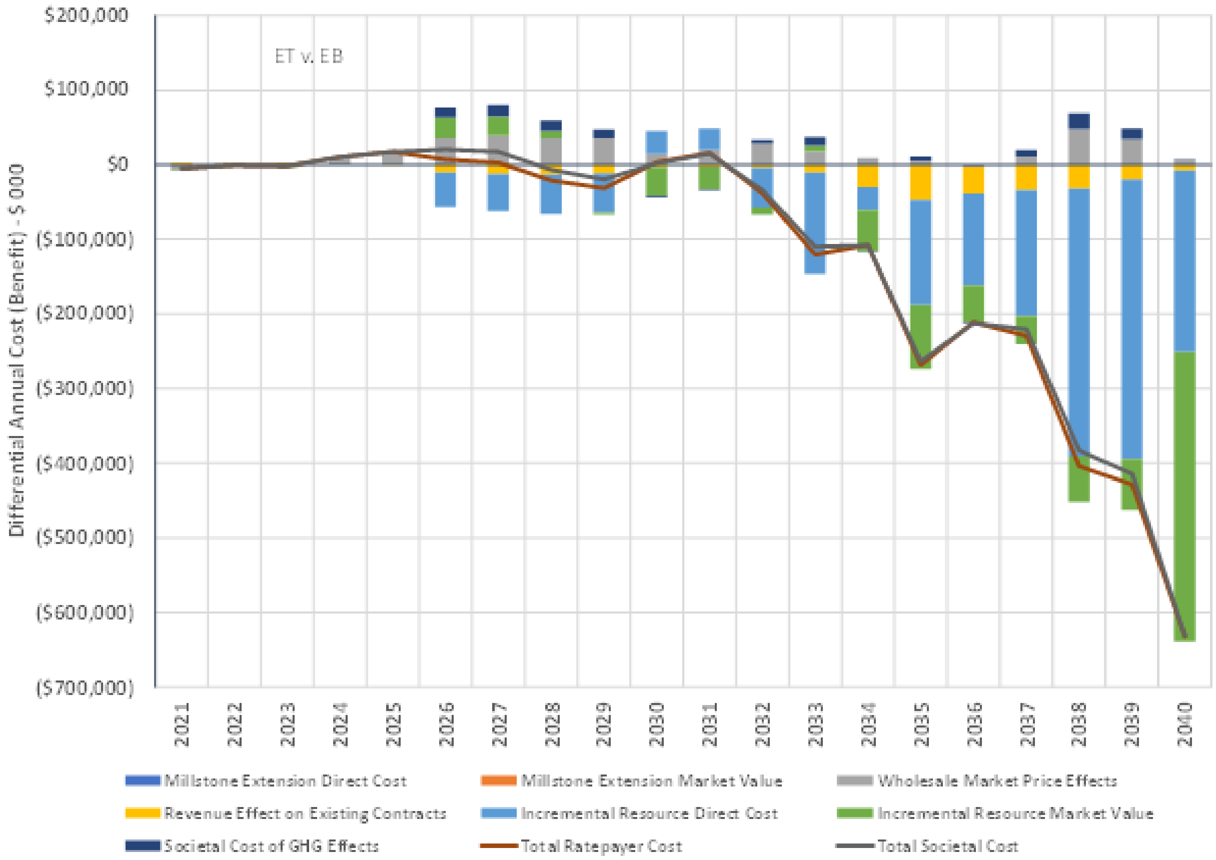
Calendar Year	Cumulative Incremental Resource Allocation			
	CT Storage (MW)	CT Solar (MW)	CT LBW (MW)	CT OSW (MW)
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0

2027	0	432	0	0
2028	0	895	0	0
2029	0	1,355	0	0
2030	232	1,813	325	0
2031	232	2,269	325	0
2032	465	2,722	558	177
2033	465	3,095	558	535
2034	930	3,079	558	1,070
2035	930	3,064	558	1,615
2036	930	3,125	558	2,332
2037	1,055	3,109	558	2,692
2038	1,519	3,093	558	3,452
2039	1,519	3,078	558	4,397
2040	1,519	3,063	558	5,343

Under the Electrification Load, the No Transmission Constraint scenario shows small changes in net cost compared to the Balanced Blend scenario through 2030, followed by increasing net benefits in the later years, shown in Figure 1.27. This is driven primarily by incremental resource direct cost reductions because, without transmission constraints, more expensive resources are displaced from the portfolio of selected resources. Ratepayers are projected to see an overall net benefit in this scenario of $699 million present value as compared to the Electrification Load Balanced Blend scenario. When avoided societal costs of GHG emissions are accounted for, the overall net benefit increases to $752 million.

As referenced in the Base Load No Transmission Constraint scenario section, this analysis does not account for the costs of transmission upgrades, but it does highlight the value of these upgrades. Particularly in an electrified future where load has increased to support deployment of EVs and air source heat pumps (ASHPs), and the amount of variable energy resource capacity is higher than ever, it is necessary to weigh the options to meeting a zero carbon electric supply. Transmission upgrades may be a more cost-effective way to support these strategies.

Figure 1.27: Differential Annual Costs – Electrification Load No Transmission Constraint Scenario v. Electrification Load Balanced Blend Scenario



Strategies to Achieve Objective 1

The modeling results described above provide for several key insights that inform this IRP's recommendations for continuing the decarbonization of the electric sector in a manner that is both reliable and affordable for ratepayers. Modeling is, of course, not a perfect predictive tool for what will actually happen, and none of the scenarios modeled are an expression of a preferred policy or procurement strategy. Rather, the scenarios indicate key contingencies that can have a significant effect on the pace of emission reductions, the cost of achieving those reductions, and the quantities of different types of resources that could be utilized to meet the 2040 goal under various circumstances.

Part II of this IRP lists several strategies in furtherance of Objective 1, Decarbonizing the Electricity Sector. Many of these strategies also support other Objectives that will be discussed further below. Based on the modeling above, there are several contingencies to consider including:

- <u>The Millstone nuclear facility continues to play an outsized role in Connecticut's— and the region's— decarbonization pathways.</u> As noted above, the modeled Millstone Extension scenario achieves the 100% Zero Carbon Target at a lower cost ($5.0 billion lower net present value to ratepayers) than the Base Load Balanced Blend scenario. The Millstone Extension scenario as modeled results in greater fossil fuel retirements and produces net savings for ratepayers ($1.25 billion in net present value) as compared to the business-as-usual Base Load Reference scenario, because it avoids the need for the region to procure comparatively larger quantities of new zero carbon resources to replace the Millstone facility.
- <u>The timing and quantity of procurement of new renewable resources will depend on a variety of factors.</u> Based on the modeling above, the IRP does not identify an immediate need to procure new renewable generation in 2021 or 2022. Beyond that, a variety of factors could influence a procurement timeline, including whether market conditions and rules change in the near future (Strategy 2), the rate of electrification of the building and transportation sector, and whether modeled or contracted resources are able to achieve commercial operation. The scenarios require substantial additional quantities of hydro and grid-scale renewables like solar because they can be more economic, but whether they materialize depends on their ability to meet siting and other challenges. Moreover, already-contracted resources can also run into challenges. These challenges can increase costs and slow or even stop development. While acknowledging the need to monitor these and other conditions, this IRP relies on the modeled resource capacity needs to develop a schedule of procurements, which is particularly important for offshore wind (Strategy 5) since it takes several years to plan.
- <u>BTM resources are currently more expensive than grid scale resources, but that price gap could be narrowed</u> if the tariffs for BTM resources are updated to reflect lower technology costs, and siting availability for grid scale resources become more limited to protect natural resources and land use and to reduce environmental quality impacts (Strategy 10). At that point, consideration could be given to scaling BTM specifically to meet decarbonization needs, and associated cost impacts.
- <u>The deployment of different quantities of variable renewable resources like wind and solar will also require deployment of "balancing" resources or reserves, to ensure grid reliability without compromising emission reduction benefits</u>. Connecticut must recognize and value technologies that will help balance and optimize the variable energy capacity needed to meet Objective 1, while also avoiding emissions. This includes continuing to invest in load reduction measures such as cost-

effective energy efficiency and expanding demand response through the C&LM Plan (Strategy 12) and supporting the development of storage (Strategy 13).

- Investing in transmission to remove constraints may be a more cost-effective way to reach the 100% Zero Carbon Target. Transmission upgrades can reduce spillage of energy from clean energy resources, and generate up to $400 million in ratepayer benefits, relative to the Base Load Balanced Blend. However, these benefits need to be compared to ratepayer costs to fully understand the value of this approach. Connecticut must coordinate with other states to consider cost-effective transmission investments in advance of further procurements (Strategy 4). The potential for transmission upgrades is discussed in more detail in Objective 5.

All of these contingencies are further addressed in the Strategies in Part II of this IRP, but the key conclusions provided by the analysis above are that Connecticut can feasibly reach a 100% Zero Carbon Target by 2040, and should therefore enact this goal into statute (Strategy 1), while also pursuing reform of wholesale electricity markets to ensure the efficient deployment of new resources needed to meet this decarbonization goal, and equitable mechanisms to share the costs of retaining existing resources like Millstone (Strategy 2). Additionally, Connecticut should pursue changes to the State's RPS that will enhance its ability to meet the 100% Zero Carbon Target at a lower cost to ratepayers. This includes investigating whether it is in the best interest of ratepayers to retain RECs procured by the EDCs, on behalf of all ratepayers (Strategy 7); increasing the integrity of the RPS compliance obligation by eliminating the impact of behind-the-meter resources (Strategy 8); and phasing down the value of biomass RECs eligible as a Class I renewable energy source to diversify the resources supported by Connecticut's RPS (Strategy 14).

Finally, it is worth noting that Connecticut's statutory targets to reduce GHG emissions by at least 10 percent by 2020, 45 percent by 2030, and 80 percent by 2050 are statewide, economy-wide targets.[51] As detailed above, the State has enacted a number of policies, implemented through the state's two EDCs, to advance these goals in the electric sector. Such policies include the RPS, energy efficiency investments through the C&LM programs, grid-scale renewable and zero carbon energy procurements, the LREC/ZREC program, and the RSIP program, among others. Together these initiatives have contributed to reducing electricity-sector GHG emissions 29 percent since 1990, 36 percent since their peak in 1997, and 31 percent since 2001.[52] Electric ratepayers of the state's EDCs fund the programs described above as well as the Millstone contract, thus, those ratepayers' contributions to the GWSA are clear.

Connecticut's municipal electric cooperatives serve approximately 6 percent of the state's electric supply.[53] While this IRP only addresses the electricity supply for the state's EDCs, the collective contributions of the state's municipal electric cooperatives towards the GWSA economy-wide targets are relevant to determining the relative decarbonization investment required by the state's EDCs to achieve electric sector emission reductions towards the GWSA goals. Municipal electric cooperatives

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[51] Conn. Gen. Stat. Sec. 22a-200a.

[52] Connecticut DEEP, "2017 Connecticut Greenhouse Gas Emissions Inventory," published 2020, https://portal.ct.gov/-/media/DEEP/climatechange/2017_GHG_Inventory/2017_GHG_Inventory.pdf

[53] U.S. Energy Information Administration, 2019, "Annual Electric Power Industry Report, Form EIA-861 detailed data files," *available at*: https://www.eia.gov/electricity/data/eia861/

are developing programs for decarbonization, as indicated by a presentation by the Connecticut Municipal Electric Energy Cooperative (CMEEC)[54] and written comments submitted by CMEEC in this IRP proceeding,[55] albeit at a pace that is "slower and more considered" than the EDCs.[56] CMEEC further stated that it and its customers should be held accountable for compliance with the GWSA and Governor Lamont's Executive Order 3, but at an approach and timeline tailored to their customers' needs. Currently, the municipal electric cooperatives do not have reporting requirements tied to the GWSA, despite the fact that the GWSA applies statewide.[57] In its written comments, CMEEC offered to submit reports to DEEP on the progress of its carbon reduction in a manner that will allow DEEP to account for such contributions in determining progress toward the State's goals. Enabling such reporting requirements for the municipal electric cooperatives would provide more complete information for them as well as for DEEP, PURA, and the EDCs, to help all parties determine and coordinate the respective amount of investment required in the state's electric sector to meet the state's economy-wide targets (Strategy 1).

Objective 2: Securing the Benefits of Competition & Minimizing Ratepayer Risk

As discussed in Objective 1, Connecticut has made substantial progress over the last two decades in reducing carbon emissions from the electricity sector. Over the coming two decades, additional deployment of clean energy resources is needed to achieve the necessary scale of emission reductions to combat climate change. This IRP focuses on ways to achieve that deployment at minimal cost, and with maximum benefit, to Connecticut ratepayers.

Unfortunately, Connecticut's participation in the regional wholesale electricity market constructs, as presently designed and implemented by ISO-NE, has become a significant barrier to cost-effective clean energy deployment strategies, while increasing regional reliance on natural gas to an extent that has threatened reliability. As a result, Connecticut ratepayers are exposed to greater risk and duplicative costs. This section examines these challenges, including the circumstances that have led to this point, implications for state jurisdictional clean energy programs such as the Renewable Portfolio Standard, and potential process and substantive improvements that are needed to realign state and regional markets, for the benefit of Connecticut's ratepayers.

Connecticut's Aims for Restructuring

In the late 1990s, Connecticut undertook efforts to restructure (or "deregulate") its electric industry with the intent of harnessing cost savings through (1) participation in a competitive wholesale marketplace for electricity generation, and (2) providing for competition and consumer choice in retail

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[54] See, Presentation by Connecticut Municipal Electric Energy Cooperative in DEEP's January 22, 2020 technical meeting related to this IRP, *DEEP Technical Meeting Integrated Resource Plan CMEEC Insights*.
[55] CMEEC Written Comments, submitted October 29, 2019. http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/51c7b27775ac0827852584a8005e43e8/$FILE/Ltr%20DEEP_IRP%20Comments_10-29-2019.pdf
[56] Id.
[57] As recipients of funding from the RGGI proceeds, municipal electric cooperatives do have reporting requirements related to their expenditures of those funds. See RCSA § 22a-174-31(f)(6)(C)(ii).

electricity sales. Before deregulation, Connecticut's utilities were vertically integrated monopolies that owned the generation, transmission, and distribution of energy. The costs and risks of any investments made by the utilities were placed directly on ratepayers. Thus, a central aim of deregulation was that ratepayers would no longer be responsible for paying for cost overruns, obsolete technology choices and stranded assets associated with monopoly utilities developing power plants on a cost-of-service basis. Instead, private ("merchant") power developers would compete in a deregulated market, taking on the risks and rewards of their investments, and ratepayers would reap the benefits of lower cost electricity supplied through a more efficient market.

In the decades since its inception, the regional electricity market, which is administered by ISO-NE and overseen by the Federal Energy Regulatory Commission (FERC), has evolved—at times over Connecticut's strong objection—from a tool for the achievement of shared reliability and cost savings, to a system that impairs Connecticut's ability to achieve its clean energy goals and maintain grid reliability in a cost-effective manner.[58]

The regional market's design has evolved primarily around the investment needs of natural gas plants, allowing them to receive capacity payments in spite of their inability to run when called upon during winter cold snaps due to limited fuel availability. As a result, the region's reliance on natural gas plants has greatly increased, thwarting the entry of renewable and state-sponsored resources. The outcomes of the existing market are thus incompatible with Connecticut's long-term goals.

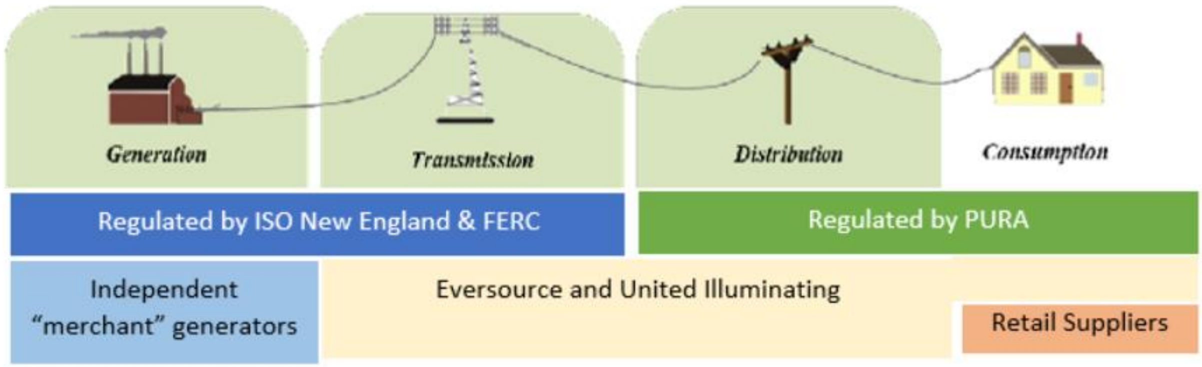
Changing market rules have also intruded on the states' lawful authority under the Federal Power Act (FPA), undermining state authority over resource selection. Over time, ISO-NE market rules that recognized states' authority to self-supply outside of the market have been eliminated, while other rules, originally designed to prevent market manipulation by participants, are now being used inappropriately to hinder states' efforts to implement clean energy laws. The result is that Connecticut ratepayers must now pay twice to receive the same service need: once through standard service or alternative retail supply offers for Connecticut's share of the costs of ISO-NE markets, and again through a component of UI and Eversource distribution rates for the clean energy resources that Connecticut has had to contract with directly in order to achieve the State's laws and mandates, as further set forth in Objective 3 below.

The Regulatory Framework: Before and After Deregulation

The interstate electricity market is composed primarily of generators, which produce electricity; transmission providers, which deliver electricity from generators to re-sellers and purchasers; and load serving entities (LSEs), which are either the EDCs or competitive electric suppliers that deliver and sell electricity to retail customers.[59]

[58] ISO-NE administers separate markets for energy, capacity, and ancillary services.
[59] *Allco Fin. Ltd. v. Klee*, 861 F.3d 82, 88 (2d Cir. 2017) (*Allco*).

Figure 2.1: The Regulatory Structure after Deregulation



The Federal Power Act (FPA) divides regulatory authority over these segments among federal and state authorities, and "envisions a federal-state relationship marked by interdependence."[60] The FPA vests with the FERC exclusive regulatory authority over both the "transmission of electric energy . . . and the sale of such energy at wholesale in interstate commerce."[61] The Federal Energy Regulatory Commission's regulatory authority "extend[s] only to those matters which are not subject to regulation by the States."[62] States "regulate energy production,"[63] including "questions of need, reliability, cost, and other related state concerns,"[64] as well as other local activities, including local distribution facilities,[65] and retail sales.[66]

Changes at the state and federal level in the mid-to-late 1990s resulted in significant restructuring of the electric industry in Connecticut and the broader New England region. Prior to 1998, Connecticut's EDCs were vertically integrated monopolies that recovered the costs of generation and distribution assets from electric ratepayers based on the "cost of service" plus a reasonable rate of return, all of which was regulated by the State's Department of Utility Control (DPUC; now the Public Utilities Regulatory Authority, or PURA). However, during the late 1970s through the 1990s, several converging trends caused policymakers to reconsider the vertically integrated monopoly model. Nuclear power plants had been hailed as an energy source that would make electricity "too cheap to meter." However, soaring cost overruns associated with new nuclear construction caused significant ratepayer impacts on those utilities that had invested in nuclear energy. Ratepayer risks associated with building large multi-unit plants on a cost-of-service basis caused policy makers to consider the economics of cheaper, smaller-

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[60] *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1300 (2016) (*Hughes*) (Sotomayor, J., concurring).
[61] 16 U.S.C. § 824(b)(1). The Public Utility Regulatory Policies Act of 1978 carved out a limited exception to the FPA that permits states to set wholesale prices for certain cogeneration facilities and small power production facilities less than 80 MW that sell power to local electric utilities, so long as those prices reflect a utility's avoided costs. *See* 16 U.S.C. § 824a-3.
[62] 16 U.S.C § 824(b)(1). FERC's regulation of wholesale transactions does not consider environmental impacts. *Grand Council of the Crees v. FERC*, 198 F.3d 950, 957 (D.C. Cir. 2000).
[63] *Hughes* at 1299, 1300 (Sotomayor, J., concurring).
[64] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 194, 205 (1983). *See also Californians for Renewable Energy, Inc. v. CAISO*, 117 FERC ¶ 61,072, P 10 (2006) (state has authority over generation facilities and environmental impacts).
[65] *Conn. Light & Power Co. v. FPC*, 324 U.S. 515, 531 (1945).
[66] *Hughes* at 1292; *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 766 (2016).

scale fossil generation to reduce risk and lower costs. At roughly the same time, the perceived success of deregulating the telecommunications and airline industries and the belief that competition in the electric generation industry would lower costs and shift risk away from ratepayers. [67]

At the federal level, FERC took action to facilitate wholesale competition and ensure fair and nondiscriminatory access to transmission services.[68] Further, FERC encouraged the establishment of independent system operators (ISOs) and Regional Transmission Operators (RTOs) to operate regional transmission grids on behalf of transmission owners, and to facilitate market-based wholesale electric rates for the efficient management and reliable operation of the transmission system.[69] The Commission oversees ISO/RTO markets, and is in charge of approval of initial market rules and design. Changes in either also require FERC approval.

At the state level, with the enactment of Public Act 98-28 in 1998, Connecticut joined 17 states and the District of Columbia in deregulating retail electricity sales and requiring the divestment of all utility generation assets.[70] The objective of the Act was to no longer source conventional power generation on a cost-of-service basis funded by captive ratepayers, with the intent of harnessing the benefits of power supply competition, including lower prices and reduced risk for ratepayers.[71] While Public Act 98-28 directed utility divestment of generation, Connecticut retained authority over the State's generation mix. Section 25 of the Act established the state's Renewable Portfolio Standard, which required increasing percentages of Connecticut's load to be supplied by Class I and Class II renewable energy resources. Section 33 of the Act established funding for C&LM programs run by the electric distribution companies.

The Department of Public Utility Control's implementation of the deregulation statute focused on divestment of utility generation assets and establishing a competitive market for retail supply offers. The intent was that by requiring the utilities to divest their generation assets, a competitive retail supply market would emerge, thus reducing costs to ratepayers. However, because many of the generation assets held by the utilities had higher book values than market values, the utilities were left with "stranded" costs. These stranded costs were allowed to be recovered from ratepayers through the Competitive Transition Assessment (CTA) charge, which were in excess of $2.1 billion for the EDCs nuclear assets alone.[72]

New England's Electricity Markets: The Early Years

Following the establishment of ISO-NE, the New England wholesale electricity markets opened on May 1, 1999.[73] At their inception, the wholesale markets involved primarily energy and ancillary services (E&AS) markets, and a monthly capacity auction intended to ensure resources would be available to

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[67] *Resource Assessment of Millstone Pursuant to Executive Order No. 59 and Public Act 17-3*, PURA Docket 17-07-32, pp. 6-8.
[68] *See, e.g.,* FERC Orders 888 and 889; and FERC Order 2000.
[69] FERC Order 2000.
[70] Vermont did not deregulate, and New Hampshire did not require its regulated utilities to divest their generation assets.
[71] *See* P.A. 98-28 § 2; https://www.cga.ct.gov/2006/rpt/2006-R-0526.htm
[72] *Resource Assessment of Millstone Pursuant to Executive Order No. 59 and Public Act 17-3*, PURA Docket 17-07-32, pp. 7-8.
[73] *New England Power Pool*, 100 FERC ¶ 61,286 (2002).

produce energy in the future for resource adequacy.[74] Upon its formation as an RTO, ISO-NE entered into a legal document known as the Participants Agreement, which formalized a stakeholder process for input and advice to ISO-NE by New England Power Pool (NEPOOL) participants (a group of utilities, generation suppliers, transmission owners, and end users), as well as individual market participants that are not members of NEPOOL. ISO-New England's market rules and operations are vetted by these stakeholders through this process.

In the early years of ISO-NE operations, pre-existing infrastructure deficiencies left the region dependent on out-of-market actions to preserve reliability. For example, at the time, southwestern Connecticut was experiencing congestion caused by transmission constraints. In order to remediate this congestion and ensure that generators required for reliable system operations would continue to be online, ISO-NE entered into numerous reliability-must-run (RMR) agreements with needed resources that were threatening retirement. Generators operating under RMR agreements are obligated to remain in operation for a period of time in exchange for the revenue certainty provided by a contract, cost-of-service rate. The above market costs were paid for entirely by Connecticut ratepayers. Following the submission of RMRs covering more than 1,700 megawatts (MW) of generating capacity located within Connecticut (and particularly the constrained southwest Connecticut area), FERC expressed concern that the widespread use of RMR agreements was inhibiting the functioning of the region's competitive markets.[75] In response, FERC directed that a location-specific capacity requirement be developed.[76] This market mechanism would provide generators with an additional revenue stream, thereby helping to ensure that needed facilities would remain in operation without the need for out-of-market RMR agreements. Subsequent region-wide negotiations and litigation at FERC ultimately led to the creation of the Forward Capacity Market (FCM) structure—a version of which is in place today.[77, 78]

The Mandatory Capacity Market Construct

The Forward Capacity Market established annual capacity auctions to procure, three years in advance, sufficient capacity to meet the region-wide, annual Installed Capacity Requirement (ICR)[79] during an ensuing, one-year commitment period.[80] To achieve this purpose at ”least cost,” ISO-NE administers an annual, descending clock auction—the Forward Capacity Auction (FCA)—in which supply resources compete to obtain Capacity Supply Obligations (CSOs)—the responsibility to provide electric energy during the relevant commitment period if called upon to do so. In procuring a mix of resources to satisfy the region's resource adequacy needs, the FCA treats all capacity within a zone as fungible. Resources are selected based on one criterion—cost—and without regard for a resource's contribution to fuel diversity, technology, or emissions characteristics. Even the focus on ”least cost” is misleading. The capacity market is designed around the relatively low fixed cost and high variable cost of natural gas

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[74] *Devon Power LLC*, 115 FERC ¶ 61,340 P 5 (2006) (describing New England's capacity procurement mechanisms in place between 1998 and 2002).
[75] *Id., at* P 29, 31
[76] *Id.*
[77] *Devon Power LLC*, 103 FERC ¶ 61,082, PP 29, 31 (2003).
[78] *Devon Power LLC*, 115 FERC ¶ 61,340 (2006) (subsequent history omitted).
[79] The ICR is "the level of capacity required to meet the reliability requirements defined for the New England Control Area." ISO-NE Tariff § I.2.2.
[80] *See Devon Power LLC*, 115 FERC ¶ 61,340 (2006), *order on reh'g*, 117 FERC ¶ 61,133 (2006), *aff'd in relevant part sub nom. Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464 (D.C. Cir. 2008).

generation as opposed to the tendency of higher fixed cost and zero variable cost of zero carbon resources.

The cost of the capacity purchased through the auction is paid by load-serving entities (LSEs) in proportion to each LSE's load-share of the region's total capacity requirements.[81] In creating a new revenue stream for generators, the FCM was intended "to [address] the compensation problems faced by generating resources that are needed for reliability but could not obtain sufficient revenues in the markets to continue operation."[82] At its inception, a key element of the FCM was the right on the part of LSEs to use owned or contracted-for generation resources to offset CSOs, thereby effectively reducing the amount of capacity the LSE must purchase from the auctions.[83] In other words, an LSE had the ability to satisfy its capacity supply requirements through arrangements outside the FCM, and to procure through the FCM any additional capacity necessary to meet the LSE's residual needs (those beyond the contracted-for amounts). The FCM design thus did not overturn—but instead accommodated—state generation policies. If a state directed its EDCs to purchase capacity from a specific resource or type of resource, the self-supply rights preserved in the original FCM design meant that the EDC could use those contracts to offset the amount of capacity it was obligated (as an LSE) to purchase through the FCM.

Over the past decade, the self-supply rights that were originally a centerpiece of the settlement that created the FCM have been gutted. Under the current capacity market design, new self-supplied resources must meet minimum offer bid requirements. The MOPR sets a price floor below which no new entrant may offer its capacity unless it can demonstrate that its actual costs fall below that floor price. Higher bids increase the risk that a resource will not clear the auction; capacity that fails to clear is not counted toward meeting the LSEs' capacity requirement.

To guarantee that a resource that has been contracted for outside the auction will clear the FCA and be counted toward satisfying a part of an LSE's capacity obligations, an LSE offering that capacity into the FCA typically would seek to offer as a "price taker"—that is, the resource would be willing to stay in the auction and take on a capacity obligation at any price, no matter how low. Application of the MOPR, however, prevents these resources from participating as price takers, and instead requires them to bid at their going-forward costs, *without* taking into account the revenues these resources receive through their state-sponsored contracts. This effectively prices zero carbon resources like wind and solar out of the market. The MOPR thus creates significant risk that the LSE's customers will have to pay for capacity twice for resources supporting state policy goals: once through the long-term contract to secure that capacity, and a second time through the FCM, because only FCM-cleared capacity is counted toward an LSE's capacity obligations.

Mitigation measures like ISO-NE's MOPR are intended to prevent the inappropriate exercise of market power and thus protect against artificial price suppression and other efforts to distort the market price.[84] But ISO-NE's MOPR has gone well beyond its market-protection purposes, and is applied to state-sponsored resources that are not being procured to exert market power or suppress FCM prices.

[81] *Id.* P 20.
[82] *Id.* P 62.
[83] *Id.* P 20.
[84] *See ISO New England*, 158 FERC ¶ 61,138, P 48 (2017) ("The purpose of the [MOPR] is to prevent net buyers, in general, from bidding resources in such a manner as to suppress FCM prices").

The minimum bid rules approved by FERC and in place in New England have confused unlawful "price suppression" with the natural price-reducing effect of states' lawful efforts to pursue their legitimate policies and buyer-side preferences that increase the availability of low-cost and clean supplies.

The MOPR effectively prohibits the states from exercising their authority under the FPA to choose their preferred source of generation. FERC's position is that all electrons are the same regardless of where the generation is coming from and should be valued the same.[85] Most New England states have rejected FERC's policy position through enactment of decarbonization legislation saying, in effect, that not all electrons are the same and that the states prefer electrons from zero carbon resources. Because the FPA grants FERC authority over wholesale energy sales in interstate commerce, state laws that are found to intrude on FERC markets are likely to be preempted by FERC-approved tariffs. As a result, the states are forced to work outside the market and incur significant extra costs as FERC has, in recent years, been very active in approving tariff rules that undermine state policy goals. This is the equivalent of the federal government directing that if states want to buy electric vehicles, they also have to buy combustion engine vehicles even if those combustion vehicles are not needed and would remain in the garage.

Conflict between State Policies and ISO-NE Markets

As noted above, the FCM construct focuses exclusively on selecting "least-cost" resources using a narrow calculation that excludes state revenues (which lower a resource's going-forward costs of providing capacity), favors natural gas generation, and ignores externalized environmental and other costs. This design does not make qualitative distinctions among resource types (e.g., on the basis of whether a resource is carbon-emitting). In addition, because the FCM has become the exclusive procurement mechanism for capacity in ISO-NE,[86] it is, by design, in direct conflict with state policies that seek to value criteria other than cost. To meet state policy mandates, states (and their ratepayers) must therefore support development of their preferred resources outside the FCM, and pay both for those resources and for FCM-selected capacity.[87] The New England states (through the New England States Committee on Electricity or "NESCOE") have argued that applying the MOPR to state-supported resources will require ratepayers to pay for more capacity than is needed, and at excessive prices.[88] ISO-New England disagreed, asserting that state authority would have to give way when it conflicts with market design—and not the other way around:

> The primary reason consumers might pay for more capacity than is needed is because the state-sponsored resources are unlikely to clear in the FCA based on costs, but will be built anyway pursuant to state initiatives. If the states choose to build uneconomic

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[85] 169 FERC ¶ 61,239 https://www.pjm.com/-/media/documents/ferc/orders/2019/20191219-el16-46-000-el18-178-000.ashx

[86] ISO-NE Tariff § III.13 ("To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1").

[87] While the sponsoring consumers bear those extra costs, the fuel diversity, resilience, and other characteristics of the sponsored resources tend to benefit the entire market.

[88] *See, e.g. New England States Committee on Electricity v. ISO New England Inc.*, Complaint and Motion to Consolidate Proceedings of New England States Committee on Electricity (Dec. 28, 2012), Docket No. EL13-34-000 and ER12-953-001, eLibrary 20121228-5266.

> resources outside of the FCM pursuant to current or future initiatives to further various policy interests, the states, not the FCM, are responsible for the procurement of redundant capacity.[89]

As described in more detail in the following sections, this hubristic perspective by the ISO-NE represents a fundamental misunderstanding of cooperative federalism and the delicate balance that Congress struck when enacting the Federal Power Act.

Connecticut's Environmental and Clean Energy Policies

Preventing environmental damage resulting from energy generation has long been a State policy in Connecticut. Public Act 98-28, the same statute that deregulated Connecticut's energy sector, established Connecticut's energy efficiency programs, the Clean Energy Fund (predecessor of the Connecticut Green Bank), and the State's Renewable Portfolio Standards (RPS). The Act explicitly declared that "the generation of electricity must be achieved in a manner that does not endanger the public health or safety and that minimizes negative environmental impacts."[90] Subsequently, in 2004, and revised in 2008 and 2018, the State set greenhouse gas emission reduction as an important State policy and established economy-wide greenhouse gas emission reduction targets for 2020, 2030, and 2050.[91]

Beginning in 2008, Connecticut's IRP observed that, despite the State's ambitious renewable energy procurement targets, "the growing demand for renewable electric generation created by these targets may outpace the development of eligible supplies," needed to displace conventional generation.[92] The 2012 IRP projected a gap between available renewable energy supply and the amount of renewable energy needed to meet Connecticut's targets.[93] Previously, the 2010 IRP had also concluded that RECs, energy, and capacity market revenues would be insufficient to meet Connecticut's clean energy goals and displace unneeded fossil generation.[94] This finding also indicated that the "optimal strategy for meeting the State's RPS requirement is to procure renewable energy as a part of a New England regional market."[95] Thus, the State enacted policy mechanisms in furtherance of these environmental and climate goals, including authorizing State-run procurements for long-term energy and REC contracts for a variety of renewable and zero carbon resources beginning in 2013.[96]

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[89] *New England States Committee on Electricity v. ISO New England Inc.*, ISO New England Inc.'s Answer in Opposition to Motion To Consolidate, Motion for Summary Dismissal Of Complaint, and Answer To Complaint at 13 (Jan. 14, 2013), Docket No. EL13-34-000 and ER12-953-001, eLibrary No. 20130114-5160.

[90] Conn. Gen. Stat. § 16-244(6) & (9).

[91] P.A. 04-252, *An Act Concerning Climate Change* (2004); P.A. 08-98, *An Act Concerning Connecticut Global Warming Solutions* (2008). P.A. 18-82, *An Act Concerning Climate Change Planning and Resiliency* (2018).

[92] The Brattle Group; Connecticut Light & Power; The United Illuminating Company. 2008. *Integrated Resource Plan for Connecticut*. https://www.ct.gov/deep/lib/deep/energy/irp/2008_irp.pdf

[93] Connecticut Department of Energy and Environmental Protection. 2012. *2012 Integrated Resource Plan for Connecticut.* https://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

[94] The Brattle Group; Connecticut Light & Power; The United Illuminating Company. 2010. *Integrated Resource Plan for Connecticut*. https://www.ct.gov/deep/lib/deep/energy/irp/2010_irp.pdf.

[95] The Brattle Group; Connecticut Light & Power; The United Illuminating Company. 2010. *Integrated Resource Plan for Connecticut*. https://www.ct.gov/deep/lib/deep/energy/irp/2010_irp.pdf.

[96] Conn Gen. Stat. §§ 16a-3f; 16a-3h; 16a-3h; 16a-3j; 16a-3m. Public Act 19-71, *An Act Concerning the Procurement of Energy Derived from Offshore Wind* (2019).

In addition to pursuing increased renewable generation development to meet Connecticut's climate goals, Connecticut has undertaken to "conserve energy resources by avoiding unnecessary and wasteful consumption," and "consume energy resources in the most efficient manner feasible."[97] As early as 2008, the IRP has emphasized aggressive pursuit of demand-side management resources such as energy efficiency as a cost-effective means to reduce customer costs, gas usage, and environmental emissions," while increasing economic activity in the state.[98]

Connecticut has at times been compelled to take action to accomplish reliability and other goals. In 2005, facing increasing electric rates and congestion in certain areas of the state, the legislature passed June Special Session Public Act 05-01 which authorized grants for customer-side distributed resources and long-term contracts with new generating facilities to reduce federally mandated congestion charges (FMCCs).

Connecticut also considers fuel diversity—i.e., utilization of a variety of fuel sources to mitigate risk associated with fuel-related price volatility and supply contingencies—and fuel security—i.e., the reliable supply of the various fuels used to generate the region's electricity—as primary operational concerns in its IRPs. In 2008, the IRP highlighted two harmful potential implications from overreliance on gas: first, that it exposes Connecticut ratepayers to "high and uncertain power costs, because gas is the price-setting fuel for electricity," and, second, that "using large amounts of natural gas for electricity generation may increase the potential of gas supply disruption in the winter months when natural gas use peaks." These findings spurred a recommendation for contractual, or ownership arrangements with non-gas baseload generating resources to maintain fuel diversity and mitigate gas dependence.

Connecticut's 2014 IRP emphasized the risk of the region's natural gas-fired generators "not contracting directly for the gas capacity they need to run," which causes the "wholesale spot market price of natural gas delivered to New England [to be] significantly higher," thereby increasing retail rates for ratepayers across the region. This concern is at its peak during cold winter periods when gas supply is also being used to meet thermal loads. For example, the wholesale price of natural gas was about $1-3/MMBtu before 2012/13 and $8/MMBtu in 2012/13, but rose to almost $14/MMBtu in December through February of 2013/14, largely driven by the extended "polar vortex" cold snap. These increased natural gas prices cost New England ratepayers an estimated additional $3 billion in wholesale electricity costs. To address this risk, Connecticut enacted Public Act 15-107, which allowed DEEP to solicit proposals for a variety of resources that could help address fuel constraints, including natural gas resources as well as energy efficiency and Class I renewable energy sources.

In addition, Connecticut has contracted for 10.9 million MWh of energy from nuclear power and an additional 7 million MWh of environmental attributes from nuclear power, which in total is the equivalent of more than 65 percent of EDC load.

[97] Public Act 92-106, *An Act Concerning the External Costs and Benefits Associated with Energy Generation and Revenues Received by an Electric Public Service Company Pursuant to the Clean Air Act Amendments of 1990,* amended this section to provide additional preference to conservation over other equivalent energy alternatives by adding Subdiv. (9).

[98] The Brattle Group; Connecticut Light & Power; The United Illuminating Company. 2008. *Integrated Resource Plan for Connecticut*. https://www.ct.gov/deep/lib/deep/energy/irp/2008_irp.pdf

ISO-NE Market Design Changes

Previous iterations of the ISO-NE market design have included a partial accommodation for state-preferred resources. Under the ISO's Renewable Technology Resource (RTR) exemption, up to 200 MW of renewable resources were permitted to enter the FCM without being subject to the MOPR.[99] In the event that the full 200 MW was not used in a single year, the unused portion of the exemption amount was permitted to roll forward for use in later years, subject to a 600 MW cap on those carry-overs. While imperfect, this mechanism offered at least a partial solution to the region's "pay twice" problem. State-sponsored resources utilizing the RTR exemption could bid into the FCM at a price reflective of their true marginal cost—i.e., the increased cost associated with providing capacity, recognizing that the resource had already committed, through state-sponsored contracts, to provide energy.[100]

In 2018, however, the ISO requested—over Connecticut's strong objection[101] – that FERC eliminate the RTR exemption and establish a secondary FCM "substitution auction".[102] In the substitution auction, resources that do not clear the primary FCA due to the MOPR are given a second opportunity to enter the capacity market by trading into, or taking over.[103] Connecticut opposed the substitution auction because it provides a windfall for exiting generators, and creates uncertainty for new resources about when existing generators might exit.[104] In the two years that Competitive Auctions with Sponsored Policy Resources (CASPR) have been in operation, these concerns have largely born out: only 54 MW of state-sponsored resources have cleared through the substitution auction.[105]

FERC has likewise been unsympathetic to state policies. In December 2019, FERC directed sweeping changes to the design of the capacity market administered by ISO-NE's mid-Atlantic counterpart, PJM Interconnection (PJM), to address the participation of resources receiving out-of-market state support.[106] FERC directed PJM to expand the scope of its MOPR (currently applied primarily to new, natural gas-fired resources) to include both new and existing resources, whether internal or external, that receive or are entitled to receive a state subsidy"[107] The Commission's definition of state subsidy is expansive, and includes payments or other financial benefits awarded through a state-mandated or state-sponsored process, either derived from or connected to the procurement of capacity, an attribute

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[99] *ISO New England Inc.*, 147 FERC ¶ 61,173 (2014) (subsequent history omitted).
[100] *ISO New England Inc.*, Docket No. ER18-619-000, Protest of the Connecticut Public Utilities Regulatory Authority, the Connecticut Department of Energy and Environmental Protection, and the Connecticut Office of Consumer Counsel, Affidavit of Cliff W. Hamal at ¶ 29 (Jan. 29, 2018) (Hamal Affidavit), eLibrary No. 20180129-5363.
[101] *Id.*
[102] ISO New England Inc., 162 FERC ¶ 61,205 (2018).
[103] *See generally,* ISO New England Inc., *Competitive Auctions with Sponsored Policy Resources (CASPR) Key Project* (last accessed Feb. 7, 2019), https://iso-ne.com/committees/key-projects/caspr.
[104] Hamal Affidavit at ¶¶ 41-42.
[105] *See* https://www.iso-ne.com/static-assets/documents/2019/02/20190206_pr_fca13_initial_results.pdf and : https://www.iso-ne.com/static-assets/documents/2020/02/20200205_pr_fca14_initial_results.pdf.
[106] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) (PJM Order).
[107] PJM Order at P 50

of the generation of electricity, or otherwise supporting the construction of new capacity resources.[108,109]

If a PJM-style MOPR were adopted in New England, it could further exacerbate the “pay twice” problem by expanding the types of state support that triggers MOPR mitigation and applying the MOPR to new and existing resources. Instead of creating a market where a more diverse pool of resources can compete, this effectively ensures that the selection of natural gas power plants will continue to be selected by the FCM over renewable resources. This market structure creates significant environmental justice and air quality issues, all while artificially raising the cost of addressing them in the name of “fuel neutrality”.

ISO-New England’s Market Design Has Driven Overreliance on Natural Gas

At the same time that the ISO-NE has taken steps that inhibit states’ ability to secure a diverse resource mix reflective of consumer preference, ISO-NE has continued to drive the market in the direction of over-reliance on natural gas. While natural gas comprised only 6 percent of the region’s electric generation prior to restructuring, today, as shown below, nearly 50 percent of the region’s 34,637 MW of generating capacity is fueled by natural gas:[110]

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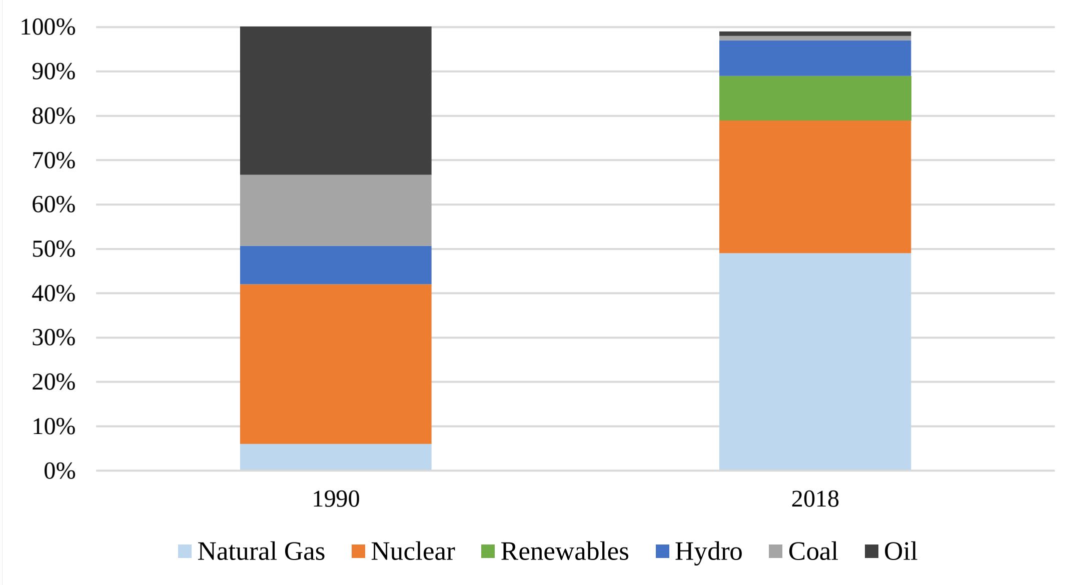
[108] Specifically, FERC proposes to define “State Subsidy” as:

[a] direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction. PJM Order at P 67.

[109] Commissioner Glick has pointed out the Commission‘s orders have been unsympathetic to state policies: “At this point, the die is cast. Today‘s orders make unambiguously clear that the Commission intends to array PJM‘s capacity market rules against the interests of consumers and of states seeking to exercise their authority over generation facilities. For all of the reasons discussed above, there orders are illegal, illogical, and truly bad public policy. “ PJM Order, at P 98. (Glick dissenting.)

[110] ISO New England. 2019 *Regional System Plan (Oct. 31, 2019).* https://www.iso-ne.com/system-planning/system-plans-studies/rsp/

Figure 2.2: New England's Electricity Generation Capacity[111]



Increased reliance on natural gas generation has resulted in incremental reductions of conventional air pollution and carbon emissions in the region due to its displacement of coal and oil. But this increased reliance on natural gas, paired with the market's continued failure to appropriately value renewable resources, and a regional natural gas pipeline system that has not kept pace with the growth in natural-gas-fired generation, has also created a severe supply-demand problem that has exposed the region to serious reliability and fuel security concerns, particularly during more extreme weather events. [112] The New England power system's fuel security weaknesses were exposed during a January 2004 "cold snap" in which "record-high winter electricity demand coincided with the unavailability of substantial quantities of [natural gas] generating capacity," and "pushed the electric system in New England close to its limits."[113] Since that time, gas resource development has continued, without any pipeline expansion—have meant that these concerns continue to persist.

Despite the region's limited gas pipeline infrastructure and the related reliability risk, ISO-NE has not considered fuel availability when qualifying gas-fired resources for participation in the FCA, or calculated how much capacity those gas resources can reasonably be expected to provide to the grid during cold weather when natural gas may not be available to generators.[114] Thus, the capacity purchased through the FCM may be unable to perform when needed—specifically, when the natural gas delivery system is constrained during cold-weather periods.[115]

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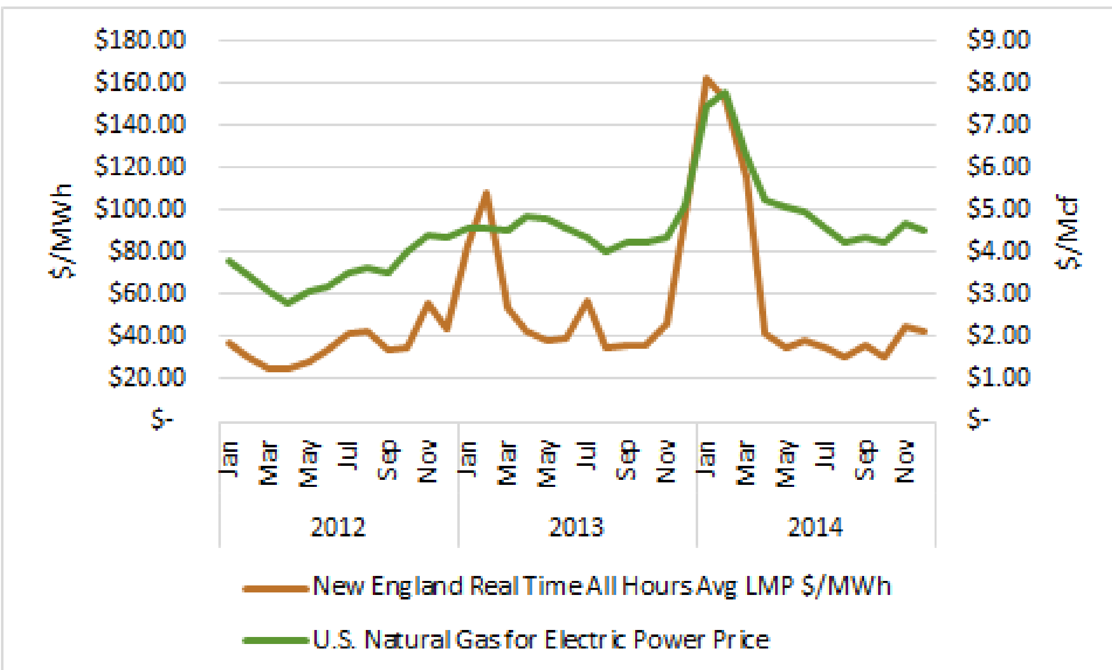
[111] ISO New England. 2015. *Energy and Peak by Source.*
[112] ISO New England. 2015. *AD13-7-000 and AD14-8-000 Fuel Assurance Report.* https://www.iso-ne.com/static-assets/documents/2015/02/Final_for_Filing__Fuel_Assurance_Report.pdf
[113] ISO-New England. 2004. *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap".* https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf
[114] However, the ISO does prorate the capacity value of wind and solar resources.
[115] Petition of ISO New England Inc. for Waiver of Tariff Provisions (May 2018 Petition), Brandien Test., Ex. ISO-1, at 11-12, ISO New England Inc., No. ER18-1509 (May 2, 2018), eLibrary No. 20180502-5089.

The region's gas dependence has also exposed consumers to significant price volatility. During the winter of 2013-2014, the "polar vortex" caused delivered gas prices to soar because of increased gas demand and supply constrains into New England. As a result, the cost of generation increased significantly to the point where the price of generation from burning gas and oil inverted, allowing oil units to set the locational marginal price (LMP) in more hours. The total wholesale generation cost of serving electric load in New England for the just the winter of 2013/14 was over $5 billion, compared to $5.2 billion for all of 2012. This was reflected in customers' retail rates the following year, which rose by 26 percent for Eversource customers, and 54 percent for United Illuminating (UI) customers. Figure 2.3 below demonstrates the relationship between natural gas prices and monthly average whole electricity prices over the course of 2012 to 2014. As demand for natural gas rapidly increased beginning in late 2013, prices spiked and resulted in a corresponding price spike for New England wholesale energy prices.

Figure 2.3: Average Monthly Electricity and Natural Gas Prices between 2012 & 2014[116, 117]



The ISO-New England's efforts to date to address the region's fuel security issues have been ineffective. In recent years, ISO-NE has sought and obtained FERC approval to spend tens of millions of ratepayer dollars on programs to pay fossil fuel-fired generation to firm up fuel supplies ahead of the 2015-2016, 2016-2017, and 2017-2018 winters.[118] ISO-New England also developed and obtained approval of its Pay-for- Performance (PFP) program to correct the FCM's failure to ensure that cleared capacity would

[116] U.S. EIA Wholesale Electricity and Natural Gas Market Data www.eia.gov/electricity/wholesale/#history
[117] ISO-NE Monthly Zonal Pricing Reports. https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/zone-info
[118] *See ISO New England Inc.*, 144 FERC ¶ 61,204 (2013) (approving winter reliability program for 2013-2014 winter); ISO New England Inc., 152 FERC ¶ 61,190 (2015) (approving winter reliability program for 2015-2016, 2016-2017, and 2017-2018 winters).

have the fuel to run when needed.[119] Under the PFP program, capacity resources are subject to penalties if they do not run when called upon during emergency, "shortage events." Ultimately, instead of resolving these issues efficiently, each of these initiatives have increased costs to ratepayers and the problems continue to persist.

The ISO-New England itself has acknowledged the inability of these measures to address the problem fully. The ISO-New England has concluded "even once fully implemented, PFP cannot be expected to resolve the region's fuel security challenges by itself."[120] In January 2018, ISO-NE issued its Operational Fuel-Security Analysis (OFSA), which "identified fuel-security risk—the possibility that power plants will not have or be able to get the fuel they need to run, particularly in winter—as the foremost challenge to a reliable power grid in New England."[121] Among other things, the OFSA concluded that fuel constraints and recent retirements of several of the region's large, non-gas resources had left New England exposed to potential rolling blackouts beginning in 2024 if any one of several "critical" facilities in the region were unavailable.[122]

The OFSA's findings prompted one of those critical resources, the Boston-area Constellation Mystic Power, LLC ("Constellation") Mystic power plant ("Mystic"), to use its status as the basis for obtaining an RMR agreement. In 2018, Constellation threatened to retire Mystic and its nearby liquefied natural gas (LNG) terminal supplier if it was not given a cost-of service contract at a rate that Constellation deemed sufficiently profitable. That threat induced ISO-NE to enter into a two-year RMR contract with Constellation that guarantees the plants' owners 100 percent of the Mystic plant's cost-of-service and more than 90 percent of the cost-of-service of the LNG- terminal. The contract is expected to cost consumers hundreds of million dollars a year, or approximately $484 million.[123] Roughly a quarter of these charges will be paid by Connecticut ratepayers, or approximately $121 million.

Clean energy resources, such as efficiency, hydropower, offshore wind coupled with storage, and nuclear generation, are scalable alternatives that help to reduce the region's natural gas dependence—a fact ISO-NE has acknowledged.[124] These resources also achieve important state climate and air quality goals. And yet, ISO-NE's actions continue to discount the value of those solutions, while increasing the costs to consumers to provide them.

In addition, despite the 2018 ISO-NE OFSA 125 that concluded the retirement of Millstone would lead to rolling blackouts during extended cold periods because the region would run out of fuel, the ISO-NE failed to propose any meaningful mechanism to retain the Millstone facility and share the costs fairly

[119] *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014).
[120] May 2018 Petition at 16.
[121] ISO New England Inc., Operational Fuel-Security Analysis at 4 (Jan. 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.
[122] *Id.* at 32.
[123] *See generally*, *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (2018).
[124] ISO New England Inc., Petition for Waiver of Tariff Provisions 24-25 (May 2, 2018), eLibrary No. 20180502-5089 ("There are many infrastructure solutions that can address the fuel system constraints in the region in the long term[,] . . . includ[ing] . . . firm renewable energy (e.g., imports of hydro energy, or off-shore wind coupled with significant electricity storage), and investments in energy efficiency measures").
[125] available at https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

across the region. Subsequently, Dominion announced that economic pressures put the Millstone units at risk of retiring. The ISO-New England and the current energy market construct failed to offer a solution to retain this generation asset, which ISO-NE itself determined was critical to the region's reliability, from retiring. The Connecticut General Assembly enacted Public Act 18-50, which authorized the entry by the State into a contract for Dominion Nuclear Energy's Millstone Generating Station in Waterford, Connecticut. The Department and PURA evaluated the impacts if Millstone were to shut down, reviewed Dominion's confidential financial records associated with the Millstone facility, and concluded that the plant was at risk of retiring. Given the alternative of catastrophic rolling blackouts, $5.5 billion in replacements costs and a 25 percent increase in greenhouse gas emissions if Millstone were to shut down, DEEP supported the selection and negotiation of a power purchase agreement (PPA) to prevent Millstone from retiring before 2029.[126] The State was able to cut the overmarket subsidy in half through contract negotiations. The contract is backstopped by Connecticut utilities and their ratepayers, but the contract ultimately benefits the entire New England region.

In sum, Connecticut embraced deregulation in 1998 as a means to secure generation supply through competition at a lower cost, and reduced risk, to the State's ratepayers. The State paid a high price for this opportunity, writing down $2.1 billion in losses with the sale of the utility-owned generation. The State did not intend to surrender its authority under the Federal Power Act to determine the resource mix serving its citizens and further State policy goals, evidenced by the multiple pieces of legislation passed by the General Assembly to increasingly direct the State's energy supply to a renewable and zero carbon mix. But slowly, over time, ISO-NE and FERC have undermined that authority by effectively eliminating the state's self-supply rights. At the same time, the ISO-NE market has struggled to maintain reliability, instead saddling Connecticut ratepayers with costly out-of-market RMR contracts in the mid-2000s; expanding the region's reliance on natural gas; and exposing ratepayers to retail price spikes, threats of rolling blackouts during periods of prolonged cold weather, and exercises of market power by non-pipeline natural gas resources such as the Mystic LNG facility as well as the Millstone nuclear facility. Approximately 90 percent of the equivalent of Connecticut's projected EDC load in 2025 is now under contract to nuclear and zero carbon resources needed to meet State clean energy goals and regional reliability needs, but the State continues to be assessed 100 percent of its load share of the ISO-NE market costs.[127] Wholesale energy market prices are at all-time lows, and the regional fuel security situation is greatly improved—benefits that the entire New England region enjoys as a result of Connecticut's investments. Connecticut has advocated vigorously in the ISO-NE stakeholder process and at FERC to oppose these inequities, but those concerns have largely been ignored. The present circumstance is inequitable, unjust, and unreasonable, and it cannot continue.

Connecticut finds itself at a crossroads, and is faced with a difficult choice: continue to push for changes to a broken market design through a process that has generally proven unresponsive to State needs, or pursue an exit from a regional arrangement that has become incompatible with the achievement of

[126] Connecticut DEEP and PURA. Resource Assessment of Millstone Pursuant to Executive Order No. 59 and Public Act 17-3; Determination Pursuant to Public Act 17-3. February 1, 2018. http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/a2d566dfd5533fed8525822700725e33/$FILE/DEEP-PURA%20FINAL%20Report%20and%20Determination%202-1-18.pdf

[127] The projected EDC load uses ISO New England CELT data, net of municipal EDC load, for the year 2025 as that is when all current contracted resources are expected to be operational.

Connecticut's long-term goals. In collaboration with the other New England states, Connecticut has been working toward a regional solution to these market design flaws that will account for Connecticut's and the region's policy objectives, including fulfillment of clean energy mandates. As the initial step in such a potential regional solution, Connecticut and the rest of the New England states recently announced a joint Vision Statement.[128] In this statement, the states announced their commitment to pursuing a new, regionally-based market framework that will account for and support the States' clean energy laws in a reliable and affordable manner. The Vision Statement laid out five fundamental principles that any such regional solution must reflect. This multi-state process has the potential to produce a unified market design that can finally secure a clean, reliable, affordable electricity supply for Connecticut ratepayers through a competitive regional market.

Securing the Benefits of Competition in State Jurisdictional Markets

Because the region's wholesale electricity markets have evolved in such a way that they are not procuring the types of resources needed to meet the State's clean energy and other public policy goals, Connecticut has, over the years, implemented a number of programs and mechanisms to drive investment in those resources. These programs include competitive procurements for grid-scale renewable resources and programs for behind-the-meter generation. Importantly, the State has maintained the same commitment to utilizing competition to achieve cost savings and minimize ratepayer risk when designing these state jurisdictional programs as it did in restructuring the generation sector in 1998. The continuing divergence of regional markets and state programs, and the accelerated focus on decarbonization objectives, has created opportunities for refinement of these programs to better serve ratepayers and address inequities. This section assesses recent trends and progress in these programs.

Connecticut's Renewable Portfolio Standard

Connecticut's RPS has served as a key policy tool in reducing the State's reliance on large, fossil fuel generators and spurring investment in alternative energy sources since 1998. The Renewable Portfolio Standard was designed to bring online renewable energy resources supporting State policy goals that were not otherwise being supported in the regional markets. The REC market was designed to provide the "missing money" between energy market revenues and the revenue necessary for a renewable energy project to come online. Each year, electric suppliers in Connecticut must comply with the RPS by procuring and properly settling the necessary amount of RECs to meet the percentage targets for each given RPS Class. REC market prices are primarily influenced by supply and demand for renewable energy resources. States establish their demand by setting RPS targets, signaling to the renewable energy market that there is willingness to pay for the development.[129]

However, REC sales to suppliers alone have historically been insufficient to receive financing to develop renewable energy resources because such investments are not made based on spot market pricing. Instead, renewable energy resources are developed based on long-term contracts for energy and/or RECs, which states support entering into to meet the RPS goals. The shift to long-term contracting as a means to achieve RPS and decarbonization goals led to Connecticut conducting a number of procurements to support renewable and zero carbon energy resources and provide the necessary

[128] The Vision Statement is available at [New England States Vision Statement | NESCOE](). In addition, Governor Lamont joined with five other New England governors to announce the joint effort in a joint statement, which is available at: http://nescoe.com/resource-center/govstmt-reforms-oct2020/.
[129] One REC is equivalent to one megawatt hour of energy produced by an eligible resource.

revenue certainty to these resources through long-term contracts, both at the grid-scale and distributed generation levels.

Competitive Procurements for Grid-Scale Renewable Resources

The Department conducted its first procurement of renewable energy in 2011 using authority from Section 127 of Connecticut Public Act 11-80. Section 127 directed that 30 MW of Class I renewables be procured through an open, competitive RFP, and the state's EDCs were authorized to own and operate no more than 10 MW each of that authority. The average price of solar projects developed by the EDCs was $212.79/MWh, while the price of the solar project selected by DEEP through a competitive procurement was $123.12/MWh. Since that time, DEEP has opposed utility-only procurements. Utilities—through their affiliates—are allowed to bid projects into the State's procurements, competing on equal footing with other non-utility bidders. While procurements in other states like Massachusetts are run by the utilities themselves, Connecticut has assigned to DEEP the responsibility for procurement of these resources, to maintain the competitiveness of the solicitation and act as a check on potential utility conflicts of interest.

Since 2011, DEEP has conducted nine procurements, resulting in contracts for 710 MW of grid-scale solar, 1,108 MW of offshore wind, 34 MW of incremental energy efficiency to the energy efficiency programs, 52 MW of fuel cells, energy and environmental attributes from 10.9 million MWhs of nuclear power, and additional environmental attributes associated with 2.85 million MWhs of nuclear power. Table 3.1 below shows DEEP's existing procurement authority, including how much of that authority has been utilized and how much authority is remaining. In total, DEEP is *authorized* by statute to procure up to 110 percent of the load associated with the state's two EDCs from renewable or zero carbon energy resources.[130] To date, Connecticut has procured the equivalent of 95 percent of the EDCs' load in the forms of energy and/or environmental attributes associated with renewable energy sources. Of these total procurements, 91 percent are from zero carbon resources.[131] A full list of projects resulting from DEEP's procurements that successfully negotiated contracts is included in Appendix A6.

Table 2.1: DEEP's Grid-Scale Procurement Authority

	Authorized (MW)	Authorized (MWh)	Authorized (% of Load)	Procured	Remaining
Section 6[132]			4.00%	2.74%	1.26%
Section 7[133]			5.00%	0.00%	5.00%
Section 8[134]			6.00%	5.85%	0.15%

[130] Based on an EDC load of 25,257,413 MWh in 2020. Eversource, Correspondence, 2019 Annual RAM Filing, PURA Docket No. 20-03-01, PURA Annual Review of the Rate Adjustment Mechanism of the Conn. Light & Power Co. (Apr. 8, 2020); The United Illuminating Co., Compliance Filing, Semi-Annual TAC, NBFMCC, and Umbrella Filing, PURA Docket No. 20-03-02, PURA Annual Review of the Rate Adjustment Mechanism of The United Illuminating Co. (Jul. 21, 2020).

[131] Based on projected load for the EDCs in 2025, when all current contracted procurements are expected to be operational.

[132] Conn. Gen. Stat. § 16a-3f. Eligible projects for this procurement include Class I renewable energy sources.

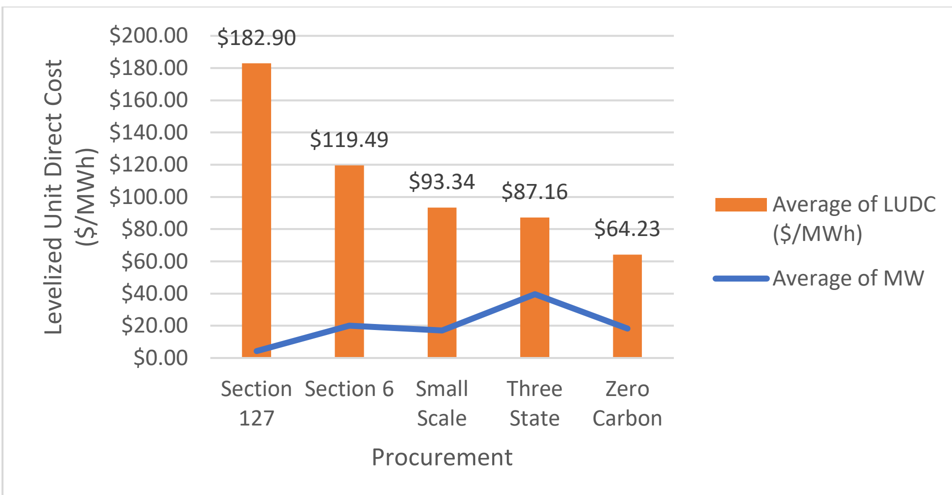
[133] Conn. Gen. Stat. § 16a-3g. Eligible projects for this procurement include Class I renewable energy sources and verifiable large-scale hydropower.

[134] Conn. Gen. Stat. § 16a-3h. Eligible projects for this procurement include run-of-the-river hydropower, landfill methane gas, biomass, fuel cell, offshore wind or anaerobic digestion, provided such source meets the definition of a Class I renewable energy source, or energy storage systems.

PA 15-107[135]			10.00%	3.22%	6.78%
PA 17-3[136]		12,000,000	47.51%	46.18%	1.33%
		Additional Millstone Environmental Attributes		*11.28%*	
PA 19-71[137]	2,000	9,460,800[138]	37.46%	14.69%	22.77%
Sec. 17 of PA 19-35[139]	10	83,220	0.33%	0.00%	0.33%
TOTAL			**110.30%**	**83.96%**[140]	**26.34%**

As the cost for developing and deploying zero carbon resources declines, DEEP has been able to capture these declines on behalf of all ratepayers through competitive procurements. From the first purchases for grid-scale solar in 2011 to its most recent procurement for grid-scale solar in 2019, DEEP saw the average price for selected projects decline 65 percent, from $182.90/MWh to $64.23/MWh (nominal). This rate of change is relatively consistent with national data trends, which have shown that during the same time period levelized PPA prices for utility scale solar have decreased by 74 percent.[141] Figure 2.4 shows the average selected price and average selected size of solar projects in recent competitive procurements. See Appendix A6 for details on Connecticut's solar procurements.

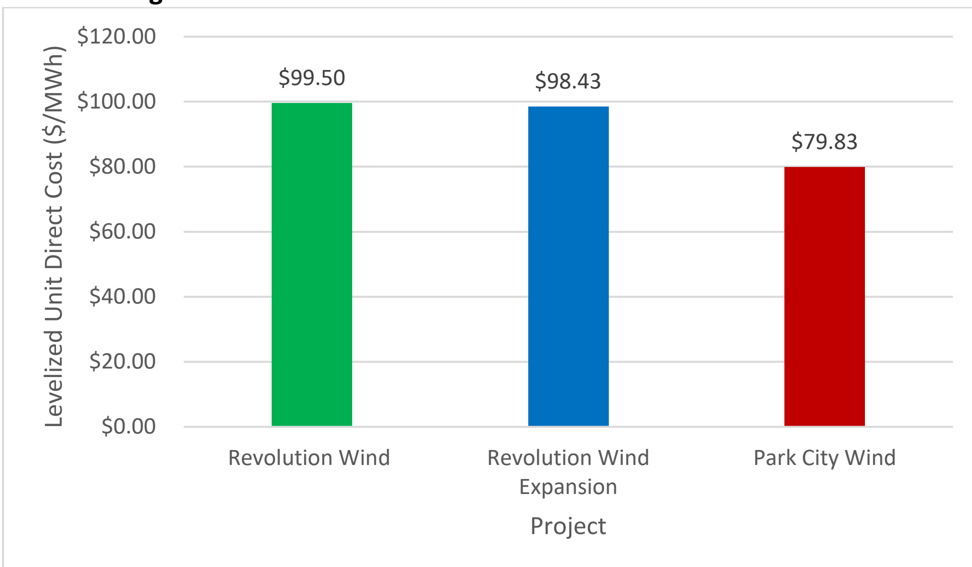
Figure 2.4: Average Price and MWs of Grid-Scale Solar Selected in Procurements[142]



[135] Conn. Gen. Stat. § 16a-3j. Eligible projects for this procurement include passive demand response, Class I renewable energy resources, Class III renewable energy resources, energy storage systems, and verifiable large-scale hydropower.
[136] Conn. Gen. Stat. § 16a-3m. Eligible projects for this procurement include nuclear, hydropower, Class I renewable energy sources, and energy storage systems.
[137] Conn. Gen. Stat. § 16a-3n. Eligible projects for this procurement include offshore wind and associated transmission.
[138] Assumes an OSW capacity factor of 54%.
[139] Conn. Gen. Stat. § 16a-3p. Eligible projects for this procurement include anaerobic digestion.
[140] Of the 83.96% total energy and/or RECs/environmental attributes under contract, 81.38% is associated with zero carbon energy.
[141] Lawrence Berkley National Lab. Utility Scale Solar 2019 Edition Report. 2019. *Available at* https://emp.lbl.gov/utility-scale-solar .
[142] The Section 6 procurement resulted in only one solar project selection, Fusion Solar. Thus, this bar is the actual project price, not an average price.

In addition, DEEP has seen price declines for offshore wind resources over an even shorter period. From 2017 to 2019, selected offshore wind project pricing declined 20 percent, from $99.50/MWh to $79.83/MWh (nominal).

Figure 2.5: Price of Offshore Wind Selected in Procurements



In order to meet energy policy and climate goals, the New England and surrounding states have conducted several procurements since 2009 to spur development of offshore wind and bring these resources online. Connecticut has been active in evaluating and procuring OSW resources as part of its efforts to meet its GWSA, including three project selections totaling 1,108 MW. This accounts for approximately 19 percent of the State's electric load under contract with its EDCs. The Department has authority to procure an additional 1,196 MW of OSW specifically under Public Act 19-71. Additionally, OSW is a Class I resource eligible under other DEEP procurement authority. Nearly 15 percent of EDC load is available for additional procurement authority for all Class I resource types, equivalent to 3.8 million MWhs, where OSW would be eligible.[143] Public Act 19-71 specifically requires DEEP to establish in this IRP the quantity of offshore wind energy needed, and timing and schedule of solicitations that seeks to procure that needed quantity of offshore wind, which is discussed in more detail in Part II.[144]

The New England states have selected and/or contracted for 3,142 MW of OSW, all of which interconnect at ISO-NE pool transmission facilities (PTFs). New York is siting 1,010 MW of OSW in New England waters with interconnections directly onto the New York grid. The Block Island project is the only operational OSW off the New England coast, and Vineyard Wind Phase 1 will be the next project to go through the BOEM permitting process. Table 2.2 demonstrates the wind procurements in the last decade. Costs per MWh have declined over the years while procurement size has grown for the New England states, as shown by the comparatively low costs of the Park City Wind contract Connecticut procured in 2019.

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[143] Assuming a capacity factor of 54%, this equals approximately 815 MW of offshore wind.

[144] Section 3, Public Act 19-71, An Act Concerning the Procurement of Energy Derived from Offshore Wind.

Table 2.2: Offshore Wind Projects Selected by Connecticut and Neighboring States

Project	Year Selected	Procuring State	MW	Levelized Unit Cost	
				Nominal $/MWh	2020 $/MWh
Park City Wind[145]	2019	CT	804	$75.59	$58.31
Mayflower Wind[146]	2019	MA	800	$77.76	$59.63
Empire Wind[147]	2019	NY	816	$118.64	$89.74
Sunrise Wind[148]	2019	NY	880	$110.37	$84.48
Revolution Wind[149]	2018	CT	200	$99.50	$79.04
Revolution Wind[150]	2018	CT	104	$98.43	$78.19
Vineyard Wind Phase 1[151]	2018	MA	400	$89.49	$72.52
Vineyard Wind Phase 2[152]	2018	MA	400	$78.61	$62.45
Revolution Wind[153]	2018	RI	400	$98.43	$78.19
Block Island Wind Farm[154]	2010	RI	30	$340.50	

The modeling results detailed in Objective 1 demonstrate that Connecticut's commitment to zero carbon resources through grid-scale competitive procurements has put the State on the path to successfully achieving its 100% Zero Carbon Target by 2040. Because of the success of these procurements, the model projects that new grid-scale resources would be needed in 2027 under the Base Load Balanced Blend scenario, and 2026 under the Electrification Load Balanced Blend scenario, assuming that the Millstone units retire in 2029. In the event that Millstone does not retire in 2029, the model projects that Connecticut will not need new resources until 2029 in the Base and Electrification Load Millstone Extension scenarios. Under all of the scenarios and both load cases, the model projects that Connecticut will not need new OSW specifically until the early 2030s, as stated in Objective 1.

These modeling results are not a procurement schedule, but they do provide insights for when actions may need to be taken. Near-term actions that are necessary to unlock more zero carbon renewable investment are: 1) reforming the wholesale energy markets to ensure these resources can compete, and 2) address transmission constraints through planning or procurement. With ample supply of renewable and zero carbon resources under contract, the state is not in danger of falling short of its goals while undertaking those near-term actions (2021-2022); technology prices for resources like offshore wind will

145 Redacted
146 MA DPU Docket No. 20-16/17/18, Exhibit JU-3-A, Exhibit JU-3-B
147 NYSERDA, "Launching New York's Offshore Wind Industry: Phase 1 Report", No. 19-41, Oct. 2019 (revised). Assumes COD of 2025. Contract includes capacity.
148 NYSERDA, Launching New York's Offshore Wind Industry: Phase 1 Report, No. 19-41, Oct. 2019 (revised). Contract includes capacity.
149 Docket 18-06-37 EL-2 CONFIDENTIAL
150 Docket 18-05-04 EL-74 CONFIDENTIAL
151 MA DPU Docket No. 18-76/77/78, Exhibits JU-3A, JU-3B. Procured as two phases under two separate contracts and different pricing schedules. Assumes COD of 2023.
152 MA DPU Docket No. 18-76/77/78, Exhibits JU-3A, JU-3B. Procured as two phases under two separate contracts and different pricing schedules. Assumes COD of 2023.
153 RI PUC Docket No. 4929, Schedule NG-1
154 RI PUC Docket No. 4185, Amended Power Purchase Agreement as of June 30, 2010.

likely decline further during that time, and market reforms will ensure ratepayers get full value for procured resources in the capacity market.[155] In the meantime, DEEP will monitor the numerous contingencies described in Strategy 5 to determine if additional Class I zero carbon resources are needed in 2026 or sooner (note that procurements must be held several years in advance of the desired commercial operation date for new resources).

Distributed Renewable Resource Programs

As noted above, over the last decade, the use of competitive RFPs for grid-scale renewables has enabled the State to secure quantities of new resources needed to meet the State's greenhouse gas goals at prices that have declined over time in line with falling technology costs. The State has also embraced, where possible, competitive models for programs and incentives intended to support distributed renewable generation facilities. When programs supporting distributed generation are not suitable for the competitive procurement structure because it would be administratively challenging to target the intended customer base using an annual or semi-annual procurement (i.e. residential customers), the State also relies upon administratively-determined tariffs that aim to reflect the actual cost of installing these resources, similar to the goal of the competitive procurements.

Distributed generation (DG) refers to small-scale energy resources, generally connected to the distribution system and located at or close to the end user. In addition to solar DG, fuel cells have played a significant role in Connecticut's energy policies. In addition to being RPS Class I eligible, fuel cells are supported by a variety of other programs and incentives. The LREC/ZREC program, which provides a 15-year contract for the purchase of RECs generated by smaller, distributed fuel cells, has led to 60 installed fuel cells throughout the State and an additional 14 projects in development, totaling 45 MWs. For the duration of the contracts, the LREC/ZREC program will provide an estimated $300 million in total incentives once the projects are operational. Additional fuel cell projects will be supported in the upcoming final 2 years of the LREC/ZREC program, as well as an additional 50 MW supported through the successor tariff procurements beginning in 2022. In addition, larger fuel cell installations are supported through long-term contracts resulting from grid-scale procurements. The fuel cell projects selected in DEEP's 2017/18 Best in Class procurement total 52 MW and will receive an estimated $1 billion in total contract revenue over the 20-year term. The fuel cell projects resulting from the procurement authority in Section 127 of Public Act 11-80 total 10.6 MW and will receive an estimated $323 million in total contract revenue over the 20-year term.

Distributed generation facilities include many different configurations and involve different types of electric utility customers. Currently, Connecticut offers five ratepayer-funded DG incentive programs, some of which can be paired together for a participant: net-metering and virtual net-metering (VNM), which compensate for energy produced; the LREC/ZREC and the RSIP programs, which compensate for RECs produced; and the Shared Clean Energy Facilities program (SCEF), which compensates for both energy and RECs produced (see Table 2.3). Distributed generation facilities receive federal benefits in the form of tax credits, as well as property tax exemptions, which further reduce or offset the cost of deployment.[156] Interestingly, these programs compensate somewhat similar-sized facilities at very different prices.

[155] National Renewable Energy Laboratory. Annual Technology Baseline: Offshore Wind. 2020. https://atb.nrel.gov/electricity/2020/index.php?t=ow

[156] For example, the federal investment tax credit allows a deduction from federal taxes of a certain percentage of the cost of installing renewable energy like solar. In addition, Connecticut exempts from taxation certain

Table 2.3: Connecticut Ratepayer-Funded Distributed Generation Incentive Programs

Program Participant Beneficiary	Facility Type	Energy Incentive	Environmental Attribute (RECs)
Residential customers who install Class I renewables on their premises	BTM Class I renewable facility that is less than 2 MW	Net Metering (uncapped). Average 22.5 cents/kWh incentive.[157]	Residential Solar Incentive Program (RSIP) *or* LREC/ZREC. Average 1.4 cents/kWh incentive.[158]
Commercial & industrial (C&I) customers who install Class I on their premises	Class I renewable facility that is less than 2 MW (LREC) or 1 MW (ZREC)	Net Metering (uncapped). Average 10 cents/kWh incentive for Eversource Rate 30 customers.[159]	LREC/ZREC. Average $7.12 cents/kWh incentive.[160]
Municipal, state, or agricultural customers who install a Class I/III facility on their premises ("host"), plus "benefited" accounts designated by the resource host	Class I or III renewables that are 3 MW or less	Virtual Net Metering. Average 10 cents/kWh incentive for Eversource Rate 30 customers.[161]	LREC/ZREC. Average $7.12 cents/kWh incentive.[162]
Subscribers who are electric distribution company customers	Class I renewable facility that is 4 MW or less	Shared Clean Energy Facilities (SCEF) program. Average 16.6 cents/kWh incentive from the pilot program.	

A description of each of these programs is listed in Table 2.4 below.

renewable energy used for residential purposes and authorizes municipalities to abate property taxes on certain grid-scale renewable energy projects. Conn. Gen. Stat. Sec. 12-81(57).

[157] Based on average Eversource and UI 2019 rates for residential customers.

[158] Based on $0.3785 $/watt incentive in 2019. Green Bank, Supplemental Response to CAE-11, PURA Docket No. 20-07-01.

[159] Based on average 2019 rates. DEEP recognizes there are many different rates a commercial or industrial customer could participate in through the net metering program, and Eversource's Rate 30 is included as an illustrative example.

[160] Based on average accepted 2019 bid price in the LREC/ZREC program.

[161] Based on average 2019 rates. DEEP recognizes there are many different rates a commercial or industrial customer could participate in through the net metering program, and Eversource's Rate 30 is included as an illustrative example.

[162] Based on average accepted 2019 bid price in the LREC/ZREC program.

Table 2.4: Compensation Structures for Connecticut's Distributed Generation Incentive Programs

	Customer Eligibility	Resource Eligibility	Program Cap	Compensation Structure
Energy Compensation Programs for Distributed Generation				
Net Metering	Residential	CT Class I, 2MW or less	None	(1) netting out all volumetric (kWh) charges for energy produced within a given billing month; and (2) netting out all kWh charges for energy produced in excess of monthly consumption for a 12-month banking period. Customers are compensated for any unused credits at the end of the 12-month period at the wholesale electricity rate.
Virtual Net Metering	Municipal, state, and agricultural hosts	CT Class I or III, 3MW or less	\$20 million; plus additional \$6 million for municipalities, and \$3 million for agricultural customers	(1) netting kWh generation charges and a declining percentage of transmission and distribution kWh charges for all energy produced within a given billing period; and (2) netting kWh generation charges and a declining percentage of transmission and distribution kWh charges produced in excess of monthly consumption for a 12-month banking period. Customers are compensated for unused credits at the retail electricity rate at the end of the 12-month period.
Compensation Programs for Environmental Attributes				
LREC/ZREC	All	CT low-emission Class I, 2MW or less for LREC; CT zero-emission Class I, 1MW or less for ZREC	\$8 million per year; final auction in 2021	Projects are selected through a competitive auction structure in which the EDCs select all eligible resources within the available budget, ranked based on lowest price to highest price. Projects sell their RECs to the EDCs over 15-year contracts.
RSIP	Residential	Solar PV systems	350MW	The Green Bank provides incentives to customers for installing solar PV by directly paying the contractor or system owner to reduce the homeowner's upfront costs of installation or monthly lease payments. The program receives funding from 15-year contracts, called Solar Home Renewable Energy Credits (SHRECs), for the EDCs to purchase the RECs from the Green Bank at \$5 below the ACP or the small ZREC price, whichever is lower.
SCEF	Statutorily required mix by PA 18-50, Section 7	CT Class I	25MW annually for six years; Pilot capped at 6MW	Competitive procurement selects projects and then purchases both RECs and energy from the project on a 20-year contract

Together, these programs have succeeded in supporting the deployment of an accelerating amount of distributed generation in recent years. This accelerated pace is demonstrated in Figure 2.6, which shows incremental additions to the net metering and virtual net metering program, and Figure 2.7, which shows incremental additions accepted into the LREC/ZREC program. In addition, Figure 2.7 demonstrates the success of the competitive procurement structure, as an increased number of projects are accepted into the LREC/ZREC program using the same annual budget. The LREC program also had a higher number of solar participants in 2019, increasing the MWs accepted into the LREC program. Figure 2.8 shows incremental additions accepted into the Green Bank RSIP program.

Figure 2.6: Annual Incremental Additions to Net Metering and Virtual Net Metering, 2005-2019

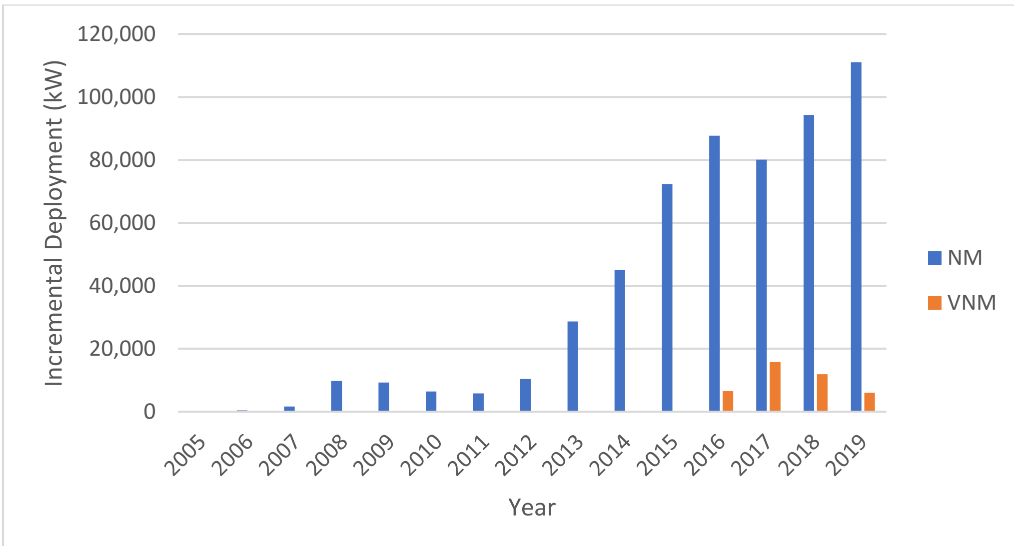


Figure 2.7: Annual Incremental Additions to LREC/ZREC, 2012-2019

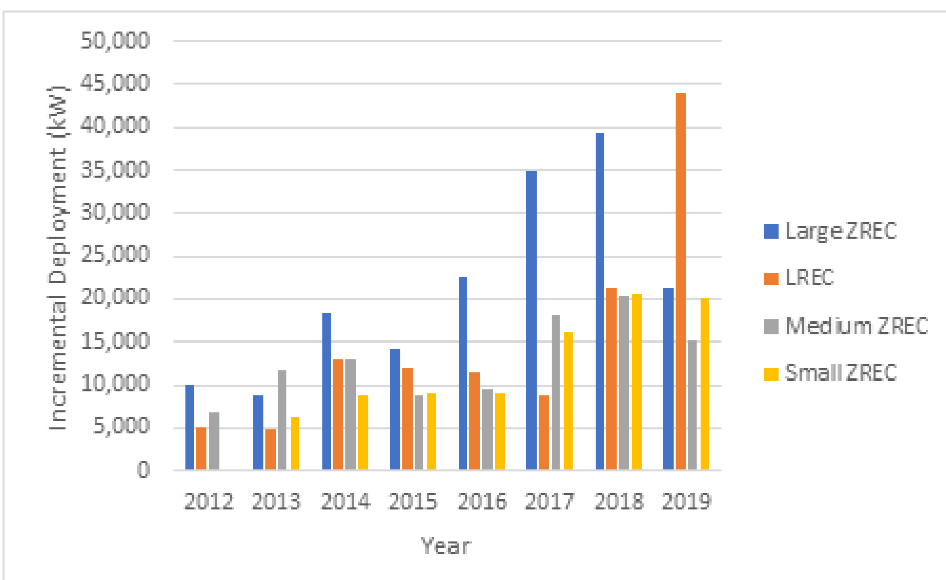


Figure 2.8: Annual Incremental Additions to Green Bank's RSIP, 2005-2019[85]

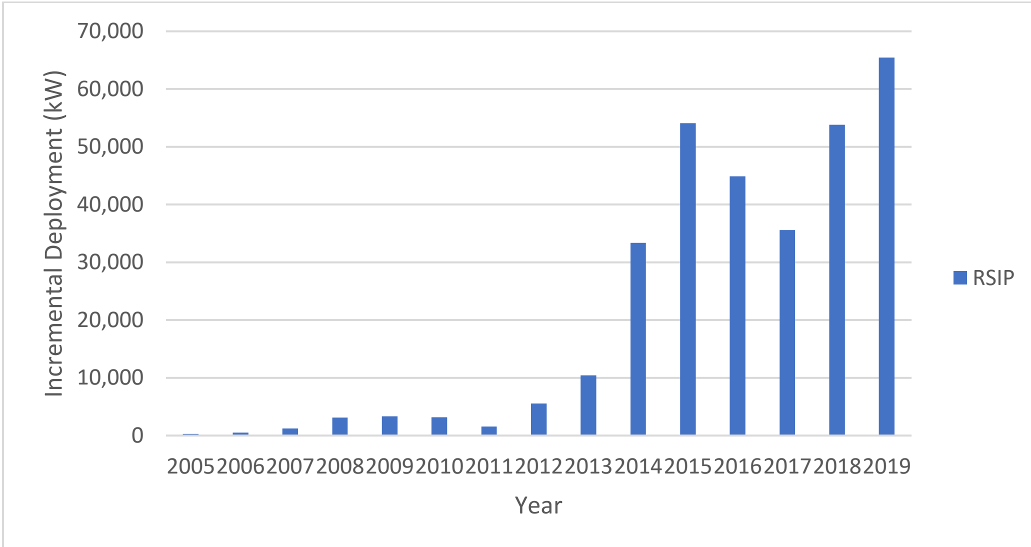


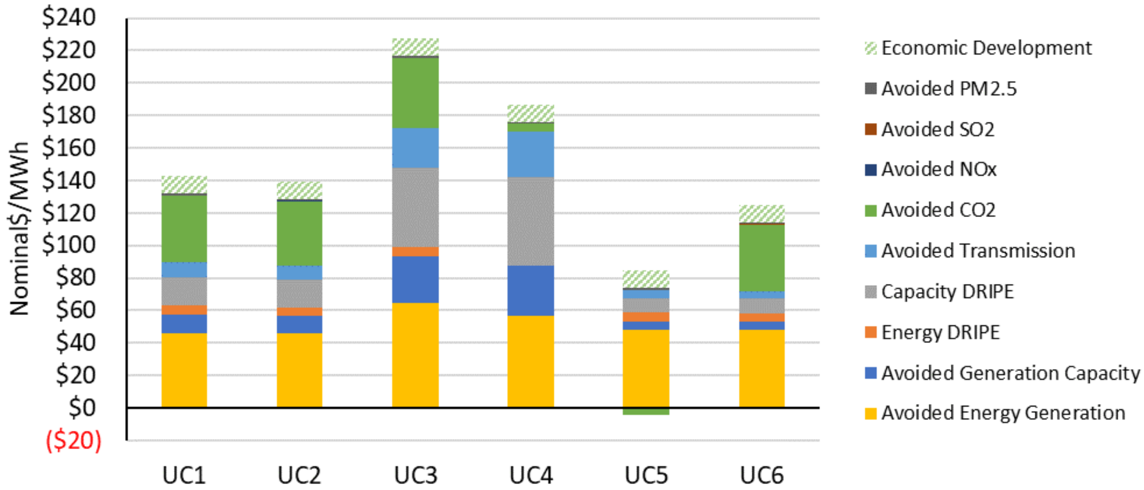
Table 2.5: Program Participation, UI and Eversource, as of July 10, 2020

Program	Cumulative Program Acceptance	Customer Participation
Net Metering	576.88 MW[163]	45,000 customers
Virtual Net Metering	86.18 MW (48.40 MW municipal, 24.7 MW agricultural, 11 MW state)[164]	84 projects
LREC/ZREC	481.81 MW[165]	2,575 projects
RSIP	340.77 MW[166]	43,025 customers
Shared Clean Energy Facility	5.22 MW[167]	3 projects

In the draft Value of Distributed Energy Resources in Connecticut (Value of DER Study), DEEP and PURA assessed the value that distributed energy resources like rooftop solar, grid-scale solar, rooftop solar paired with energy storage, standalone energy storage, fuel cells, and energy efficiency provide to the State.[168] The draft Value of DER Study attempted to quantify as many values as possible, and where explicit quantification was not possible, the study qualitatively discussed the values. The Department and PURA found the 25-year levelized, nominal values for the resources listed above were the following:

[163] Based on installed capacity
[164] Based on installed capacity
[165] Based on capacity accepted into the program
[166] Based on installed capacity
[167] Based on capacity accepted into the program
[168] DEEP and PURA, "Value of Distributed Energy Resources in Connecticut," PURA Docket No. 19-06-29, 10 (Jul. 1, 2020), available at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/56d151da9f6343af852585980063329d/$FILE/Value%20of%20DERs%20in%20Connecticut%20-%20Draft%20Study.pdf.

Figure 2.9: 25-Year Levelized Value of DER Use Cases per MWh of DER (nominal $)[169]



Note: Demand reduction induced price effects (DRIPE) refer to wholesale energy price reductions that result from energy efficiency and demand response programs.

Grid-scale solar facilities also provide some of these values, including avoided generation capacity and avoided energy generation, DRIPE, and avoided emissions. Distributed resources provide some unique benefits to the State that support investing in policy initiatives for their deployment, despite having higher costs than other zero carbon resources. For example, DG can be sited on rooftops to avoid additional development impacts in the state and support environmental and conservation goals; as such, rooftop configurations face fewer permitting, siting, and interconnection requirements and can be built faster. Distributed generation can support resilience by providing back-up generation power for critical infrastructure if the necessary islanding infrastructure is in place on the system, both in the context of microgrids and on a stand-alone basis, thereby potentially mitigating the urgency and thus the cost of restoration.

The quantified value of most DERs in the study is generally less than the compensation received through the various available incentive programs. From the perspective of ratepayers who pay the cost of these programs, it makes sense to obtain this value at the lowest price necessary. In other words, resources should be procured or incentivized at a rate sufficient to bring them to market and maximize their value. Not all values in the study were quantified and many merit further exploration, like potential electric distribution system benefits, system-siting.[170] The Department is committed to further exploration of potential siting benefits, as further set forth in Objective 4, and notes that the potential for the realization of distribution system and resilience benefits may increase as the grid is modernized and

[169] DEEP and PURA, "Value of Distributed Energy Resources in Connecticut," PURA Docket No. 19-06-29, 10 (Jul. 1, 2020). A nominal discount rate of seven percent was used. The six Use Cases (UCs) evaluated in the Value of DER Study are: UC1: Behind-the-Meter (BTM) Solar Photovoltaic (PV); UC2: Front-of-the-Meter (FTM) Solar PV; UC3: BTM Solar PV Paired with Electric Storage; UC4: FTM Electric Storage; UC5: Fuel Cell; UC6: Energy Efficiency. http://www.dpuc.state.ct.us/DOCKCURR.NSF/0/56d151da9f6343af852585980063329d/$FILE/Value%20of%20DERs%20in%20Connecticut%20-%20Draft%20Study.pdf

[170] DEEP and PURA, "Value of Distributed Energy Resources in Connecticut," PURA Docket No. 19-06-29, 74(Jul. 1, 2020). A nominal discount rate of seven percent was used.

more price-responsive rate design is implemented. Finally, diversification of the suite of zero carbon resources deployed to meet our climate goals is an important and likely unquantifiable benefit of resources like DG that warrants continued investment in deployment.

Figures 2.10 below shows the total MWhs expected to be produced by all zero carbon projects selected in DEEP's grid-scale procurements that have already been or are expected to be constructed over the next several years, as well as the State's DG programs, RSIP and LREC/ZREC. Figure 2.11 shows the annual revenue received by resources participating in those programs. While grid-scale projects produce significantly more energy than DG projects, grid-scale projects are proportionately less expensive for the same amount of energy output than DG programs, particularly the RSIP program.

Figure 2.10: Annual MWhs Expected to be Produced by Resources Participating in State Programs, as of July 10, 2020

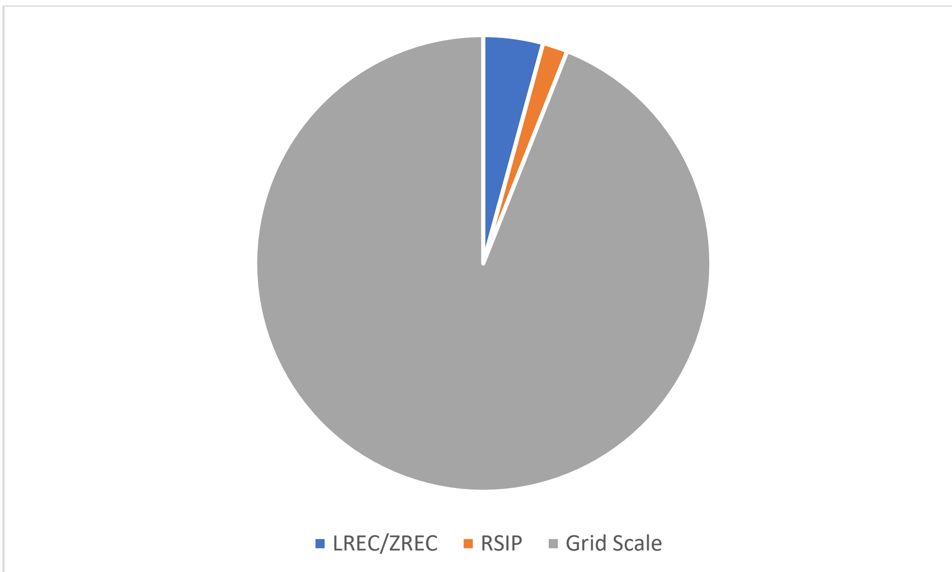
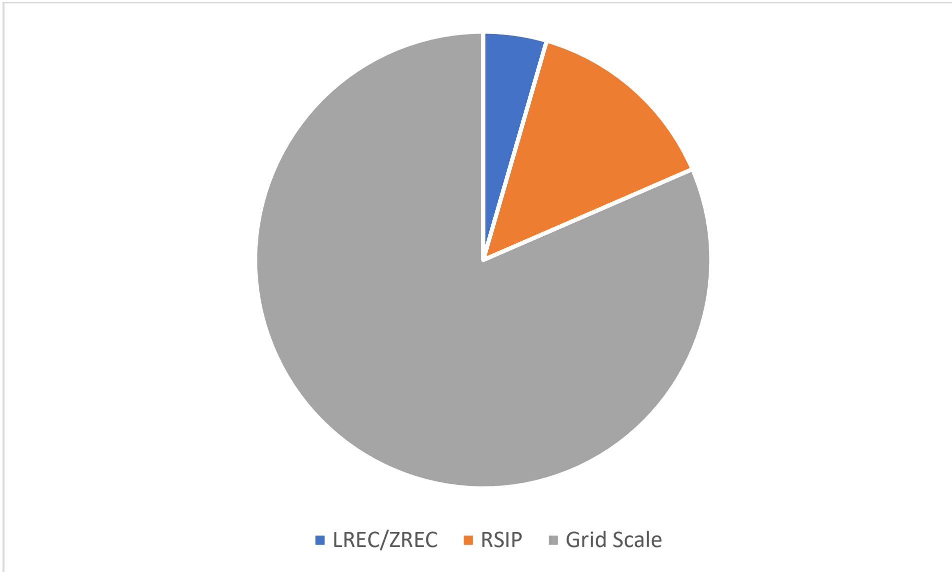


Figure 2.11: Annual Revenue Received by Resources Participating in State Programs, as of July 10, 2020[171]



The existing net metering and virtual net metering structure is tied to the retail rate for electricity, meaning the cost-effectiveness of a unit at the time of deployment depends upon a forecast of electric rates for the duration of the unit's operation. Because the retail rate changes based on the cost to the EDC of delivering power to customers and is in no way related to the distributed generation, the cost-effectiveness of a DG system can fluctuate with rate changes. For example, the 2014 Eversource rate case resulted in increased costs being recovered through demand charges rather than volumetric charges (based on kWh) for certain commercial customers, which resulted in a lesser portion of the bill that could be netted out through net metering, and thus smaller bill savings for those customers utilizing the net metering tariff.

A fixed price incentive based on a price at which the market can successfully install a unit – like that used for DEEP's grid-scale procurements – is a better incentive structure to provide revenue certainty to participants and program transparency. Competitive procurements are an effective tool for determining the fixed price the market currently needs to deploy distributed generation. This structure may not be suitable for smaller distributed generation intended to reach a large number of customers, like residential rooftop solar, because it may be too administratively complex to market to a significant number of residential customers in advance of an annual or semi-annual auction. Thus, it is more suitable to set an administrative fixed rate for these customers with the same goal of a competitive procurement, namely, to set it at a rate that ensures the unit is installed without having all ratepayers overpay for the resource. Incentive adders applied to the fixed rate could help address some of the barriers to adoption of rooftop solar for underserved and overburdened ratepayers. DEEP recommends that PURA also consider incentive adders for siting on previously disturbed land. Identified benefits to the grid could warrant additional incentives. An administrative fixed rate not only provides revenue

[171] Includes revenues received from LREC/ZREC/RSIP and net metering for distributed generation programs. Assumes all resources are online in 2019 and LREC/ZREC customers are on Eversource Rate 30 or UI Rate GC, and RSIP customers are on Eversource Rate 1 or UI Rate R.

certainty to the participant and transparency for all ratepayers, but it also allows the State to fill in any needed revenue gaps as federal tax incentives decline. Finally, it allows all ratepayers– not only renewable energy developers– to benefit from the declining costs of technologies and program efficiencies, resulting in cost savings for programs paid for by all ratepayers.

It is important to note that the BTM analysis included in Objective 1 is based upon national studies on the cost of solar and should not be interpreted to be the cost of deploying solar in Connecticut for the purposes of PURA Docket No. 20-07-01. In a sensitivity analysis, Levitan Associates, Inc. (LAI) compared the different costs to ratepayers if BTM is compensated at the national average cost of deploying the system or the residential retail rate. If BTM is compensated at the retail rate, the cost of deploying the BTM doubles. As demonstrated by Figure 1.20 in Objective 1, the successor tariff is important for creating a sustainable, least-cost compensation structure for distributed generation. This figure shows the cost of BTM systems compensated at Connecticut's current net metering rate compared to the same systems compensated at a rate based on the national cost of deploying solar, showing the former is significantly more expensive than the latter. As the State attempts to address climate change and maintain affordable electric rates, PURA must carefully balance finding a rate for the successor program that achieves continued deployment at competitive rates.

Issues Affecting Connecticut's Renewable Portfolio Standard

Disposition of Contracted Renewable Energy Credits

For any RECs purchased resulting from DEEP's grid-scale procurements, the EDCs may either retain or resell those certificates, whichever is in the best interest of ratepayers.[172] Currently, the EDCs purchase the RECs and resell them into the market. This means that Connecticut ratepayers are providing the financial support needed to bring these renewable and zero carbon resources online but cannot necessarily take credit for their production from an emissions accounting perspective because the associated environmental attributes may be sold outside of Connecticut.[173]

One of the primary objectives of the RPS and various programs is to incentivize the development of zero carbon and renewable energy is to help the State achieve its greenhouse gas reduction goals as articulated in the GWSA. It is therefore reasonable that the State take full credit for all the programs ratepayers are supporting in the State's carbon accounting. Connecticut General Statutes Section 22a-200a(a)(4) requires the DEEP Commissioner to establish the accounting to measure compliance with the statutory greenhouse gas reductions. The Department's current greenhouse gas inventory is consumption-based and attributes Connecticut's load share of regional emissions accounting for imports, line losses, and pumped storage. The greenhouse gas accounting to date has not been linked to the RECs retired by electric suppliers in Connecticut in compliance with the RPS or the RECs purchased by the EDCs pursuant to the several programs discussed above supporting renewable and zero carbon generation.

[172] Conn. Gen. Stat. Secs. 16a-3f, 16a-3g, 16a-3h, and 16a-3 j; Public Act 19-71.

[173] Even RECs that are ultimately sold to an energy supplier serving Connecticut creates an inefficiency as the EDCs procure the RECs through a contract and then sell the RECs to an energy supplier in Connecticut for RPS compliance often going through a broker. This system creates several inefficiencies and middlemen, unnecessarily increasing costs to ratepayers.

The most recent greenhouse gas emissions inventory is from 2017.[174] The existing inventory structure is different from the accounting method used in this IRP, as discussed in Objective 1, and DEEP is currently revising it, as discussed in Strategy 7. Relatedly, this IRP recommends an investigation into whether it is in the best interest of ratepayers to retain RECs and environmental attributes purchased through energy policy programs like DEEP grid-scale procurements and DG programs.[175]

The revenues earned from reselling the RECs in energy policy programs (e.g. RSIP, LREC/ZREC, etc.) are used to offset the total cost of the contract, which lowers the net contract cost paid for by all ratepayers when it appears as a line item in the federally mandated congestion charge (FMCC).[176] While the revenue received from the sale of the RECs helps to lower the cost of individual contracts themselves, it is not clear whether this practice of REC sales is resulting in least-cost RPS compliance for ratepayers overall. For example, there are administrative costs (e.g. transaction costs and risks) to selling RECs in the wholesale market through one program only to have suppliers purchase RECs for retail-level compliance with the RPS. In determining whether it is in the best interest of ratepayers to retain or resell the RECs, it is important to look at the costs incurred and revenues earned from grid-scale procurement RECs compared to the costs incurred by LSEs to purchase a similar amount and type of RECs. The Department understands there are administrative complexities to implementing this change, but believes the benefits in achieving our statewide climate goals and potential for cost savings warrant further investigation.

Impact of BTM Resources on RPS Compliance Obligation

Connecticut's RPS requirement is based on a percentage of the load that is settled through the ISO-NE wholesale market. Connecticut's RPS applies to load net of all of the BTM resources (as well as municipal electric utilities, which are exempt from RPS requirements) and energy efficiency. Behind-the-meter solar PV and BTM fuel cells are also Class I REC eligible, producing RECs that are counted towards RPS compliance. Thus, these resources are accounted for twice: once as a load reducer and once as a generator through the production of RECs. This "double count" effectively reduces Connecticut's annual RPS percentage because as BTM resources reduce the total load for the state, it coincidentally reduces how many RECs must be purchased by load serving entities; the impact of which is illustrated in Figure 2.13.

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[174] DEEP relies on data from the EPA in developing its greenhouse gas emissions inventory, and 2017 is the most recent year this data is available. The 2017 and prior reports can be found on the DEEP website at https://portal.ct.gov/DEEP/Climate-Change/CT-Greenhouse-Gas-Inventory-Reports

[175] PURA will explore this issue as part of its investigation on the building blocks of resource adequacy and clean electric supply in Docket No. 17-12-03RE10, set to be opened following the issuance of this IRP. *See* Final Decision, Docket No. 20-01-01, *Administrative Review of the Connecticut Light & Power Company's Standard Service and Supplier of Last Resort Service 2020 Procurement Results and Rates*, at p. 14 (Dec. 2, 2020).

[176] *See* PURA Docket Nos. 20-03-01 and 20-03-02. See responses to interrogatories from DEEP to Eversource, available at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/40161584f298b1b0852585a40062a0b4?OpenDocument; and responses to interrogatories from DEEP to United Illuminating at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/1b16844f6054979f852585a0004e078e?OpenDocument

Figure 2.13: Connecticut Class I RPS Demand and Demand Net of BTM Resources

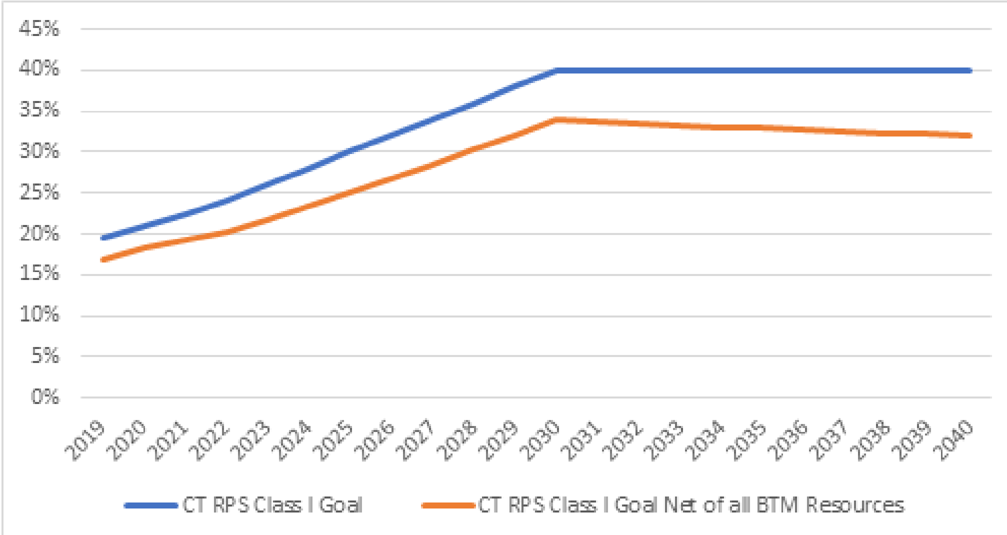


Figure 2.13 demonstrates how the impact of "double counting" BTM resources is not trivial. In 2029, counting BTM resources as both a load reducer and a Class I resource effectively causes Connecticut's projected Class I RPS requirement to be reduced from 40 percent to 33 percent. This reduced percentage is equivalent to more than 450 MWs of offshore wind that could have been supported.[177]

Strategies to Achieve Objective 2

Deregulation was perceived as a solution that would secure competitive, low cost generation, and reduce risk to ratepayers. Instead, over the last two decades the markets established to support deregulation have caused Connecticut to forfeit its self-supply rights and authority to determine the resource mix serving its citizens. Additionally, the markets administered by ISO-NE have forced the region into over-reliance on natural gas resources while struggling to maintain reliability goals, instead falling back on expensive RMR contracts and, in the case of Millstone, Connecticut's ratepayers to support an out of market contract to prevent possible rolling blackouts impacting the region during a winter peak event. ISO-NE has not been receptive to past efforts by the states to bring resolution to these issues. At this point, and in order to meet the 100% Zero Carbon Target as efficiently as possible, the markets must be reformed. This IRP recommends pursuing the following strategies in furtherance of Objective 2, Securing the Benefits of Competition & Minimizing Ratepayer Risks. These strategies are further explained in Section II.

At the regional level, Connecticut must pursue reforms of the New England wholesale electricity markets to resolve the issues discussed above in this Objective (Strategy 2). This will also include reforms to the governance structure of these markets to make them more inclusive and sustainable (Strategy 3). As mentioned, any resulting changes from Strategy 2 and 3 will need to be closely monitored to determine their impact on the need for new grid-scale procurements to meet the 100% Zero Carbon Target (Strategy 5). While working to achieve market reform, Connecticut will coordinate

[177] Assumes a 54 percent capacity factor.

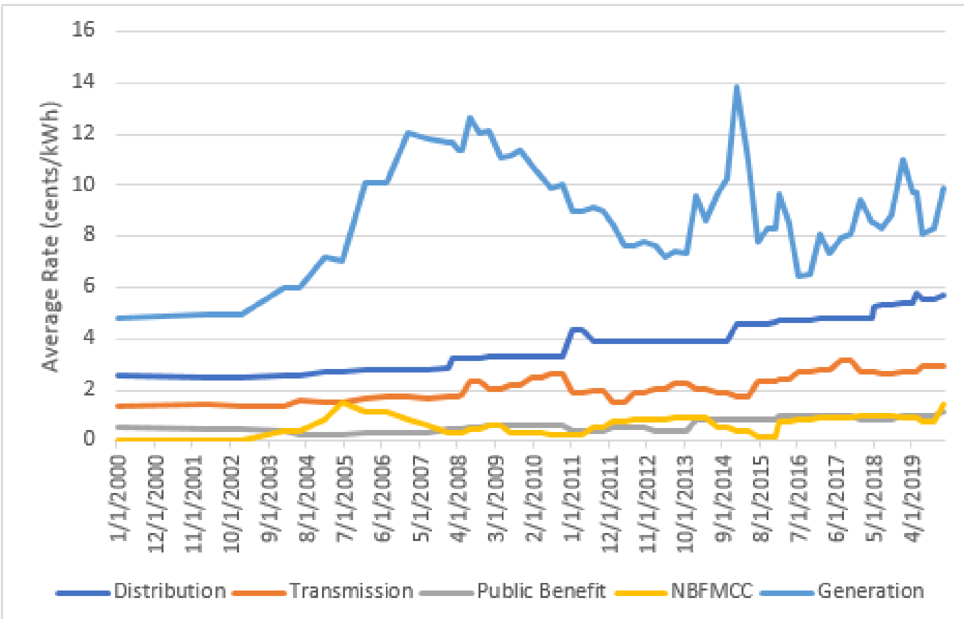
with the other New England states on evaluating transmission needs to meet state climate and energy policy goals and determine if the FERC Order 1000 public policy transmission planning process, or an alternative, is needed in the near future (Strategy 4).

Enhancing competition of the clean energy markets to secure the benefits of lower costs or enhanced value for ratepayers will require Connecticut to update certain aspects of its own state-jurisdictional programs. For distributed generation programs, Connecticut should structure the successor tariff programs to achieve historic deployment levels and equitably distribute the benefits of zero carbon generation (Strategy 6). This IRP also recommends addressing issues around compliance with Connecticut's RPS, including determining if having the EDCs retain RECS is in the best interest of ratepayers (Strategy 7), and addressing the impact behind-the-meter resources have on reducing overall RPS compliance obligations (Strategy 8). These actions will help increase competition and maximize the benefits the RPS can provide to ratepayers.

Objective 3: Ensuring Energy Affordability and Equity for all Ratepayers

In recent years there has been upward pressure on Connecticut's electric rates. There are several contributing factors to this. Figure 3.1 below shows the various components of the standard electric bill. Those components relevant to energy supply (the focus of this IRP) are further discussed below.

Figure 3.1: Historical Rate Composition in Connecticut, 2000-2019



Impacts on Generation Affordability

This IRP focuses on those portions of the electric bill that relate to affordable electricity supply. The Generation rate component reflects an average of the retail price of electricity (i.e., Standard Service) supplied through the ISO-New England wholesale markets, or the full "requirements" that load-serving entities must include in supply offers to retail customers. The Generation rate includes the cost of the ISO-NE energy, capacity, and ancillary services markets, as well as the costs of RMRs and other mechanisms the ISO-NE has implemented in response to fuel security challenges and exercises of market power. The Generation rate also includes the cost of procuring Renewable Energy Certificates to meet the annual required percentage in compliance with the state's Renewable Portfolio Standard.

Retail rates for Generation have experienced volatile fluctuations in recent years, reflecting the sensitivity (discussed in Objective 2) of ISO-NE's natural gas-dependent electric market to changes in the availability and commodity prices for natural gas fuel. The highly volatile generation charge reflected in Figure 3.1 is the result of an electric system highly dependent upon natural gas powered generation in a region that does not have the infrastructure to support that level of natural gas generation in the winter during very cold weather events. As noted in Objective 2, ISO-NE's response to the over reliance on natural gas has not been to try to create a market that encourages a diversity of resources, especially clean and renewable energy, but to prop up aging oil units and to actually discourage renewable generation through the MOPR. The state's investments in energy efficiency and renewable energy have helped to reduce the need for new power generation and mitigated to some extent the region's overdependence on natural gas, including by lowering capacity costs.

The regional markets have also failed to modernize and fully take advantage of distributed resources and non-wires alternatives, instead always responding to a system need by building more decentralized generation and new transmission wires. Thus, as Connecticut ratepayers are paying the full costs of investments consistent with state policies and a modern grid, they are also forced to pay their load share costs of the ineffectual ad-hoc regional market. The deregulated markets entered into by Connecticut policy makers to reduce costs and encourage innovation are actually having the opposite effect of increasing costs and stifling innovation.

In order to counter these systemic failures, Connecticut ratepayers have been forced to step in by entering into contracts with peaking and renewable generation that are recoverable through the non-bypassable federally mandated congestion charge (NBFMCC). The NBFMCC includes an array of different costs, some of which include the net costs of ratepayer-backed energy and REC purchase contracts that the state has entered into to ensure deployment of new renewable resources and more recently, prevent the retirement of the Millstone nuclear facility. In addition, investments in energy efficiency are supported largely through the Systems Benefit Charge (see Public Benefit, Figure 3.1). Removing the barriers to public policy resources in the ISO-New England markets, and achieving reform of the wholesale markets, as detailed in Objective 2, is a key strategy to improving the affordability of Generation supply, by reducing price volatility and costly RMRs associated with natural gas dependence, eliminating duplicative and inefficient costs associated with having to pursue clean energy objectives through separate markets, and seeking more equitable distribution of the costs of resources like Millstone that provide regional reliability and emission reduction benefits.

Impacts on Transmission Affordability

Competition is needed to cost-effectively meet our transmission needs. Over the last twenty years, there has been significant investment in transmission infrastructure in New England.[178] Regional returns on equity (ROEs) allowed by FERC in transmission rate proceedings are not only unacceptably high, they are moving higher and need to be addressed.[179] Transmission charges in New England rose from approximately $869.00 million in 2008 to $2.25 billion ten years later. The current $2.25 billion/year in network load costs represent 20 percent of total wholesale energy costs.[180] The result of this significant investment is a regional transmission system that is *currently* essentially congestion-free.[181]

However, this has come at considerable expense; transmission service costs in ISO-NE are more than double the average rates in any other RTO/ISO in the country.[182] In fact, New England is now ranked near the top nationally in load-weighted spending on transmission construction but New England ranks near the bottom in terms of circuit-miles built per megawatt-hour of load and circuit-miles per million dollars spent. In short, New England spends more on transmission and get less built then almost any

[178] ISO-NE, 2020 Regional Electricity Outlook, p. 11.
[179] "Return on Equity" refers to the earnings electric utilities are allowed to earn on investments in transmission upgrades.
[180] ISO-NE Internal Market Monitor Quarterly Performance Report, Spring 2020, page 20.
[181] ISO-NE, 2020 Regional Electricity Outlook, p. 11.
[182] Potomac Economics, Highlights of the 2019 Assessment of the ISO-NE Markets, June 2020, page

other region of the country.[183] At least one reason for this is likely because, unlike other RTOs/ISOs, ISO-NE lags considerably in encouraging competition in developing transmission projects. In fact, while FERC Order 1000 expressly encouraged RTOs/ISOs to encourage competition in transmission planning, unique among RTOs/ISOs, ISO-NE has only now just completed its first competitive transmission procurement.[184] Studies have shown that cost savings on average of 20 percent to 30 percent can be expected if transmission development is open to competition.[185]

Therefore, it will be necessary that transmission planning going forward begin with a clear evaluation of how to maximize the use of the existing transmission system. In this regard, well-planned deployment of energy efficiency measures and BTM solar can obviate the need for expensive upgrades. Dynamic line ratings and system optimization software and other measures can effectively and measurably improve the efficient use of existing power lines. Only once that careful study has shown that new or upgraded transmission elements are truly needed will system planners and state officials proceed to the next step of developing new transmission projects

Connecticut's Energy Affordability Gap

According to Operation Fuel's 2017 report "Home Energy Affordability in Connecticut: The Affordability Gap," Connecticut faces a significant gap in residential energy affordability, which is defined as the dollar amount by which home energy bills exceed what home energy bills would be if they were equal to an affordable percentage of income.[186] The Home Energy Affordability Gap model considers a bill "affordable" if it does not exceed six percent of annual household income. Connecticut's high electric rates result in correspondingly high household energy prices, which place a disproportionate and inequitable burden on low-income families. This burden is exacerbated by the aging, energy inefficient housing stock in the state. Approximately 30 percent of people seeking weatherization measures for their homes through the Home Energy Solutions Income Eligible Program (HES-IE), which serves those whose gross income does not exceed 60 percent of the state median income, cannot weatherize their homes due to health and safety barriers to the necessary interventions.[187] These barriers to weatherization prevent people from increasing their energy efficiency and it increases their energy bill. The average annual difference between actual and affordable home energy bills for households at or below 200 percent of Federal Poverty Level (FPL) was $1,404 per household in 2017. The aggregate Home Energy Affordability Gap ("Affordability Gap") in Connecticut was more than $450 million statewide in 2017.[188] The population of households facing this Affordability Gap is substantial. According to the American Community Survey, Connecticut had roughly 320,000 households with income at or below 200 percent of the FPL.[189]

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[183] Dept. of Energy 2017 Transmission Metrics Report at pp. 40-50
[184] ISO-NE, 2020 Regional Electricity Outlook, p. 31.
[185] The Brattle Group, Cost Savings Offered by Competition in Electric Transmission, April 2019, at 10.
[186] Operation Fuel. "Home Energy Affordability in Connecticut: The Affordability Gap (2017). October 2017. Available at: https://operationfuel.org/wp-content/uploads/2017/12/2017-ConnecticutHEAG-11-27-17-RDC-edits.pdf
[187] Eversource. "Eversource Barrier Report," presented at the Energy Efficiency Board Residential Committee Meeting. July 8, 2020. https://app.box.com/s/ofikmpd7r7ubvwbwnyi98d39y8he19bk/file/688801991554
[188] *Id*.
[189] *Id*.

Private and public support services are not able to adequately address this Affordability Gap. The principle source of energy assistance in Connecticut is the federal Low-Income Home Energy Assistance Program (LIHEAP). LIHEAP continues to cover only a fraction of the Home Energy Affordability Gap for a fraction of income-eligible households. Connecticut's LIHEAP allocation for the 2016-2017 heating season was only $78.7 million, roughly 17.5 percent of the total Affordability Gap in the state for 2017.[190]

In addition, businesses face energy affordability issues in Connecticut. High electric rates impact small businesses that often face barriers to engaging in energy savings measures such as efficiency and solar PV, especially if they rent their space. Energy costs also impact business decisions by manufacturers and other large commercial and industrial customers that use large quantities of energy.[191]

The affordability gap and the impacts from energy costs on economic development have been significantly exacerbated by the COVID-19 pandemic beginning in early 2020. As the virus spread, businesses were forced to shut down operations, causing thousands of Connecticut citizens to lose employment both temporarily and permanently. That impact is demonstrated by the levels of arrearages, or unpaid customer balances, the EDCs are currently carrying. This acute, recent trend highlights the need to emphasize affordable strategies in this IRP for meeting the state's electricity supply. PURA Docket 20-01-33 revealed that from 2015-2019 on average, UI has had between $20 and $30 million in "uncollectible" arrearages,[192] and Eversource has approximately $60 million.[193] By contrast, as of October 31, 2020, Eversource had arrearages of more than 30 days totaling nearly $265 million, almost $176 million of which was more than 120 days overdue.[194] Despite having far fewer customers, UI had arrearages of more than 30 days totaling nearly $232.5 million, the vast majority of which was more than 120 days overdue.[195]

Energy Equity

Throughout this IRP, in addition to focusing on affordability, DEEP addresses access to and participation in Connecticut's energy policy programs by underserved and overburdened communities, consistent with the direction from Governor Lamont in Executive Order 3 that the GC3 analyze climate mitigation and adaptation progress through an equity lens. The GC3 Equity and Environmental Justice (EEJ) Working Group was charged with developing a plan and guidelines for engaging diverse stakeholders and coordinating with other working groups to evaluate recommended strategies. This important process is currently underway. The Department is committed to ongoing engagement and coordination with the EEJ Working Group and will leverage the outcome of that process to ensure that future energy planning processes and energy policies center equity, diversity, and inclusion. The Department will focus

[190] *Id*.
[191] As of August 2020, Connecticut's commercial electricity rates were lower only than California, Alaska and Hawaii
[192] *See* PURA Docket No. 20-03-33, *PURA Review of Electric Distribution Companies' Method of Payment to Licensed Electric Suppliers for Uncollectible Customer Accounts,* UI Interrogatory Response EOE-001, March 19, 2020
[193] *See* PURA Docket No. 20-01-33, *PURA Review of Electric Distribution Companies' Method of Payment to Licensed Electric Suppliers for Uncollectible Customer Accounts,* Eversource Interrogatory Response EOE-001, March 19, 2020
[194] *See* PURA Docket No. 18-04-25, *PURA Investigation Regarding Issues Related to Uncollectible Accounts (Uncollectibles Investigation)*, Eversource Compliance Filing, Nov. 16, 2020.
[195] *See* PURA Docket No. 18-04-24, *PURA Investigation Regarding Issues Related to Uncollectible Accounts (Uncollectibles Investigation),* UI Compliance Filing, Nov. 13, 2020.

on near-term strategies to promote energy equity and will continue to be guided by energy equity as it develops additional strategies in futures IRPs and other planning documents.

Strategies to Achieve Objective 3

In the pursuit of an equitable, zero carbon grid of the future, prioritizing affordability is paramount. Therefore, this IRP recommends pursuing the following Strategies in furtherance of Objective 3, Ensuring Energy Affordability and Equity for all Ratepayers. As discussed in Objectives 1 and 2, reform of the wholesale electricity markets is necessary so that Connecticut ratepayers do not have to pay twice for electric generation (Strategy 2), including clean energy supply needed to meet the state's decarbonization goals and mandates. Additionally, an investigation of whether retaining RECs obtained by the EDCs on behalf of all ratepayers to meet RPS requirements is in ratepayers' best interests should be conducted (Strategy 7).

Customer costs can also be reduced through further deployment of cost-effective energy efficiency and demand response measures through the C&LM program (Strategy 12) and developing opportunities for ratepayers to actively participate in New England's energy sector through active demand response and energy storage (Strategy 13). These tools can also help decrease the overall cost of electricity in Connecticut, while increasing the reliability of the grid. The Department is currently engaging stakeholders in an Equitable Energy Efficiency Proceeding to ensure the equitable distribution of energy efficiency benefits to customers who have been underserved and overburdened, and to develop metrics to track equitable distribution in a more meaningful way going forward.

Equity also requires structuring the successor tariff supporting distributed generation such that all ratepayers can equitably access and participate in these programs, including residential rooftop solar (Strategy 6). The successor tariffs should be structured in a way that ensures that at least 40 percent of residential solar deployments are occurring in low income households and in low- to moderate-income households in environmental justice communities. The Department also recommends increasing the low-income and low- to moderate-income subscribership requirements under the SCEF program structure, working towards a 100 percent low- to moderate-income subscribership goal.

The transition to a clean energy economy provides significant economic opportunity to our residents, businesses, and communities. The Department will coordinate with DECD and its Office of Workforce Strategy, and other stakeholders, to ensure that clean energy economic and workforce development is conducted in an equitable and inclusive manner (Strategy 9).

Objective 4: Optimal Siting of Generation Resources

Another key question to be evaluated in the IRP, as required by Section 16a-3a(d) of the General Statutes, is whether the use of generation sites in Connecticut is optimal. This section addresses historical trends and current issues related to siting of both conventional, fossil-fueled generation in the state, as well as renewable generation.

Siting of Large Fossil-Fueled Power Generation in Connecticut

Connecticut has, for many years, been an attractive location for the development of fossil fuel-powered generation facilities in New England. Although Connecticut has no economically recoverable coal, oil, or gas, coastal and inland waterways as well as rail networks have provided convenient delivery points for those fuels to power generation sites along the shoreline and adjacent to navigable rivers. Hundreds of miles of high-voltage transmission lines were constructed across the state, making it possible for Connecticut-generated power to reach load centers in Connecticut, Massachusetts, and Rhode Island. In addition, three interstate natural gas pipelines cross Connecticut support essentially all of the region's natural gas fired generation. Further, since 2017, stricter environmental regulations in a neighboring state—namely, an in-state cap on carbon emissions from power plants that Massachusetts applies within its borders—have also contributed to making Connecticut a comparably lower-cost location for operating new and existing fossil-fueled generation.

Prior to deregulation, Connecticut was a net importer of power generation, producing less energy in-state than it consumed.[196] In 1996, Connecticut had 39 fossil fuel-powered generating units operating in the state, generating over nine million MWh of electricity as well as more than 11,176 tons of NOx, and 9 million short tons of CO_2 emissions.[197] Over 57 percent of the electricity generated by this fossil-fueled fleet was produced with oil; 26 percent with coal, and 10 percent with pipeline natural gas.[198]

In the years following deregulation, the current basic structure of the market rules in New England took shape through the adoption of a new Market Rule 1 (MR1) in 2002. One of the most challenging issues MR1 addressed was mitigating market power in regions that were transmission constrained. In areas that were constrained, units had the ability to exercise market power as the region could not operate reliably without the units located within the zone. On the other side of that coin, peaking units that were necessary in only a few hours of the year were at risk of not being able to profitably operate. Accordingly, MR1 allowed for Reliability Must-Run (RMR) contracts. FERC, over Connecticut's objections, adopted ISO-NE's position that RMR contract costs were to be paid only by the ratepayers in the congested area. Thus, soon after MR1 went into effect, several plants located in Southwest Connecticut entered into RMR contracts with ISO-NE, the costs of which were borne entirely by Connecticut ratepayers.

In order to help alleviate the risk of high costs to Connecticut ratepayers due to constraints in southwest Connecticut, the General Assembly enacted Connecticut General Statutes §§ 16-243m and 16-243u to allow State regulators to procure generation. As a result, Connecticut's EDCs entered into contracts for

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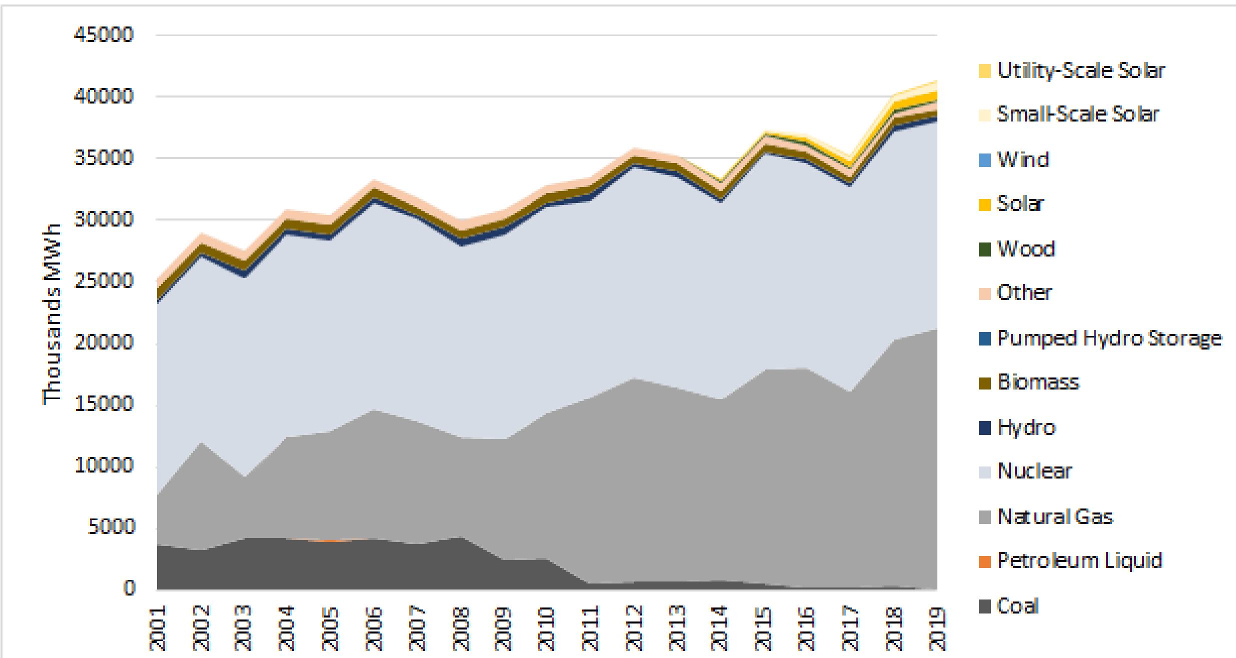
196 ISO New England, https://www.iso-ne.com/static-assets/documents/2020/09/gen_nel_iso_states.xlsx
197 U.S. Environmental Protection Agency. Air Markets Program Data. https://ampd.epa.gov/ampd/
198 U.S. Energy Information Administration. Historic form EIA-906 Detailed Data with previous form data (EIA-759). https://www.eia.gov/electricity/data/eia923/eia906u.php

peaking capacity and base load throughout the state. It is important to note that at the time the EDCs were entering into the contracts, new capacity was not being constructed without long-term contracts. That is, the market rules did not provide sufficient confidence to investors to put forward the capital necessary to develop a project. However, after Connecticut entered into those contracts, ISO-NE amended the market rules to be more favorable to new generation.[199]

Since that market rule change, the FCM has incentivized investment in new resources to replace retiring resources and growing peak demand. The markets' ostensibly fuel-neutral design has primarily incentivized the development of natural gas-powered generation, which have increasingly out-competed oil- and coal-powered plants, as discussed in Objective 2. Following RGGI's inception in 2008, the relative efficiency of natural gas was further highlighted as generation from oil and coal declined even more, as shown by Figure 4.1 below.

Figure 4.1: Annual Connecticut Net Generation by Fuel Type[200]



Today, Connecticut is a net exporter of power generation, consuming only 73 percent of the electricity generated in the state.[201] There are 54 large fossil fuel-powered generating units operating in Connecticut, comprising 6,937 MW of aggregate capacity—more than double the fossil-fueled capacity in operation in 1996. These units produce about 98 percent of the electricity generated from fossil fuels in the state, generating 16,948,025 MWh of electricity, and eight million short tons of CO_2 emissions in

[199] See 154 FERC ¶ 61005
[200] U.S. Energy Information Administration. Available at https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2
[201] ISO New England, https://www.iso-ne.com/static-assets/documents/2020/09/gen_nel_iso_states.xlsx

2019.[202] The Killingly Energy Center natural gas power plant proposed by NTE Energy in Killingly, CT would add an additional 650 MW of capacity in 2022.

Seven of these generating units (1,965 MW in aggregate) were constructed in the 1960s or earlier and have the worst air pollution emission rates per unit of electricity produced of the entire fleet. One of the seven is the Bridgeport Harbor Station Unit 3, the state's last coal-fired power plant, which is scheduled to shut down permanently in July 2021. Most of these older units run on residual oil, and their technology is so inefficient and costly to operate that they run infrequently, producing less than 1.8 percent of the electricity, yet 3 percent of the CO_2 emissions and 28 percent of the NOx emissions in Connecticut's large fossil-fuel generating fleet. These units receive revenue streams through the ISO-NE capacity market. There does not seem to be evidence that the Pay for Performance (PFP) program instituted by ISO-NE is impacting the retirement decisions of resources, as the region has seen minimal retirements since PFP has been in place.[203] This trend may change as the PFP penalties increase.

More than 40 fossil-fuel powered generating units have been constructed in Connecticut since 1998 (4,738 MW total). While several were built through ratepayer-backed contracts to alleviate costly transmission constraints, as described above,[204] another 1,900 MW[205] have cleared in the capacity market without a contract, funded exclusively through the ISO-NE regional tariffs to meet resource adequacy requirements for the entire region. Twelve of these units are "baseload" combined cycle units, which are designed to run constantly and are powered primarily by pipeline natural gas, with diesel oil in onsite storage as a back-up fuel. In 2019, these twelve units produced 16,484,295 MWh, or 98 percent, of the total amount of power generated from large fossil-fuel fired power plants in Connecticut; as well as 96 percent of the total CO_2 emissions; and 67 percent of total the NOx emissions from those plants.

Table 4.1: Connecticut In-State Baseload Combined Cycle Units

Facility Name (*denotes location in an environmental justice community)	Primary/Secondary Fuel	MWh Produced (2019)	% of Total MWh	CO2 Emitted (2019, short tons)	% of Total CO2 emitted
CPV Towantic Unit 1	Pipeline Natural Gas (PNG)/Diesel Oil	2,525,074	15%	1,002,134	12%
Milford Power Unit 1	PNG/Diesel Oil	1,936,384	11	805,288	10
Milford Power Unit 2	PNG/Diesel Oil	1,870,688	11	761,206	9
CPV Towantic Unit 2	PNG/Diesel Oil	1,439,558	8	569,207	7
Lake Road Unit 2*	PNG/Diesel Oil	1,185,656	7	775,964	10
Lake Road Unit 1*	PNG/Diesel Oil	1,176,089	7	803,379	10

[202] The 800 tons of NOx represent 23 percent of Connecticut's annual electric sector emissions, and 2 percent of statewide total NOx emissions, which are dominated by transportation-produced emissions at approximately 31,000 tons per year.

[203] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-fcm-pay-for-performance-pfp-rule

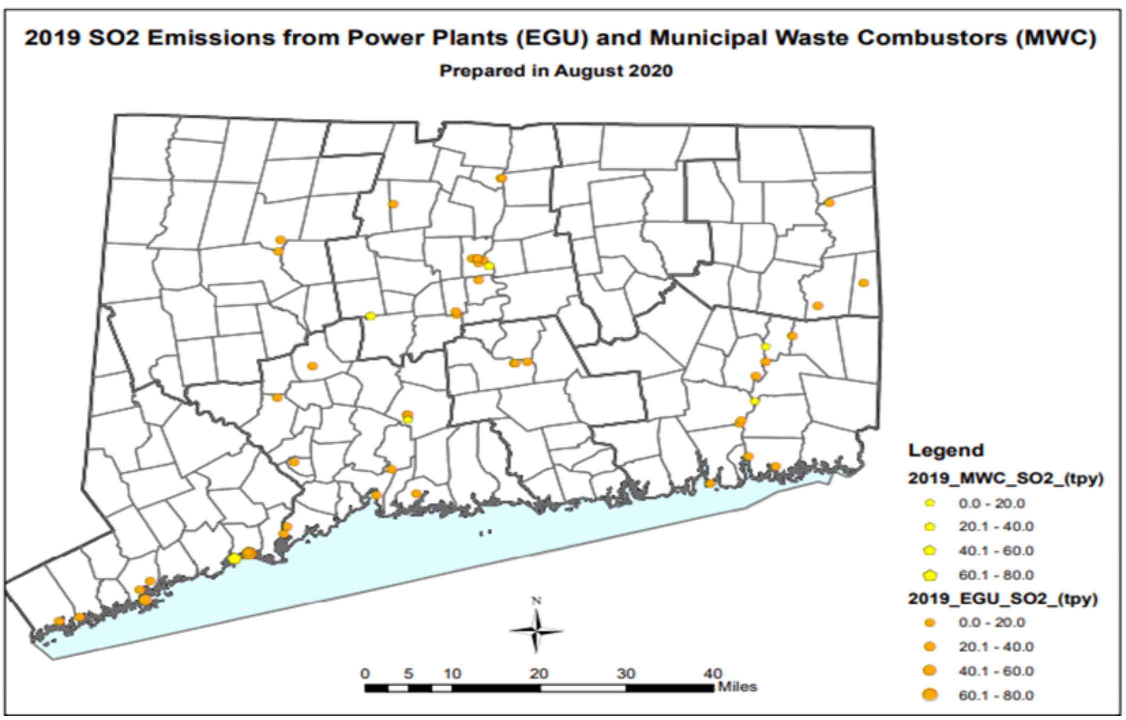
[204] *See* Docket No. 05-07-14PH02, DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges (Long Term Measures) (Approving 782 MW of new fossil fuel generation plants and 5 MW of energy efficiency); 08-01-01, DPUC Review of Peaking Generation Projects (Approving contracts of 678 MW of new fossil based peaking generation)

[205] 1,300 MW have already been constructed. 650 MW have cleared the market but has not yet been constructed.

Kleen Unit 1	PNG/Diesel Oil	1,151,759	7	481,846	6
Bridgeport Energy 2*	PNG	1,139,273	7	504,831	6
Bridgeport Energy 1*	PNG	1,109,638	7	514,472	6
Lake Road Unit 3*	PNG/Diesel Oil	1,048,211	6	723,826	9
Kleen Unit 2	PNG/Diesel Oil	1,026,879	6	432,886	5
Bridgeport Harbor 5*	PNG/Diesel Oil	875,086	5	338,463	4

Under the Base Load Balanced Blend scenario, annual CO_2 emissions across New England are projected to be cut nearly in half by 2040, with emissions offset by additional zero carbon energy purchases. SO_2 emissions in Connecticut are projected to decline by 10 percent, or 130 short tons, by 2040, with the majority of those emissions coming from WTE facilities. NO_X emissions in Connecticut are projected to decline by 25 percent, or 1,500 short tons, by 2040, again mostly coming from WTE facilities. Environmental justice communities, as defined by CGS Section 22a-20a, bear the disproportionate burden of air pollution from these large fossil power plants, as demonstrated by Figure 4.2 and Table 4.2 below.[206] Twenty-three of the state's large fossil fuel generating units are located in environmental justice communities, emitting more than 372 tons of NOx (greater than 46 percent of the NOx from the fossil-fueled power generation) annually. Some of these communities also host WTE facilities, which generate electricity from burning municipal solid waste (MSW) rather than fossil fuels and produce significant quantities of air pollution as well.

Figure 4.2: 2019 Location and SO_2 Emissions from Combustion Plants in Connecticut[207]



[206] "Environmental justice community" means (A) a United States census block group, as determined in accordance with the most recent United States census, for which thirty per cent or more of the population consists of low income persons who are not institutionalized and have an income below two hundred per cent of the federal poverty level, or (B) a distressed municipality, as defined in subsection (b) of section 32-9p; C.G.S 22a-20a(a)(1)
[207] Connecticut DEEP. Connecticut's Emissions Reductions through 2019. 2020

Table 4.2: Peak Demand Generators Located in Connecticut Environmental Justice Communities

Municipality	Units	MWh Produced	% of Total MWh	NOx Emitted (2019, tons)	% of Total NOx Emitted
Killingly[208]	Lake Road (3 combined cycle units)	3,409,956	20%	112	14%
Bridgeport	Bridgeport Energy (2 units); Bridgeport Harbor Station (2 units)	3,203,372	19%	239	31%
Hartford	Capitol District Energy Center, MIRA (8 jet peakers)	8,646	0%	14	1.75%
Montville	Montville Power (2 units)	11,630	0%	7	<1%
New Haven	New Haven Harbor Station (4 units)	19,691	0%	6	<1%
Waterbury	Waterbury Generation (1 unit)	11,819	0%	1	<1%[209]

In sum, Connecticut now produces more electricity than we consume in state, and we maintain thousands more MW of generation capacity than we need to serve Connecticut customers, driven by the needs of the New England region as a whole. Much of that generation capacity is fueled by natural gas and oil. These power-generating facilities generate localized financial benefits such as employment and tax revenue. Some of these facilities also benefit from tax subsidies by being exempted from the natural gas gross earnings tax.[210] They also generate localized environmental impacts, including emissions of air pollutants like NOx, SOx and fine particulate that contribute to asthma and other health impacts. Partially due to emissions from electric generators sited here to provide power to other states, Connecticut experiences some of the worst ozone pollution in the United States. Exposure to unhealthy levels of air pollution contributes to acute and chronic respiratory problems such as asthma, Chronic Obstructive Pulmonary Disease, and other lung diseases. A recent national report, Asthma Capitals 2019, ranked New Haven (#11) and Hartford (#13) among the 100 largest U.S. cities where it is most challenging to live with asthma. Connecticut's environmental permitting standards generally address these air and water impacts through unit- and technology-specific standards. As described above, however, the fact that Connecticut now hosts a disproportionate share of the region's fossil-fueled generation raises policy considerations about the cumulative air quality impacts of such facilities in the state, particularly for environmental justice and other overburdened communities.

[208] DEEP notes that Killingly was not included on the DECD list of distressed communities in 2020 and is therefore not considered an environmental justice community per CGS Sec. 22a-20a in 2020. https://portal.ct.gov/DEEP/Environmental-Justice/Environmental-Justice-Communities

[209] Section 22a-20a of the General Statutes

[210] *See* CGS Section 12-264 (exempting Lake Road Generation facility as the only facility that is as "existing combined cycle facility comprised of three gas turbines providing electric generation services, as defined in section 16-1, with a total capacity of seven hundred seventy-five megawatts"

Typically, the Connecticut Siting Council relies on the fact that a power plant has cleared the ISO-NE FCA for its "determination of need" for the new facility, a key finding to support siting a new plant. As described in Objective 2, the conflicts between the ISO-NE wholesale market design and decarbonization policies of states like Connecticut have undermined confidence that the ISO-NE's markets are efficiently and effectively determining resource needs in a manner that is aligned with the New England states' collective clean energy goals. In addition to not accounting for state policies, another concern about relying on the ISO-NE capacity market to determine need is that ISO-NE has consistently over-procured resources in the market. This is exemplified by the significant decreases in the ICR between the original auctions and the final reconfiguration auctions prior to the capacity commitment period.[211] Over the first 11 capacity commitment periods (CCPs), the ICR difference between the original auction and the final reconfiguration auction was 679 MW. The third reconfiguration auction for the twelfth CCP is expected to decline by 800 MW.[212] Though not a final reconfiguration auction, the net ICR in the second reconfiguration auction for the thirteenth CCP has declined by 985 MW.[213] Significantly overestimating ICR and procuring fossil fuel-based resources that are not needed undermines confidence in relying on the capacity market to determine need. In other instances, the ISO-NE FCA clears new gas fired power plants that have been proposed to "repower" (i.e. replace) existing coal- and oil-fired powered power plants in Connecticut. From a technical standpoint, repowering can provide incremental local environmental benefits, on a unit specific basis, by reducing NOx emissions, accompanied by regional benefits in terms of comparatively lower GHG emissions if the repowering is coupled with the retirement of the resource being repowered.

An additional concern about relying on the ISO-NE capacity market for the "determination of need" is that ISO-NE has imbedded a preference for natural gas resources over renewable resources. As discussed above in Objective 2, the capacity market design fundamentally favors generation that has low fixed costs and high fixed costs, such as natural gas resources, over generation that has high fixed costs and low variable costs, such as wind and solar.

Ultimately, the wholesale markets on which Connecticut relies need to be aligned with our State's clean energy goals, and ensure that whatever fossil-fueled power generation remains operating in Connecticut and around the region is the minimum needed to maintain reliability on our path to decarbonization. The wholesale markets also need to ensure that zero carbon resources capable of providing similar services (such as hydropower, nuclear, storage, demand response, offshore wind, and other resources) are not prevented from competing with conventional fossil resources because of antiquated market designs.

As discussed extensively in Objective 1, above, GHG emissions are global pollutants, meaning that Connecticut is affected by cumulative GHG emissions, regardless of where they occur on the planet. Because Connecticut's power needs are served by a regional electricity grid, the State has pursued its decarbonization policies on a regional basis, rather than through permitting and siting processes within the state. Energy efficiency investments in Connecticut homes and businesses, and Connecticut-funded wind farms generating power off the coast of Martha's Vineyard or in rural Vermont, are all effective at

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[211] *See* https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx
[212] *See* slide 10, https://www.iso-ne.com/static-assets/documents/2020/10/a02_pspc_2020_10_09ara_icr_values.pdf
[213] *Id.* Slide 20.

displacing fossil-fueled power generation in New England. Shutting down fossil-fueled power generation in Connecticut, however, would not (by itself) be effective in reducing GHG emissions if the ISO-NE market simply ramps up investment in fossil-fueled power plants in other states in New England to meet Connecticut's demand. This could also have the unintended consequence of prolonging the life of less efficient and higher-NOx emitting existing fossil-fueled plants in Connecticut, such as those in Table 4.2, above—a serious environmental justice concern.

As Connecticut works to achieve its decarbonization goals, it is worth evaluating measures from the standpoint of their ability to contribute to fossil fuel generation retirements, both in the state and around the region. Pathways pursued to meet the state's decarbonization goals must consider the impact that chosen pathways will have on fossil fuel retirements. As noted in Objective 1, different scenarios for meeting a 100% zero carbon target for Connecticut have varying impacts in terms of the amount of fossil fuel retirements that occur across the region. Resource procurements should be carefully planned to maximize fossil fuel retirements while maintaining reliability, to ensure that both GHG emission and local air quality benefits are maximized.

The State of Massachusetts has established an in-state cap on GHG emissions that applies only to generation located in that state. An evaluation of the application of a similar policy in Connecticut yields some insights for policy measures that could help to ensure that large-scale fossil generation in the state (new and existing) continues to be incented to lower emissions in a manner that—in certain circumstances—does not increase rates for Connecticut electric customers, and fairly and equitably compensates ratepayers and local communities for the burdens of hosting a disproportionate share of the region's generation.

As noted above, starting around 2010, Connecticut shifted from being a net importer of electricity to a net exporter of electricity, which has been an increasing trend. In 2010, Connecticut exported about 200,000 MWh of electricity, while in 2018, Connecticut exported approximately 8.5 million MWh of electricity. Since the 2010 timeframe, approximately 3,000 MW of new natural gas plants have been, or are expected to be, constructed in Connecticut. Only about 1,200 MW of new natural gas generation has been constructed in the rest of New England.

A fee assessed on large fossil-fueled electricity generators located in Connecticut, based on the tons/MWh of carbon emissions generated, and incremental to each plant's requirement to purchase greenhouse gas emission allowances to comply with the Regional Greenhouse Gas Initiative (RGGI) would reduce plant run times in the state. Fossil fuel powered plants located in Connecticut that are 25 MW or bigger and do not receive a set-aside pursuant to 22a-174-31(f)(4)(B) or 22a-174-31(f)(4)(F) would pay the tax on each ton of carbon dioxide emitted, and the revenues would be remitted to the State. These Connecticut plants would presumably incorporate the cost of the tax into their energy price—i.e. the price they bid into the ISO-NE wholesale energy market—causing them to run less frequently (and generate fewer overall emissions of GHGs, NOx and other air pollutants) relative to other fossil-fueled power plants in the region that are not subject to the tax.

Wholesale energy prices would be expected to increase accordingly, and this would impact Connecticut ratepayers in two ways. First, the increase in wholesale prices would be expected to increase the cost of electricity embedded in consumers' generation rates; at the same time, it would *reduce* the cost of power purchase agreements (PPAs) and contracts for differences that are recovered through consumers' distribution rates as the energy revenues generated would be higher than expected in the original contracts. Therefore, an important consideration for designing such a tax would be to impose the tax at a level that would lower emissions and provide net neutral revenues for Connecticut ratepayers, by ensuring that the revenue from the tax and the savings on the cost of PPAs would flow back to electric ratepayers and exceed the increased wholesale electricity costs. Such a scenario would thus provide a measure of compensation to Connecticut residents for hosting such a large share of regionally used fossil-fueled generating plants.

A range of carbon prices was modeled to evaluate the applicability of a Massachusetts-style in-state carbon price in Connecticut. The results of this modeling (included in Appendix A7) indicate that a carbon tax of $6.03/short ton (nominal) would result in $23.30 million in tax revenue in the modeled year 2025, and $9.50 million in additional revenue from existing contracts, which would more than offset the increase in wholesale energy prices associated with the tax if all of the tax revenue were credited back to Connecticut ratepayers. At the $6.03 price, CO_2 emissions would decline by 31 percent within Connecticut as in-state facilities run less frequently. But overall CO_2 emissions would remain relatively the same region-wide (decreasing by about 1 percent), as fossil fueled power plants in other states would increase their run times to make up for the decrease in generation from Connecticut plants. In-state emissions of other air pollutants would also remain relatively the same.

Any higher carbon price would not result in a net neutral or positive price impact for Connecticut ratepayers because wholesale energy prices would increase beyond the value of the tax revenue and revenue from existing contracts. Under the highest carbon tax of $104.54/short ton, wholesale energy prices increase by about $5.00/MWh. A modest Connecticut-only carbon fee would generate sufficient revenue to make the tax a net benefit for Connecticut ratepayers, but it will also increase reliance on less efficient out-of-state generation that will not be subject to the tax. In addition, the increased energy market revenues of $5.00/MWh are likely insufficient additional revenue to incentivize zero carbon resources to build based on energy revenue alone. Finally, under the consumption-based accounting method in this IRP, this tax would not help Connecticut meet its zero carbon goals because regional emissions would remain effectively unchanged.

Siting of Zero Carbon Power Generation in Connecticut

As the State continues to deploy zero carbon resources to achieve its climate goals, it is important to ensure that renewable and other resources needed for decarbonization can be developed and constructed in a manner that carefully balances all of our environmental goals. Zero carbon energy deployment must align with land use, natural resource, and environmental quality policies and standards. Proper planning and siting will minimize uncertainties and conflicts during siting and permitting processes. The more efficient these practices are, the faster the deployment of these renewable resources. The Department is uniquely suited to integrate these efforts as the agency responsible for energy planning, environmental protection and natural resource conservation.

Solar Siting

The opportunities for siting solar in Connecticut are expansive, but the potential environmental impacts of solar vary greatly based on where the panels are placed. For example, rooftop facilities provide for minimal impacts by utilizing existing buildings, preserving greenfields, and not increasing stormwater runoff. The environmental impact of ground-mounted projects varies greatly, depending on the existing use and physiographic attributes of the site. Ground mounted projects can have impacts on water and land and natural resources including stormwater and wetlands, endangered and threatened species, core forests and prime farmlands.

Sequencing of steps in the siting and development of solar facilities is complicated and many processes are intertwined. An early and thorough assessment of the challenges associated with developing a site is fundamental to smoothly navigating the regulatory process. For example, performing hydrological evaluations, biological inventories and detailed wetlands mapping early in design will facilitate minimizing environmental impacts and keeping redesign to a minimum.

The Department has been actively investing in more innovative approaches to its internal processes associated with solar siting. For example, the Natural Diversity Data Base (NDDB) process is being moved to an online platform, which will facilitate quick responses on a majority of inquiries. This will also facilitate earlier submission of a permit application or general permit registration for construction storm water activities. The Department is also currently revising its Construction Stormwater General Permit and anticipates issuing a new general permit in the very near future. Incorporated into the permit are updated requirements which will inform solar siting and storm water control design both during and post-construction. Enhancements in the revised general permit will formally establish financial assurance mechanisms and more clearly define the roles, engagement and accountability of permittees and their design qualified professionals, contractors and subcontractors, qualified inspectors, and DEEP's Soil and Water Conservation District representatives, to assure storm water controls are properly implemented and maintained in accordance with the Stormwater General Permit throughout the duration of the project.

Providing clarity, predictability, and upfront assistance to developers to ensure projects can be built quickly and with minimal siting and permitting conflicts is critical to achieving DEEP's environmental missions while supporting the State's zero carbon energy goals. The Department has undertaken a number of steps in this regard. For example, over time DEEP has adapted more eligibility requirements into DEEP-run grid scale RFPs to incorporate siting practices up front; similar requirements should also be incorporated into tariff-based procurements for ground-mounted projects as well. To help developers navigate the permitting process for solar arrays, DEEP recently published a Fact Sheet that provides information on the types of permits that may be required and the timing and sequencing of those permits.[214] The Department also encourages applicants to request a pre-application permitting meeting with DEEP staff early in the planning of a solar development project, prior to or coincident with submission to the Connecticut Siting Council, to understand the regulatory and NDDB requirements and estimated timelines associated with the project.[215]

The Department will conduct a stakeholder process to explore best practices and innovative approaches to better coordinate the solar siting process as further set forth in Strategy 10.

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[214] Information for Solar Developers: An Environmental Permitting Fact Sheet, https://portal.ct.gov/-/media/DEEP/Permits_and_Licenses/Factsheets_General/Siting-Solar-Fact-Sheet.pdf

[215] To request a pre-application meeting, developers can complete the Pre-Application Questionnaire (link) and submit it to https://portal.ct.gov/-/media/DEEP/Permits_and_Licenses/Factsheets_General/preappquestionnairedoc.doc

Offshore Wind Siting

Offshore wind developments and peripheral structures (e.g., transmission lines) may occur on either federal submerged lands (e.g., the Outer Continental Shelf) or state submerged lands. Those on Federal lands may only be sited in lease areas designated by the Bureau of Ocean Energy Management (BOEM)[216] following review and consultation pursuant to the National Environmental Policy Act (NEPA). Despite NEPA review and consultation, project siting will limit but not avoid all impacts to the environment and industries, such as commercial fishing. Potential environmental impacts include disturbing protected species such as the North Atlantic right whale and disturbing benthic habitat; industry impacts include blocking transit lanes and disruption to commercial fishing areas.

The State of Connecticut's jurisdiction relative to projects and project elements sited on federal lands is limited. Those limitations include engagement in the NEPA review and consultation procedures, Coastal Zone Management Act consistency in some cases, and the State's Requests for Proposals (RFP) for offshore wind projects. Connecticut's engagement in the NEPA procedures may be through direct petition and/or through membership in the Atlantic States Marine Fisheries Commission and the New England Fishery Management Council, and the advisory roles those entities have with the National Marine Fisheries Service within the US Department of Commerce. Conversely, one of the direct opportunities the State has to influence the environmental and economic impacts of offshore wind development is through its procurement activity—i.e., by including terms and conditions in Requests for Proposals and model power purchase agreements for offshore wind projects financed by Connecticut ratepayers.

The Department's RFPs commonly include threshold requirements for siting and planning for environmental impacts, which DEEP can review and evaluate as part of the proposal packages from developers. This was born out in DEEP's most recent offshore wind solicitation in 2019. In addition to giving DEEP authority to procure up to 2,000 MW of offshore wind power, Public Act 19-71 required that the DEEP Commissioner establish a Commission on Environmental Standards.[217] The Commission on Environmental Standards met during the summer of 2019 to develop a report on best practices that DEEP should employ when crafting the first RFP under Public Act 19-71.218

Based in large part on the Commission on Environmental Standards' report, DEEP required the submission of an Environmental and Fisheries Mitigation Plan (EFMP) intended to improve environmental outcomes at a chosen site. Three threshold requirements of the EFMP obliged bidders to:

1) include an adaptive plan with clearly identified stakeholders, a stakeholder engagement process, a plan for pre-construction and risk assessment, a process to avoid, minimize, and mitigate risks to stakeholders throughout the project phases, and a reporting schedule on that plan;

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[216] U.S. Bureau of Ocean Energy Management. Lease and Grant Information. *Available at:* https://www.boem.gov/renewable-energy/lease-and-grant-information

[217] Public Act 19-71. An Act Concerning the Procurement of Energy Derived from Offshore Wind. *Available at:* https://www.cga.ct.gov/2019/act/pa/pdf/2019PA-00071-R00HB-07156-PA.pdf

[218] State of Connecticut. Report and Recommendations of the Commission on Environmental Standards for Minimizing and Mitigating Environmental and Commercial Impacts of the Construction and Operation of Offshore Wind Facilities. August 7, 2019.

2) address how they will inventory, avoid, minimize, and mitigate the following specific hazards: risk to commercial fisheries, risk to marine mammals and sea turtles with specific reference of underwater sound and collision, risk to birds and bats, and risk to other species; and

3) include a data reference and sharing plan that addresses coordination with relevant regional working groups and a plan to store and share inventory and monitoring data.[219]

It is very unlikely that Connecticut will see a proposal to build offshore wind turbines in Long Island Sound ("the Sound"), which has relatively low wind potential compared to federal lease locations. It is more feasible that offshore wind projects sited on federal submerged lands will need to be interconnected via transmission lines that transverse state submerged lands, such as Long Island Sound. Should that occur, Connecticut would have another planning tool at its disposal. The Long Island Sound Blue Plan ("The Blue Plan"), developed by a multi-stakeholder Blue Plan Advisory Committee and awaiting approval by the state legislature,[220] is an inventory of the natural resources and human uses in the Connecticut waters of Long Island Sound and a spatial plan to guide future use of the Sound's waters and submerged lands.[221] The Blue Plan can act as a guide for developers siting transmission lines in Long Island Sound to ensure that environmentally sensitive areas and high human use areas are taken into consideration on the front end of siting and planning. The Blue Plan policies will also guide existing state permit processes that apply to transmission lines through the Sound, particularly DEEP coastal permits and Siting Council authorization.

The Department recognizes that states across the region are procuring offshore wind in the same or adjacent federal lease areas and thus are grappling with the same challenges with regard to siting and environmental and fisheries mitigation. Coordination with regional entities that are investigating these issues, such as the Northeast Regional Ocean Council, the Responsible Offshore Development Alliance/Responsible Offshore Science Alliance, and current efforts to establish a Regional Wildlife Science Entity for Offshore Wind, can improve our understanding of the best available science, tools, and practices for environmental and commercial fisheries mitigation and allow us to continually improve our solicitations as they pertain to planning and siting. The Department will leverage these regional approaches to developing best practices in offshore wind siting. As required by Public Act 19-71, DEEP will also utilize input from the Commission on Environmental Standards for each future solicitation pursuant to that Public Act.

[219] CT DEEP. Notice of Request for Proposals for Offshore Wind. August 16.2019. Facilitieshttp://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/ccf12ec6cdf19ca7852584580072434d/$FILE/2019.08.16_Final.OSW.RFP.pdf

[220] The Final Draft of the Blue Plan was submitted to the Connecticut General Assembly's Environment Committee, per statutory requirement, prior to the start of the legislative session that began on February 5, 2020. That legislative session was cut short before action was taken on the Blue Plan due to the COVID-19 pandemic. It is expected that the Final Draft of the Blue Plan will go before the legislature again during the 2021 legislative session, where favorable votes by the Environment Committee, the State House, and the State Senate would constitute final approval of the Blue Plan.

[221] https://portal.ct.gov/DEEP/Coastal-Resources/LIS-Blue-Plan/Long-Island-Sound-Blue-Plan-Home

Strategies to Achieve Objective 4

The Department recommends pursuing the following strategies in furtherance of Objective 4, Optimal Siting of Generation Resources.

- Adoption of the 100% Zero Carbon Target for the state's electricity supply (Strategy 1) will ensure that the state can clearly plan for and achieve a decarbonization goal that will, in concert with similarly robust targets being adopted by other states in the New England region, minimize operation of fossil fuel generation in the region. As noted in Objective 1, different pathways to achieve that 100% Zero Carbon Target will result in greater or lesser retirements of fossil fuel resources, depending on the level of ambition of other states' targets, and maximizing fossil fuel retirements—including not only baseload gas units that emit large quantities of GHGs but also older peaking units that contribute the greatest amount of NOx emissions and air quality impacts in environmental justice communities—will require a policy and procurement focus on ensuring that reliability needs are met with zero-carbon resources, whether that is transmission, energy conservation, demand response, storage, hydropower, or continued operation of nuclear (Strategies 4, 5, 12, and 13).
- Pursuing reforms of the wholesale electricity markets (Strategy 2) is equally critical. These reforms are needed, at a minimum, to put an end to ISO-NE market rules that over-procure capacity, prevent state clean energy investments from clearing in the capacity market, and imbed preferences for natural gas and other fossil resources in the capacity market, such as providing for a full capacity rating for generating facilities reliant on pipeline natural gas that are not able to run reliably during winter cold snaps. Fully reforming the market will ensure that zero carbon resources are selected to meet public policy and reliability needs.

These and other strategies are needed to ensure continued, comprehensive progress in reducing emissions not only from new natural gas facilities, but also from the oldest fossil fuel power plants that are the largest emitters of harmful air pollution in environmental justice communities.

In addition, Connecticut must fully merge its environmental and energy policies by incorporating eligibility criteria in renewable energy procurements that reflect a consistent and appropriate balance of price and environmental quality and natural resource values, and providing transparent, predictable and efficient permitting and siting processes for renewable energy resources. The Department will convene a stakeholder process to examine best practices in solar siting and provide transparency and predictability to developers (Strategy 10). As noted in Objective 2, the Department also recommends that PURA structure the successor tariff programs to incorporate eligibility requirements that minimize land use and environmental quality conflicts, and incentivize the use of previously disturbed sites for solar facilities.

Objective 5: Transmission Upgrades & Integration of Variable and Distributed Energy Resources

As noted in Objective 1, the transmission system's ability to deliver increasing amounts of variable clean energy resources is vital to cost-effective and reliable decarbonization in the coming decades. Similarly, as behind-the-meter resources become an increasingly substantial portion of Connecticut's energy supply, investments in a "modern" grid—capable of monitoring, dispatching, and/or controlling distributed solar, storage, and other resources—is also critical. Increasing quantities of zero carbon reserves—such as storage and demand response--will be needed to balance variable renewable resources to achieve a reliable, low-emission electric system. Careful planning and improvement of both transmission and distribution systems will become even more essential as electrification of thermal and transportation sectors accelerates.

This section discusses complementary efforts needed to reliably and efficiently integrate clean energy resources, including: (1) planning and procurement of transmission, and (2) the advancement of energy efficiency, demand response, and storage to reduce load and balance intermittent resources. It should also be noted that PURA has underway a comprehensive effort to modernize the EDCs' distribution grid, pursuant to Docket Number 17-12-03.

The New England Regional Transmission Grid

Today's wholesale electric power system, and the electric markets it supports, depends on an increasingly integrated network of high-voltage power lines, substations, and control facilities that provides numerous economic, security, environmental, public policy and reliability benefits to ratepayers. The ISO-New England is responsible for planning, developing, and operating the grid but the power lines, transformers, and substations are owned by the independent, regional transmission operators (RTOs or TOs). Under the Transmission Operators Agreement, the RTOs are obligated to maintain their transmission assets consistent with applicable safety and reliability standards under the oversight of ISO-NE. Their operations and maintenance cost and the costs of approved new projects and upgrades are then regionalized through regional network service (RNS) rates by load share. Transmission rates are subject to FERC approval, and are directly passed through to Connecticut electric ratepayers' bills.

There is no routine proactive planning cycle in ISO-NE to facilitate the interconnection of generation resources. While the ISO-NE reliability planning process does plan ten years into the future, it does not consider public policy, and therefore does not align with State clean energy goals. For generator interconnections. The ISO-NE conducts essentially a reactive planning process analyzing reliability and congestion issues and, of course, maintains the Interconnection Queue ("the Queue") of transmission upgrade and service requests. Developers must submit planned projects into the Queue and projects are studied by ISO-NE in the order submitted.

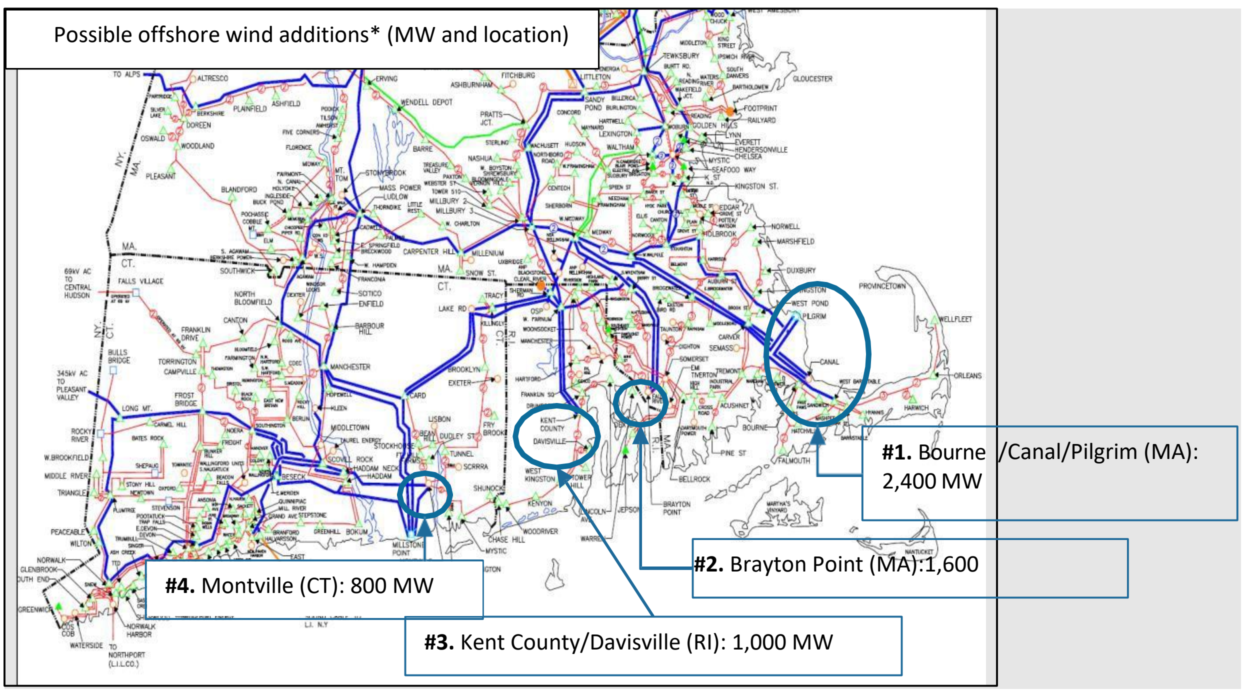
To reach State decarbonization goals it will be necessary to unlock the full potential of the clean energy resources being deployed. To do this, it will be necessary to address four issues. The first is how to both make the best use of the existing transmission assets while making the needed new transmission upgrades affordably and equitably. The second is how to fully integrate resources like offshore and land-based wind that are located far from load centers The third is how to reconfigure the topology of the grid to achieve full integration of distributed and BTM resources while adapting gird operations effectively to accommodate new clean generation resources. Finally, it will be necessary to accomplish the above listed goals through a scenario-based proactive planning process that cooperatively involves ISO-NE transmission planners with State personnel at all relevant stages of planning and development and effectively encourages competition.

Unlocking Clean Energy Resources

State decarbonization policies are changing the grid. Wind power comprises more than two-thirds of new resources in the interconnection queue and solar and battery resources make up another quarter.222 Beyond this, there are hundreds of thousands of BTM solar installations currently in operation in the region and it is vital to plan for the changes in demand these resources create.223

Some of these resources, like large-scale hydropower, land-based and offshore wind, provide very high capacity values but are located far from load centers and need new transmission. Offshore wind, for example, located off the coast of Massachusetts and Rhode Island, can initially interconnect at only a finite number of PTFs) along the coast and many of these are already approaching the limit of their capacity with just the 3142 MW of offshore wind that Connecticut, Massachusetts and Rhode Island have already contracted. See Figure 5.1.

Figure 5.1: Coastal Transmission Interconnection Points Available for Offshore Wind Resources[224]



[222] Id., p. 13
[223] Id., p. 18.
[224] ISO-NE 2019 Economic Study Offshore Wind Transmission Interconnection Analysis, May 20, 2020. https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf

Offshore wind is a central element of Connecticut's pathway to achieve a reliable and equitable zero carbon electric supply. Presently, Connecticut has contracted for just over 1100 MW of offshore wind, while Massachusetts has procured about 1600 MW with another 1600 MW more in the near future. Rhode Island has 400 MW under contract and will soon issue an RFP for 600 MW.[225] Therefore, the three New England states have a total of 3,142 MW already under contract and up to 5,342 with the new Massachusetts and Rhode Island procurements. Objective 1 concludes that Connecticut would eventually need an additional 3,745 MW under the Base Load Balanced Blend scenario or 5,710 MW under the Electrification Load Balanced Blend scenario, to meet the 100% Zero Carbon Target in 2040. If combined with the amount already contracted or out for RFP, OSW capacity would thus total 9,087 or 11,052 MW, under the Base Load Balanced Blend scenario or the Electrification Load Balanced Blend scenario, respectively. This amount of OSW is within the expected total capacity of the BOEM leaseholds located off southern New England, which is currently estimated at between 11 to 14 GW.

This quantity of offshore wind will not be able to interconnect into the regional grid without transmission upgrades. ISO-New England planners have stated that "[b]ased on the currently expected transmission for 2030, ISO-NE anticipates that [5,800 MW] of offshore wind additions have the potential to be accomplished without major additional 345 kV reinforcements."[226] However, there are two important caveats. The first is that these studies assume interconnection only; not full integration of the capacity of the wind farms, and not at full nameplate capacity. That means the offshore wind projects may be able to reliability interconnect to the grid, but a significant amount of the energy from those generators will not be deliverable to consumers. The second is that the ISO's 5800 MW estimate assumes that offshore wind generators will be distributed across the interconnection points shown in Figure 5.1. If instead, offshore wind generator interconnections are clustered on Cape Cod, there may be a need for additional transmission infrastructure to reliably export power out of Cape Cod and the SEMA/RI zone into the full New England grid. ISO-New England has indicated that there may be a "hard ceiling" at some or all of the PTF points that would prevent interconnection of more than approximately 7,000 MW without extensive new transmission development on new rights-of-way. The studies to evaluate that are just beginning and will take time to complete. The clear takeaway is that potential transmission constraints need to be fully evaluated before Connecticut and other states conduct procurements for wind resources beyond those already contracted or authorized under existing statutes. Therefore, meeting the long-term goals of this IRP will require proactive planning for transmission to ensure that incremental wind turbines can be interconnected, and operate without curtailment.

In addition to unlocking offshore wind and other new grid scale resources, transmission upgrades will be also needed to address changes caused behind-the-meter and other resources. States have invested significantly in BTM solar in the past two decades, resulting more than 3,400 MW of BTM solar PV nameplate capacity in the region.[227] Today, BTM solar PV resources reduce the region's gross load by approximately three percent, and have changed the nature and shape of the demand curve, particularly

[225] Press Release. Raimondo calls for up to 600 MW of new offshore wind energy for Rhode Island. October 27, 2020. https://www.ri.gov/press/view/39674
[226] 2019 Economic Study Offshore Wind Interconnection Analysis, May 20, 2020, p. 5.
[227] 2020 Regional Electricity Outlook, p. 13

during the summer months.[228, 229] The deployment of significant energy efficiency and behind-the-meter solar has already enabled a sharp drop in demand at certain times resulting very light load conditions which then abruptly reverse as daylight hours come to an end, and demand rises.[230] Light load conditions can present high-voltage and other issues which can be challenging for the grid operator to manage.[231] This, in turn, can result in the need for new voltage control systems and operating measures. Thus, even with the substantial investment in the transmission system in recent years, ISO-NE notes that it will be necessary to upgrade the system to affordably integrate VERs that affect supply, and resources that affect demand.[232]

In short, the transmission system for a traditional fossil-fuel system with dispatchable generation (*i.e.*, fossil fuel-based power plants in or near urban areas) is very different from a transmission system based on inverter technologies with generation that is variable and is often located at a distance from load (*i.e.,* windfarms or other resources located far from city centers). In fact, most of the zero carbon resources needed to meet Connecticut's policies are "inverter-based" resources, which present unique needs for transmission planning. ISO-New England recognized this and stated in its Regional Systems Plan 2019:

> The widespread addition of inverter-based technologies (which use power electronics to convert between alternating current [AC] frequencies or between AC and direct current [DC] frequencies) and distributed energy resources (most which the ISO cannot observe or control like traditional resources) would require transmission upgrades and control system improvements for reliably interconnecting these resources to the grid. Structural changes to the transmission and distribution systems are being analyzed and implemented, and new procedures put in place, to help transform the grid and improve the reliable, economical, and environmental performance of the system overall.[233, 234]

Considering the amount of inverter-based or variable energy resources that could be developed over the IRP forecast period, it will be necessary to upgrade the region's transmission grid. Interregional transmission planning is vital to ensure the most efficient development of OSW and other zero carbon resources.

As of September 2020, ISO-NE has begun a process of identifying and testing changes to transmission planning assumptions to address some of the technical issues presented by clean energy resources in

[228] *Id.*
[229] 2019 Regional System Plan, pp. 155-159.
[230] Id. p. 159, fn 324.
[231] Id. p. 156.
[232] Id. Pg 157
[233] ISO-NE Regional System Plan 2019, p. 1.
[234] Inverter-based technologies include wind, photovoltaics resources, high-voltage direct-current (HVDC) facilities, battery energy-storage systems, and flexible alternating current transmission system (FACTS) devices, which can help regulate voltages and improve the stability performance of the system. Distributed energy resources (DERs) are sources and aggregated sources of electric power not directly connected to a bulk power system. DERs include generators (i.e., distributed generators) and energy-storage technologies capable of exporting active power to an electric power system.

the reliability planning process.[235] This effort aims to address issues such as decreased daytime load due to BTM solar, stability issues presented by inverter-based generations, and substantial increases in offshore wind generation. However, these changes are not coordinated with State clean energy goals, and do not consider public policy as a factor in determining planning assumptions. Instead, these changes to the reliability planning process are reacting to changing system conditions, and do not address the resource additions projected the modeling Objective 1.

Reducing Curtailment through Transmission Upgrades

Not only can transmission upgrades increase the amount of available zero carbon resources (i.e. unlocking land-based wind in Northern New England), but they can also increase the amount of energy available from zero carbon resources that are expected to come online. The issue of curtailment, as discussed in Objective 1, arises when the amount of energy being supplied to the grid exceeds what the grid can actually support, thus causing the excess to be "spilled" or curtailed. The modeling results indicate that zero carbon energy is curtailed across the region, particularly in the later modeled years as an increasing amount of variable energy is brought online to meet the Regional Emissions Target. Alleviating transmission constraints can reduce, though not entirely eliminate, these curtailments. Figures 5.2 and 5.3 show the amount of VERs curtailed regionally over the years, expressed in terms of percentage of resource capacity, in both the Base Load Balanced Blend and Electrification Load Balanced Blend scenarios. Figures 5.4 and 5.5 show that same information under the scenarios that eliminate transmission constraints (i.e. upgrades are implemented), showing a significant decline in curtailments and highlighting the potential value of relieving these constraints in unlocking zero carbon energy potential. This effect is further pronounced under the Electrification Load, which requires even more VER capacity to achieve the Regional Emissions Targets.

[235] Transmission Planning for the Future Grid https://eversourceenergy.sharepoint.com/teams/GRPISOPolicy/Shared%20Documents/General/Maps/ISO%20Queue%20Maps/Storage_queue_map_details_nolayers.pdf?CT=1607535161363&OR=ItemsView

Figure 5.2: VER Regional Curtailments, Base Load Balanced Blend Scenario

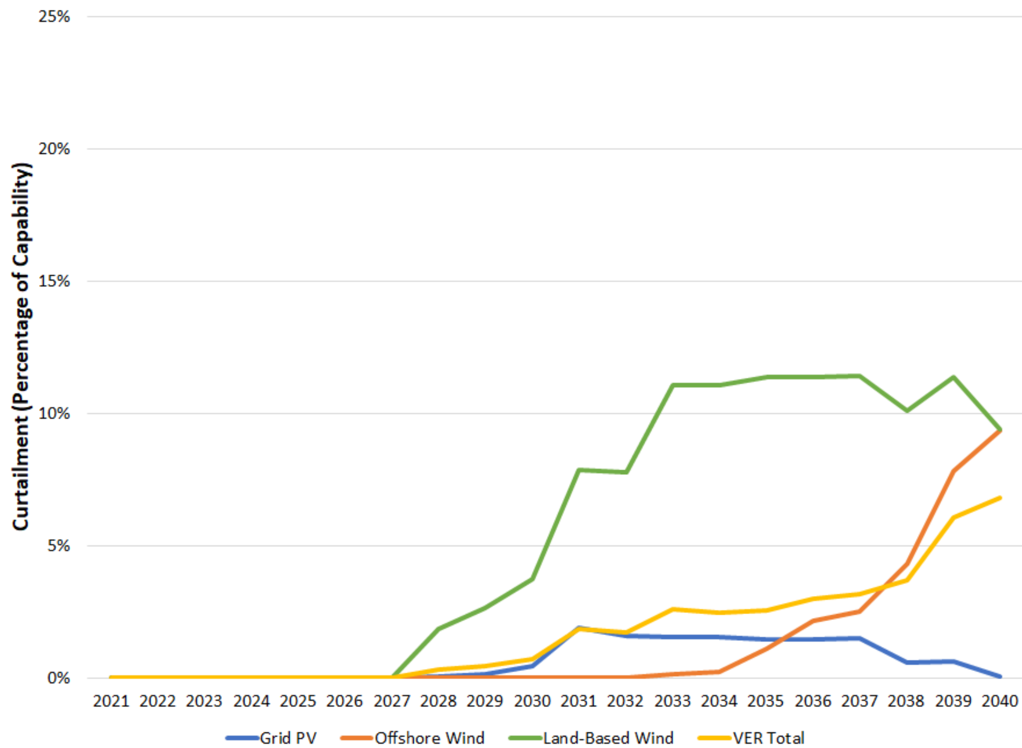


Figure 5.3: VER Regional Curtailments, Electrification Load Balanced Blend Scenario

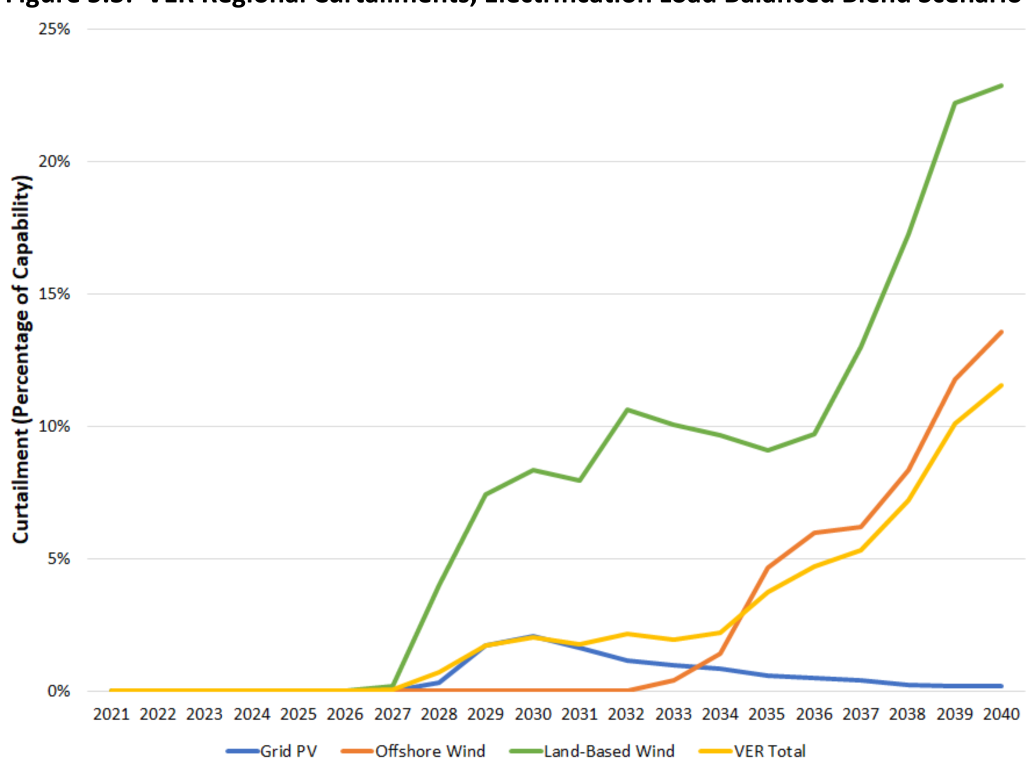


Figure 5.4: VER Regional Curtailments, Base Load Transmission Scenario

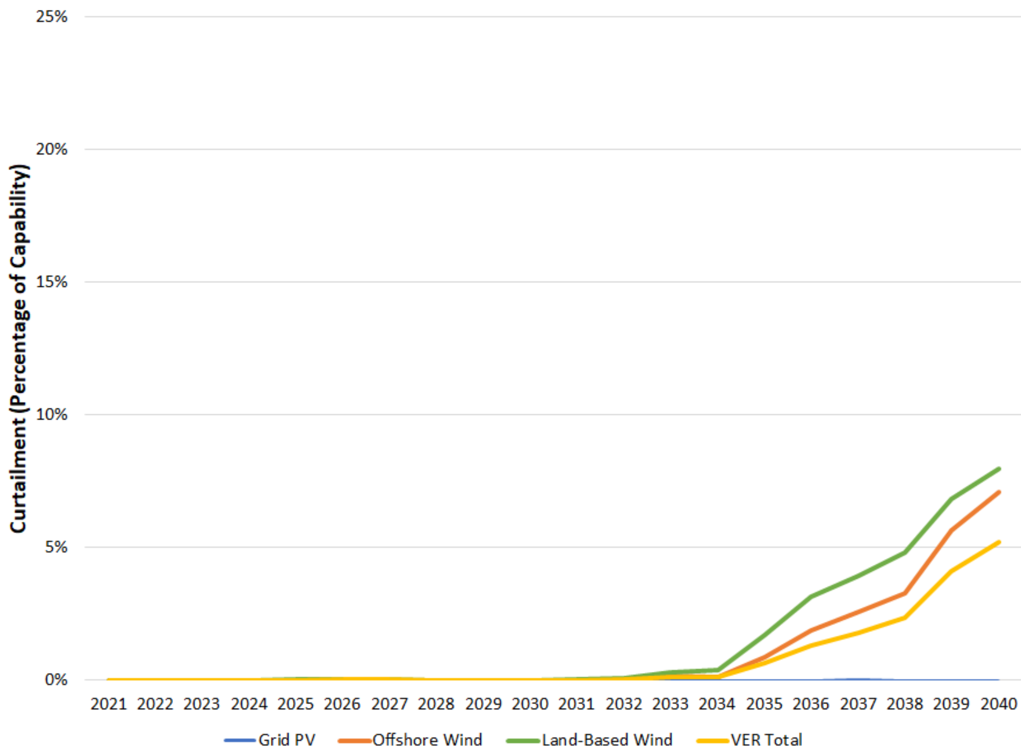
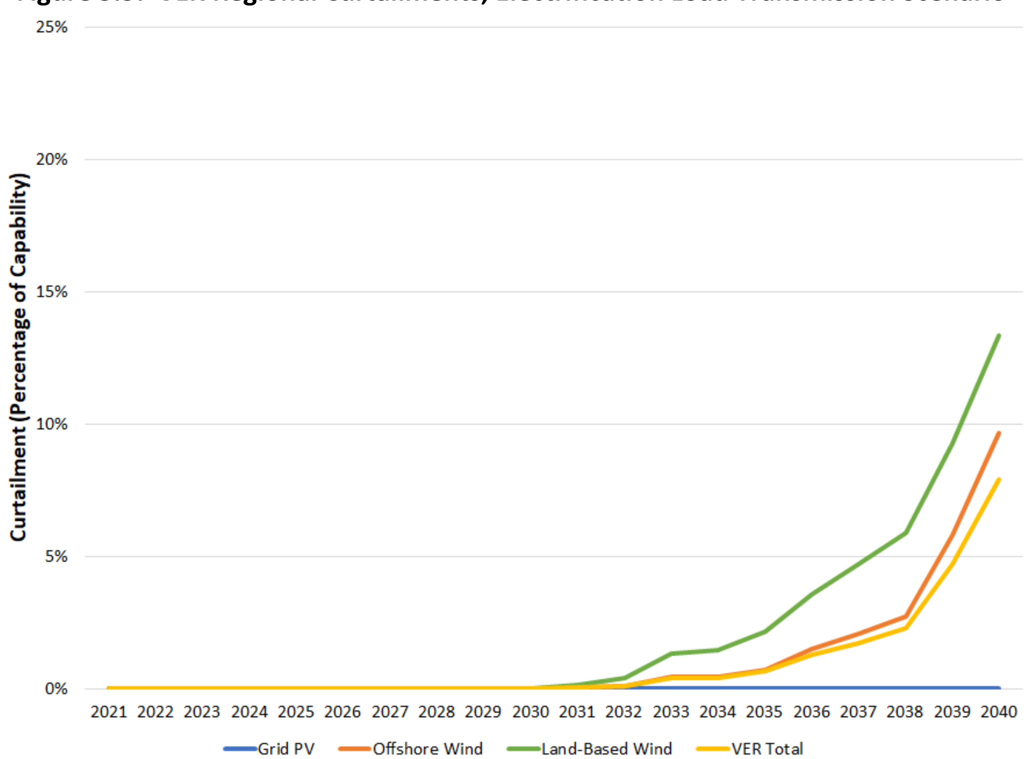


Figure 5.5: VER Regional Curtailments, Electrification Load Transmission Scenario



Transmission Upgrade Planning Needs to Begin Now

Major transmission projects in ISO-NE in recent years have faced significant delays or have simply failed.[236] An analysis performed by the Brattle Group notes that "[t]ransmission projects require at least 5-10 years to plan, develop, and construct; as a result, planning would have to start now to more cost-effectively meet the challenges of changing market fundamentals. . . ."[237] Comparatively, DEEP has successfully completed procurements for grid-scale solar with in-service dates 2-5 years later, some expected and others achieved. For DEEP OSW procurements, there is an expected in-service date five years later. The State is able to procure resources faster than the transmission grid can adapt; thus, it is critical to ensure the transmission system is capable of delivering the significant quantities of zero carbon resources identified in this IRP.

As noted above, considering the amount of inverter or VER resources planned in this IRP over the forecast period, it will be necessary to comprehensively upgrade the region's transmission grid. Interregional transmission planning is vital to ensure the most efficient development of OSW and other zero carbon resources. ISO-NE recognizes this in its 2020 Regional Electricity Outlook: "To achieve decarbonization goals, the region must be proactive in developing infrastructure that aligns with supply growth and is available when needed."[238]

Under the current ISO-NE tariff, proactive planning for clean energy integration is a challenge. To date, the basic approach to generator interconnections has been primarily reactive in that developers take a queue position on a first-come-first-served and are studied in order by ISO-NE planners. The current process is misaligned with state efforts to transition to clean energy. The region's shift toward more offshore and onshore wind, hydroelectric resources, solar PV, and battery storage continues. Yet, the FERC Order No. 1000 planning process for public policy transmission projects is not functioning as intended; in fact, in the years since Order 1000 was issued, no public policy transmission projects have been built in ISO-NE, largely due to concerns with cost allocation and a lack of transparency to and control by the states. We need an alternative to this approach, and State officials are convinced that a forward-looking, scenario-based proactive planning process is needed. Absent such a proactive transmission planning process, the region will be unable to effectively plan for the widespread integration of these clean energy resources and DERs. For example, the bulk transmission grid is required to serve less demand as a result of the ever-growing adoption of small scale distributed generation like rooftop solar PV, but must also reliably support rapid changes in demand as the sun goes down. These issues will only intensify as the state sees growth in electrical demand due to the electrification of the transportation and heating sectors. A proactive transmission planning process will better integrate transmission planning with state DER policies and help to anticipate the amount and type of transmission infrastructure needed; we know this clean energy transition is occurring and a planning process that acknowledges and accounts for this fact rather than relying on a reaction-based planning model or an ineffective FERC Order No. 1000 framework is essential for a successful and cost-effective transition.

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[236] For example, the Northern Pass project, a 192-mile long 1200 MW transmission line, was abandoned after eight years of effort in the face of significant opposition. The company took a write-down of $240 million. http://indepthnh.org/2019/07/25/eversource-gives-up-northern-pass/

[237] Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future, Chang, Judy and Pfeifenberger, Johannes, June 2016, The Brattle Group, pp. Iii, 4. See also Transmission Incentives NOPR, Docket No, RM20-10, WIRES brief, p. 7, " time is of the essence, as state-mandated renewables goals with targets as early as 2030 are fast-approaching, while transmission projects in this country can face a timeline for development of roughly ten years or more."

[238] 2020 Regional Electricity Outlook, p. 15

Load Reduction and Balancing through Energy Efficiency, Demand Response, and Storage

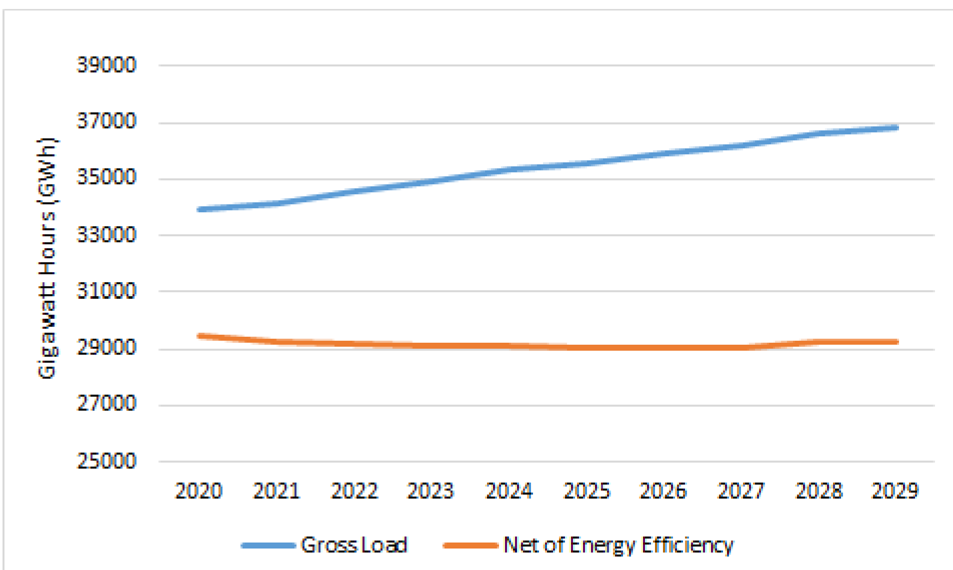
As made clear by this Objective, integrating the amount of variable energy resources, both grid-scale and behind the meter, necessary to meet the targets outlined in Objective 1 will require upgrading the existing New England transmission system to mitigate curtailments and reduce congestion. However, there also exist non-wires alternatives (i.e. measures or technologies that do not involve upgrades to the transmission system) that can help achieve these same outcomes. Non-wires alternatives typically include energy efficiency, demand response, and storage measures.

Energy Efficiency

Energy efficiency is a critical resource in Connecticut's energy mix. Not only does it help to reduce overall and peak loads, but it is also an option ratepayers can pursue to manage their energy costs by reducing their consumption. In 2019 alone, the State's C&LM programs, implemented under DEEP's authority pursuant to Connecticut General Statute Section 16-245m, reduced demand by an amount equivalent to a 149 MW power plant, saving ratepayers an estimated $67.5 million in energy costs and avoiding 228,142 tons of CO_2 emissions.[239]

Figure 5.6 demonstrates the demand reduction projected to occur through the implementation of Connecticut's energy efficiency investments at current levels over the next decade. Absent Connecticut's investments in efficiency, our energy consumption would be 14 percent higher on average each year.

Figure 5.6: Projected CT Load Net of Energy Efficiency Savings[240]



[239] *See* Connecticut Energy Efficiency Board, 2019 Programs and Operations Report, March 1, 2020, *available at* https://www.energizect.com/sites/default/files/Final-2019-Annual-Legislative-Report-WEB02262020_2.pdf.

[240] *See* ISO-NE, 2020 CELT Forecast Detail, *available at* https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

The significance of these energy savings has long been recognized by the State and by Governor Lamont, who protected the C&LM Plan budget from being diverted to the general fund in 2019 as it had been in 2017.[241] Section 16a-3a(c) of the Connecticut General Statutes requires energy efficiency and demand-reduction strategies to be prioritized as the first resource to meet the state's energy needs, before new generation resources are procured. In addition, Connecticut must meet its statutory target for energy demand reduction of 1.6 million MMBTU per year beginning in 2020 through 2025, reinforcing the importance of the C&LM programs.

Consistent with these policies, DEEP incorporated the above projections of energy efficiency into the expected annual load through the modeling horizon of this IRP (see Objective 1 and Appendix A1). These energy savings—estimated annually by ISO-NE—are based on historical trends in Connecticut's investment in energy efficiency and resulting energy savings. In the Electrification Load scenarios, DEEP assumed increased energy efficiency would be achieved through measures corresponding to conversions to electric heat pumps, helping to mitigate the increased load necessary to meet Connecticut's climate goals. For further details on the energy efficiency projections and assumptions used in this IRP, see Appendix A1.

Energy efficiency measures are essential in all scenarios, because they help to both drive down energy consumption and GHG emissions and minimize costs by avoiding the need for additional procurements. The impact of energy savings on GHG emissions is greatest in the earlier years of the forecast while the energy market is still transitioning to zero carbon, though by 2040 the region is anticipated to achieve over 46,000 GWh of energy savings under the Base Load scenarios, and over 54,000 GWh under the Electrification Load scenarios. If load levels are higher than projected, or investment in energy efficiency does not meet projections, the costs of achieving the 100% Zero Carbon Target under all of the scenarios in Objective 1 will increase as Connecticut will need to procure more grid-scale zero carbon resources to meet the higher load.

Energy efficiency will be increasingly important in a future that looks like the modeled Electrification case described in Objective 1. To meet its broader, economy-wide greenhouse gas reduction goals, Connecticut must reduce emissions from the building sector. With approximately 45 percent of Connecticut's housing stock still relying on oil or propane for space heating, electrification through technologies like high efficiency air source heat pumps (ASHPs), geothermal heat pumps, and solar space and water heating are becoming increasingly important. However, as this heating load historically met with fossil fuels converts to electric, electricity demand will increase, as reflected in the modeled Electrification Load scenarios. Furthermore, as Connecticut electrifies its transportation sector, vehicle charging load must be encouraged to off-peak hours and, ideally, responsive to dynamic pricing in order to prevent increased costs to the grid. Energy efficiency and demand response will remain a central and dynamic component of modern grid planning to minimize both the amount of energy needed to achieve a cost-effective, decarbonized future and some of the transmission upgrades needed support it.

Dynamic Approaches to Energy Efficiency Program Oversight and Maintenance of Program Funding

Recognizing these priorities, DEEP, with significant stakeholder input, has directed considerable changes and improvements to the C&LM Plan programs in the 2020 program year, and has identified key priorities

[241] Public Act 17-2, Section 683, An Act Concerning the State Budget for the Biennium Ending June 30, 2019, Making Appropriations Therefore, Authorizing and Adjusting Bonds of the State and Implementing Provision of the Budget.

for the 2021 program year and for the next three-year plan, which begins in 2022. Oversight of the C&LM Plan requires responsiveness and adaptability in order to continually incorporate lessons learned and best practices in an extremely dynamic field. The three-year planning cycle is valuable insofar as it allows for annual budget flexibility and planning for longer-term issues, such as developing a schedule for evaluations. However, DEEP has taken a much more proactive approach in 2020, in collaboration with the EEB, program administrators, vendors, and other stakeholders, to increase feedback processes and provide decisions modifying the plans as needed, rather than waiting for the next three-year planning process.

In DEEP's Conditions of Approval for the 2020 Plan Update (Conditions of Approval), issued in February 2020, DEEP directed the utility C&LM program administrators, Eversource Energy, The United Illuminating Company, Connecticut Natural Gas Corporation, and Southern Connecticut Gas (together, the "Utilities"), to implement significant reforms to the programs and incentive levels by July, 2020.[242] These initial reforms were intended to align with industry best practices, to provide increased greenhouse gas reductions, and to make the programs more equitable and accessible by reducing or, in some cases, eliminating up-front costs. The reforms included expanding the program benefits in the benefit cost calculation to include oil and propane thermal savings; increases to insulation and heat pump incentives; streamlining of eligibility processes for customers with low income, including using census tract data to determine eligibility and creating a more streamlined application for renters; focusing on heat pump conversions for customers with inefficient and expensive electric resistance heat; and conducting outreach to homeowners with crumbling foundations for building envelope and heat pump programs.[243]

Prior to the EDCs' implementation of the changes required in the Conditions of Approval, COVID-19 struck Connecticut, leading to a temporary shutdown of on-site work for the residential and small business programs.[244] DEEP led an intensive, collaborative engagement effort including the EDCs, the EEB, the vendor community, and other stakeholders, and issued multiple DEEP determinations focused on improving vendor cash flow and preparing for a return to on-site work.[245] Governor Lamont's administration provided significant industry support, with the Office of the Governor, the Department of

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[242] *See* DEEP Approval of 2020 C&LM Plan Update, Appendix A, February 11, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/16d2e80a4a780ab78525850b0057ec6a/$FILE/Approval%20of%20CLM%202020%20Plan%20Update.pdf.

[243] *See id.*

[244] *See* Conn. Energy Efficiency Programs COVID-19 Contingency Planning Letter, March 17, 2020, at pg. 1, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/8525797c00471adb8525852e006762b3/$FILE/Connecticut%20Energy%20Efficiency%20Programs%20COVID19%20Contingency%20Planning%2003172020%20Final%20Draft%20(002).pdf.

[245] *See* DEEP's Initial Action Regarding COVID-19 Contingency Planning, March 27, 2020; DEEP's Approval of Virtual Pre-Assessment Proposal, April 24, 2020; DEEP's Approval of Administrative Fee Proposal, April 24, 2020; DEEP's Approval of SBEA Incentives, May 23, 2020; DEEP's Final Determination and Health and Safety Protocols, June 11, 2020; DEEP's Determination Regarding SBEA Eligibility Modifications, July 15, 2020, *all available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=6.5&Seq=43. *See also* DEEP's Determination Regarding COVID-19 Related Compliance Items, May 18, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/7a46c7415ba02f088525856c007a0de2/$FILE/DEEP%20Determination%20Re%20March%202020%20Compliance%20Items%20-%20COVID%20Related.pdf.

Economic and Community Development, and DEEP collaborating with the Connecticut Green Bank and the EDCs' to provide remote seminars to clean energy contractors on available programs such as the Paycheck Protection Program and updates on unemployment insurance, and to conduct a recurring survey to measure the impacts of the pandemic on Connecticut's clean energy industry. As that work was underway, further collaboration led to DEEP's issuance of Health and Safety Protocols allowing the safe return to on-site work, along with increased incentives to help jump-start program activity and provide economic relief and stimulus to customers.[246] This dynamic approach in response to the impacts of the pandemic helped stabilize the energy efficiency industry in Connecticut.

The COVID-19 pandemic was not the first challenge to the stability of the C&LM programs and the workforce the programs support. Public Act 17-2, as amended by Public Act 18-81, diverted a total of $117 million of electric efficiency funding over three budget years (2017-2019) into the general fund.[247] The biggest impact occurred in 2018, with a reduction in the budget of 32 percent, and a 38 percent reduction of the electric savings Connecticut relies upon to avoid the cost of additional generation, transmission and distribution. Just as the C&LM programs and contractors were beginning to recover, COVID-19 caused further instability. In order to continue on the path to industry stability, achieve the energy savings Connecticut relies upon from the C&LM programs, reduce customer bills, and reduce harmful emissions, it is critical to ensure that the C&LM programs are protected from being diverted for other purposes.

Equitable Energy Efficiency

All electric and natural gas ratepayers contribute to the C&LM Plan funds through a charge on their bills. It is therefore imperative to ensure that all ratepayers are able to participate in the C&LM programs. Barriers to accessibility and affordability must be identified and addressed to ensure that customers who have been historically underserved can benefit from the programs. To address concerns surrounding program affordability, DEEP issued several determinations throughout 2020 that focused on expanding program access by reducing or eliminating up-front costs.[248] For instance, DEEP issued an Approval with Conditions of the 2020 C&LM Plan Update, which improved upon and streamlined eligibility requirements for limited-income program participation.[249] In 2020, DEEP also released multiple determinations

[246] *See* DEEP's Final Determination and Health and Safety Protocols, June 11, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/8b4f54e48303b48785258584006afccf?OpenDocument.

[247] Public Act 17-2, Section 683, An Act Concerning the State Budget for the Biennium Ending June 30, 2019, Making Appropriations Therefore, Authorizing and Adjusting Bonds of the State and Implementing Provision of the Budget; Public Act 18-81, Section 12, An Act Concerning Revisions to the State Budget for Fiscal Year 2019 and Deficiency Appropriations for Fiscal Year 2018.

[248] *See* DEEP Determination Regarding COVID Related Compliance Items, May 18, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/dcc3b63fe3bad459852585a60039c8c8?OpenDocument(temporarily waiving the HES co-pay and increasing several incentives offered in residential programs); DEEP Approval of SBEA Incentives, May 22, 2020 *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/fc98d76d7471d27b85258571005f8099/$FILE/22%20May%202020%20-%20DEEP%20Approval%20SBEA%20incentives.pdf (temporarily increasing incentives offered in C&I programs).

[249] *See* DEEP Approval of 2020 C&LM Plan Update, Appendix A, February 11, 2020, pg. 1, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/16d2e80a4a780ab78525850b0057ec6a/$FILE/Approval%20of%20CLM%202020%20Plan%20Update.pdf.

increasing C&LM program incentives and minimizing or eliminating upfront costs for customers with low and moderate income, and continues this work moving into the planning cycle for the next three-year plan.[250]

Despite these efforts, access to the C&LM programs is still difficult for those who rent their homes and those whose homes have health and safety barriers that require remediation prior to the installation of efficiency measures, such as asbestos, mold, or lead paint. Moreover, the utilities currently do not track program participation by demographics such as race, ethnicity, or primary language spoken. DEEP therefore recently launched an Equitable Energy Efficiency Proceeding, to identify barriers to equitable participation in energy efficiency programs and pathways to address those barriers, and to develop metrics for defining equity and measuring program outcomes from an equity perspective.[251] The Department will also gather information regarding methods for more inclusive outreach to those who have faced challenges to program participation such as residents with low and moderate income, businesses in underserved communities, renters, and those who live in homes or own businesses with health and safety barriers.[252]

The Department recognizes that significant opportunity exists to collaborate with municipalities and established community organizations to aggregate both residential and business customers for participation in the various C&LM program offerings and to help tailor programs to the particular needs of communities. The Department will also explore best practices from other states regarding community engagement strategies.

Planning for the Future

In 2021, the C&LM Plan is entering a planning year in its three-year planning cycle. The Department is also preparing to launch the process for the next Comprehensive Energy Strategy, which will focus on decarbonizing the building sector. At the same time, decisions are expected in PURA's Equitable Modern Grid proceedings[253] regarding statewide AMI rollout, innovative rate designs, and other advances that will help unlock benefits associated with and better enable innovative approaches to energy efficiency and demand response. Through its C&LM and CES planning processes, DEEP will work with the EEB, the utility program administrators, and stakeholders, to leverage those technological advances to ensure the C&LM

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[250] *See* DEEP's Approval of SBEA Incentives, May 22, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/fc98d76d7471d27b85258571005f8099/$FILE/22%20May%202020%20-%20DEEP%20Approval%20SBEA%20incentives.pdf; DEEP's Determination Regarding SBEA Eligibility Modifications, July 15, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/dcc3b63fe3bad459852585a60039c8c8?OpenDocument; DEEP's Determination Regarding COVID-19 Related Compliance Items, May 18, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/7a46c7415ba02f088525856c007a0de2/$FILE/DEEP%20Determination%20Re%20March%202020%20Compliance%20Items%20-%20COVID%20Related.pdf.

[251] *See* DEEP's Notice of Equitable Energy Efficiency Proceeding and Request for Written Comments, September 3, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/12c36ce3c4b5a80c852585d80046845f?OpenDocument.

[252] *See id.*

[253] PURA Docket 17-12-03RE02, Docket 17-12-03RE11

programs are maximizing benefits for the grid and for participating ratepayers. The Department will explore approaches such as pay-for-performance and the expansion of active demand response and bring your own device programs.

As Connecticut moves toward a modernized grid, significant opportunities exist to help customers interact with the grid to manage their energy use. Whole-building approaches that integrate efficiency and demand response with distributed energy resources will help maximize the benefits of all of these resources. Connecticut currently recognizes this potential in the administration of the RSIP program, requiring that participants receive an energy audit to become eligible for the program incentives.[254] This structure ensures that customers can increase the cost-effectiveness of installing rooftop solar by minimizing their energy usage, and thereby reducing the size of the array needed to meet their load. For low- to moderate- income customers, the Green Bank partners with PosiGen to provide a solar lease program that pairs with energy efficiency measures to maximize energy cost savings for participants.[255] The Green Bank supports these integrated approaches by providing programs that finance a comprehensive set of energy technologies.[256] The Smart-E program is designed for residential customers, and the Commercial Property Assessed Clean Energy (C-PACE) program is available to commercial, industrial, multifamily and nonprofit property owners. Further integration potential exists for active demand response, including through battery storage, to help customers manage their load and also offer potential resilience benefits to participating customers, as further discussed below.

Demand Response and Storage

Energy efficiency helps to reduce overall electric load and therefore the necessary capacity needed to meet that load. However, as the State and region increase the amount of variable energy resources needed to meet emissions targets and replace traditional base load dispatchable resources, storage and active demand response (ADR) are needed to balance out the electric grid for resource adequacy. In this IRP, modeled storage resource selections are lithium-ion batteries, while active demand response refers to the ISO-NE definition of a "demand resource that reduces load in response to a request from ISO-NE to do so for reliability reasons, or in response to a price signal."[257] Demand side management refers to programs or policies that encourage electricity users to modify their energy consumption patterns in response to incentives like price signals.

Power generated on the grid must always equal demand for a reliable system, but periods of peak customer demand will often fail to match periods of peak production from variable zero carbon resources. If variable zero carbon resources alone cannot produce enough energy to cover customer demand, then storage resources can be deployed to supplement generation, while ADR and DSM can reduce or shift demand. These resources can help maintain reliability while reducing reliance on expensive peaking fossil-generating resources. Alternatively, if variable zero carbon resources produce more energy than demand requires, then generation from these resources must be limited or curtailed. The curtailment analysis provided in Appendix A3 highlights that a significant amount of renewable generation is curtailed due to export constraints in Southeastern Massachusetts and Rhode Island (SEMA/RI) and Northern New

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[254] *See* CT Green Bank, Legislative Report on the CT Green Bank Residential Solar Incentive Program, January 11, 2019, pg. 12, *available at* https://www.ctgreenbank.com/wp-content/uploads/2019/01/RSIP-Legislative-Report-2019.pdf.
[255] *See id.* at 6.
[256] *See id.* at 10.
[257] *See* ISO-NE, Glossary and Acronyms, *available at* https://www.iso-ne.com/participate/support/glossary-acronyms.

England. Approximately 4.1 TWh of variable energy generation, equivalent to 6.8 percent of grid-scale wind and solar capability, is curtailed in 2040 in the Base Load Balanced Blend scenario. Similarly, 9.2 TWh of variable energy generation, equivalent to 11.6 percent of grid-scale wind and solar capability, is curtailed in 2040 in the Electrification Load Balanced Blend scenario. Land-based wind in Northern New England, Maine in particular, has the most curtailments as a portion of nameplate capability. While transmission upgrades are one important step needed to mitigate curtailment, in some cases this can also be achieved with non-wires-alternatives, including storage resources collocated with renewable generation or at constrained transmission points. Alternatively, demand side management programs can move demand to higher variable supply periods, such as during midday solar peak, thereby also serving as a kind of storage.

The penetration of variable energy sources requires increased operating reserve capacity due to the greater forecasting errors associated with these generation methods. Both storage and active demand response can play an important role in meeting additional operating reserve capacity. For example, if wind or solar production falls unexpectedly, the storage and active demand response can act as reserve generation and take up the slack in the system until the variable zero carbon resources return to their forecasted output. The modeling indicates there will be a need for significant new operating reserve capacity due to the increased penetration of variable energy resources, with an additional 4,775 annual average megawatts (MWas) needed under the Base Balanced Blend scenario in 2040 and 5,270 MWas under the Electrification Balanced Blend scenario across the region. See Appendix A3 for further detail on operating reserves.

Storage and active demand response play a key role in fulfilling this additional operating reserve capacity required to meet our zero carbon goals. At the beginning of the study period, all scenarios have similar operating reserve makeups based on the type of unit providing the services. For example, in the Base Load Reference scenario, for products that require spinning/operating reserves (i.e., capable of near-instant response), about half of the requirements are provided by hydro and pumped storage resources and the other half is mostly provided by combined-cycle resources. Non-spinning reserve products (i.e., those that cannot immediately provide reliability services) are supplied predominately by combustion turbines. By 2040, however, as decarbonization policies advance, the modeling indicates that battery resources will displace a significant share of spinning reserve supply from combined-cycle resources and provides a significant portion of non-spinning requirements as well. Active demand response capacity also increases for operating reserve supply, but at a lesser amount than battery storage.

With active demand response, demand can be moved to different periods of the day by having customers reduce or curtail their demand during these peak (or otherwise limited) periods. This reduction or curtailment in turn reduces the demand on the system and avoids the need to run more expensive, carbon-intensive power plants, or in the most extreme cases, the possibility of rolling blackouts during these events. In the draft Value of DER study, DEEP and PURA found that the value of BTM solar PV increases when paired with electric storage.[258] This is primarily driven by the increased amount of capacity demand reduction induced price effect (DRIPE) that occurs when the two technologies are paired, relative to BTM solar PV alone.[259] The value of DRIPE is derived from the change in the capacity market (FCM) clearing price caused by the addition from a resource. In the case of BTM solar PV plus storage, demand

[258] *See* DEEP and PURA, Value of Distributed Energy Resources in Connecticut Study, July 1, 2020, at pg. 10, PURA Docket No. 19-06-29.
[259] *See* ISO-NE, Glossary and Acronyms, *available at* https://www.iso-ne.com/participate/support/glossary-acronyms.

from the grid can be offset in more hours than if only BTM solar PV was available. This effect is demonstrated by UC3 (i.e. "Use Case 3- BTM Solar PV Paired with Electric Storage" from the draft Value of DER study) in Figure 2.9 in Objective 2 above.

One of the key priorities of the C&LM Plan is to implement effective demand reduction strategies, as this can help reduce energy prices and price spikes during summer and winter peak demand.[260] While energy efficiency programs provide passive demand reduction, the Plan continues to evolve programs that provide active demand response.[261] In 2020, several demand response pilot programs have transitioned to full-fledged programs.[262] The 2020 Plan has a goal of 39.8 MW load reduction from demand response.[263] The programs target a variety of residential and commercial customers and include demand reduction strategies that are technology agnostic.[264] Different technologies are suited to different dispatch strategies.[265] Commercial and industrial programs are being designed around targeted dispatch, daily dispatch and winter peak demand.[266] Certain technologies, such as batteries and thermal storage can reduce load on a daily basis without impacting customer comfort or operations.[267] As Connecticut moves toward building and vehicle electrification, strategies can be developed to include these markets in demand reduction programs to help mitigate their impact on peak. For example, EV charging load is expected to increase and is seen as a load with the flexibility needed to be part of a demand response offering. Research suggests that 80 percent of charging is done at residences and may be generally coincident with system peaks if not managed or incented to occur in off-peak hours.[268]

Not limited solely to summer peak demand reductions, the demand response programs can also be useful for ramping (ISO-NE dispatch only), load curtailment, distribution system operational needs and shortage events, as well as winter demand reduction needs.[269] Demand response can also be applied in natural gas programs, which can provide electric sector benefits in the form of fuel security during peak days in the winter months while Connecticut relies on natural gas electric generation. Automation and advances in technology make it possible to manage customer loads in new ways with strategies that bring additional values to the utilities and the customer.[270]

Leveraging and Developing the Clean Energy Workforce

Through the C&LM program and the clean energy programs supported by the Green Bank, Connecticut has an existing network of skilled energy efficiency and renewable energy contractors and vendors who

[260] *See* 2019-2021 Conservation and Load Management Plan, November 19, 2018, at pgs. 89, 149, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/8525797c00471adb8525834a005f8ce2?OpenDocument.
[261] *See id.*
[262] *See* 2020 C&LM Plan Update, November 1, 2019, at pg. 15, *available at* https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Final-2020-Plan-Update-Text-11-1-19.pdf?la=en&hash=CABA7269C026532212943AF4C2F710BD.
[263] *See id.* at 91.
[264] *See id.* at 8.
[265] *See id.* at 21.
[266] *See id.*
[267] *See id.*
[268] *See id.* at 16.
[269] *See* 2019-2021 Conservation and Load Management Plan, at pg. 89.
[270] *See id.*

have served residential and business customers, municipalities, and community organizations throughout the state. Clean energy jobs accounted for 2.6 percent of total jobs in Connecticut at the end of 2019, and 80 percent of those jobs are in energy efficiency.[271] There is a need for workforce development in a variety of areas, which will provide more skilled jobs to contribute to Connecticut's economic recovery. Connecticut is well positioned to leverage and build on this existing workforce to provide holistic and equitable approaches for Connecticut's residential and business utility customers to interact with a modernized grid.

Strategies to Achieve Objective 5

Whether through market reform or ongoing procurements by Connecticut and neighboring states, New England can expect the amount of variable energy resource capacity to increase significantly over the next twenty years as states strive to meet their climate goals. The existing transmission system must evolve to support these resources. As discussed in Objective 5, current transmission planning has considered interconnection of these resources only, rather than full integration of wind resources' total nameplate capacity. This IRP recommends pursuing the following strategies in furtherance of Objective 5, Transmission Upgrades & Integration of Variable and Distributed Energy Resources. It is critical that Connecticut coordinates with the other New England states to evaluate transmission needs to meet state climate and energy policy goals (Strategy 4). To accomplish this, the state will also need to determine if the FERC Order 1000 public policy transmission planning process, or an alternative, is needed in the near future.

While upgrading the region's transmission infrastructure to accommodate an influx of variable energy resources in the future is necessary, there are additional measures Connecticut can deploy to reduce and balance loads such as energy efficiency, demand response, and energy storage resources. This IRP recommends that DEEP be given additional statutory authority to procure energy efficiency and active demand response programs, to leverage the ability of these resources to balance intermittent loads as we move toward the 100% Zero Carbon Target (Strategy 12). This IRP further recommends the following focus for the existing C&LM programs:

- Continue the Equitable Energy Efficiency process and the Health and Safety Barriers Working Group in partnership with the EEB to identify and address barriers to participation in energy efficiency programs.
- Continue to identify and implement best practices and innovative approaches, in alignment with PURA's Equitable Modern Grid proceedings, to transform the C&LM plan to integrate intermittent resources and promote a smart, interactive, equitable grid.
- Further update the cost-benefit test, and reevaluate the approach used in the regional avoided cost study utilized by the Utilities to evaluate programs and measures.
- Restructure the Utilities' performance incentives to align with specific program goals and metrics.

The Department will also coordinate with DECD and its Office of Workforce Strategy as well as other stakeholders to develop a strategic approach to clean energy workforce development for Connecticut in order to support a continued and robust clean energy industry (Strategy 9).

[271] *See* CT Green Bank, Connecticut Clean Energy Report, September 2020, at pgs. 4-5, *available at* https://ctgreenbank.com/wp-content/uploads/2020/11/2020-Connecticut-Clean-Energy-Industry-Report.pdf.

Objective 6: Balancing Decarbonization and Other Public Policy Goals

Reducing greenhouse gas emissions from the electric sector towards achievement of the GWSA goals is a key focus of this IRP.[272] So, too, is ensuring that electric supply meets other policy goals and standards, reflected in the state's RPS. Connecticut's RPS predates the GWSA, and includes among its objectives not only reducing GHG emissions, but also supporting fuel diversity, reducing dependence on fossil fuels, creating a hedge against volatile oil and natural gas commodity prices, lowering air emissions, promoting clean energy jobs and economic development,[273] and supporting certain technologies for managing Connecticut's waste disposal needs. In evaluating pathways to reach a 100% Zero Carbon Target for electric supply by 2040, the IRP recognizes the need for strategies that gradually harmonize the state's decarbonization efforts with the broad public policy goals of the RPS and other state policy goals. This IRP focuses on near-term issues and opportunities for four technologies included in the RPS: anaerobic digestion, WTE facilities, and biomass.

Waste-to-Energy Facilities

Connecticut produces over two million tons of municipal solid waste (MSW) annually, over 80 percent of which is disposed at Connecticut's five active WTE plants. The result of this high reliance on WTE is a reduction in methane and transportation-related emissions associated with landfilling. The State's policy in minimizing landfilling is set by Connecticut General Statutes Section 22a-228(b) and is consistent with the Environmental Protection Agency (EPA)'s waste management hierarchy for preferred waste management practices. Despite the benefit provided relative to not landfilling MSW, these plants, which represent about 198 MW of nameplate capacity, are estimated to produce roughly 800,000 tons of CO_2 annually as detailed in Appendix A3. They are also significant sources of NO_x and SO_2 emissions. As demonstrated by Table 4.2 in Objective 4, locations of the largest plants in communities with at-risk and minority populations raises public health and environmental justice concerns.

While these resources have high at-the-stack emissions intensities, their continued operation provides important waste disposal capacity and stabilizes costs for municipalities while Connecticut and its local governments seek a transition to more sustainable materials management strategies. Thus, this IRP removed WTE resources from the list of resources that are eligible to retire during the modeling period. Additionally, in order to maintain transparency in the carbon accounting for each model run, DEEP has included emissions from WTE units in the 2040 Regional Emissions Target. However, DEEP recognizes that in an ideal carbon accounting methodology, Connecticut cannot, for convenience, attribute emissions associated with WTE plants in Connecticut to other states. If those resources continue operating in 2040 and Connecticut purchases the RECs from those facilities, then generated emissions will need to be offset by additional zero carbon energy purchases beyond what is modeled in this IRP or offset in some other way.

In addition to carbon dioxide emissions, WTE plants located in the State produce significant NO_x and SO_2 emissions. Because these resources are designated as "must-run" for purposes other than reliability, they cannot be displaced by other zero carbon resources. Thus, the amount of NO_x and SO_2 can only diminish so much, as demonstrated in Table 6.1 and Figure 6.1 below. Accounting for these

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[272] *See* Conn. Gen. Stat. Section 16a-3a(a).

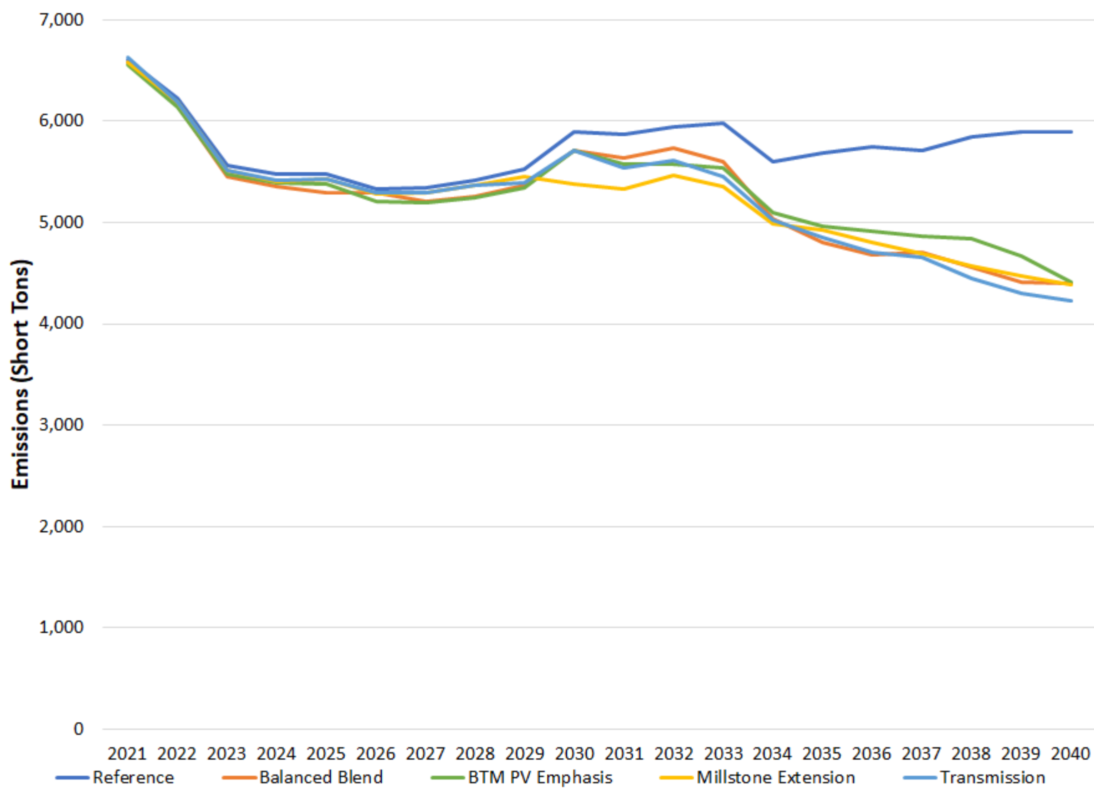
[273] CT DEEP RPS Study (2013), page 4, http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/67d62db9c92d7f6885257b320066e509/$FILE/RPS%20Restructuring%20Executive%20Summary%20Final.pdf.

greenhouse gases in this way allows Connecticut to transparently account for the impacts its current waste management system has on other policy goals, such as reducing emissions from its electric sector. In future IRPs, DEEP will continue to assess the role of WTE in our solid waste management goals and whether other emerging technologies are needed to meet the 100% Zero Carbon Target for 2040. Additionally, DEEP will explore whether accounting for emissions at the point of generation is appropriate or whether life-cycle accounting is more appropriate for WTE facilities.

Table 6.1: Connecticut Annual SO_2 Emissions by Scenario
(Short Tons)

Scenario	*2025*	*2030*	*2035*	*2040*
Base Reference	1,350	1,386	1,162	1,208
Base Balanced Blend	1,348	1,367	1,115	1,069
Base BTM Solar Emphasis	1,348	1,367	1,121	1,098
Base Millstone Extension	1,349	1,374	1,120	1,079
Base Transmission	1350	1,377	1,128	1,064
Electrification Reference	1,336	1,372	1,152	1,189
Electrification Balanced Blend	1,335	1,359	1,123	1,068
Electrification BTM Solar Emphasis	1,330	1,351	1,115	1,064
Electrification Millstone Extension	1,335	1,362	1,109	1,082
Electrification Transmission	1,334	1,358	1,106	1,057

Figure 6.1: Connecticut NOx Emissions, Base Load Scenarios



Connecticut's Class II RPS energy resource classification was amended in 2017 to be exclusively limited to WTE facilities by Public Act 17-144. This Act also increased the amount of power the EDCs are required to purchase from Class II resources (or Class I) to four percent of load served by load serving entities rather than three percent beginning in 2018. Only WTE facilities permitted by DEEP are eligible for Class II RECs. Thus, the Class II RPS requirement is intended to provide support for resources critical to our State solid waste management goals and policy.

Table 6.2 below shows the estimated number of Class II RECs that will be available over the next decade based on projected WTE production. If Connecticut facilities do not produce enough to meet the Class II target, there could be a shortage that firms up the REC prices relative to the alternative compliance price (ACP), and could create an additional outlet for Class I surplus if Class I REC prices fall below the ACP.[274]

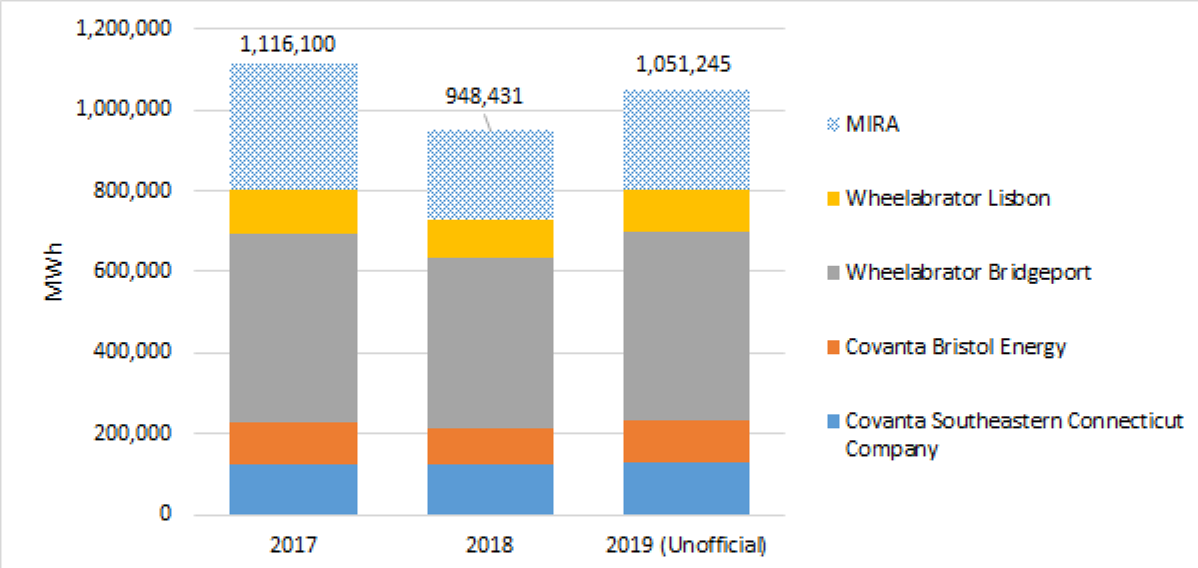
Table 6.2: Projected Class II RECs in Connecticut

Year	Class II MWhs
2020	1,010,280
2021	1,015,628
2022	1,025,419
2023	1,033,339
2024	1,044,240
2025	1,049,004
2026	1,056,311
2027	1,063,880
2028	1,074,898
2029	1,079,725

Currently, the five operating WTE facilities in Connecticut generate roughly 1,000 GWh of energy annually, as shown by Figure 6.2. If this level of generation is maintained, these facilities can continue to satisfy the requirements for the Class II RPS. However, there are factors that create uncertainty as to whether this is sustainable.

[274] Based on Regional Energy Market Outlook reporting provided by Sustainable Energy Advantage, LLC.

Figure 6.2: Annual Energy Generation from Connecticut Waste-to-Energy Facilities[275]



The Hartford Resource Recovery facility owned by the Materials Innovation and Recycling Authority (MIRA), the second largest WTE facility in the state, may be taken offline in coming years due to the poor condition of equipment and high costs to operate and maintain. In July of 2020, MIRA submitted its 2021 Annual Plan of Operations, stating that more than $300 million in electric ratepayer or taxpayer support would be needed for capital improvements to the facility, in the absence of which MIRA would convert the facility to a transfer station sending in-state generated MSW to landfills located out of state. MIRA's 2021 plan was rejected by DEEP as being incomplete and inconsistent with statute and State policy.

As shown in Figure 6.2, if the MIRA facility ceases operating, remaining WTE plants in Connecticut will only generate about 800 GWh of energy annually; just above 3 percent of eligible RPS load. Thus, at the time of drafting this IRP, the Class II structure is sufficient to support the output from the operating WTE facilities. The Department will continue to monitor MIRA's plans and the Class II market to determine if a restructuring is needed to maintain the current supply/demand balance equilibrium for Class II RECs depending on plant operations.

If the MIRA facility shuts down, it will cause the state to backtrack on its progress towards maintaining self-sufficient disposal capacity in the state, and will contribute to greater reliance on out-of-state landfills for disposal, in conflict with the state's waste hierarchy of preferred disposal options. For these reasons, it is important to consider policies, including energy policies, that can help states and municipalities adopt more sustainable materials management programs and policies that reduce reliance on disposal via WTE or landfilling. Such policies include measures that reduce or divert reusable material from the waste disposal stream, including recyclable paper, plastic, glass, and metal, and organic materials such as food scraps and yard waste which currently make up a significant portion of disposed municipal solid waste.

[275] U.S. Energy Information Administration. Form EIA-923 detailed data with pervious form data. https://www.eia.gov/electricity/data/eia923/

Note that like Connecticut, the State of Massachusetts provides for WTE facilities to receive ratepayer support through inclusion in the Massachusetts RPS. The level of REC subsidy provided to WTE facilities in Connecticut is substantially higher, on a MWh basis, than the REC subsidy provided for similar facilities in Massachusetts. Under Massachusetts' RPS structure, WTE facilities are required to reinvest 50% of REC revenues in Sustainable Materials Recovery Program that help to support disposal alternatives (such as local recycling, composting, reuse, source reduction, and enforcement activities) and limit overreliance on WTE over time.[276] These are positive practices that can ensure the RPS is not only helping to retain WTE facilities for reliable disposal in the near term, but preparing the state to reduce reliance on WTE and landfills in the medium- to long-term.

Anaerobic Digestion Facilities

According to a 2015 waste characterization study, approximately 22% of residential waste sent to disposal consists of food scraps, and an additional 11% consists of other organic material such as yard waste. If these materials can be diverted from waste disposal, they can provide a valuable feedstock for composting and anaerobic digestion facilities, while significantly reducing tonnage disposed at WTE (or landfills). Anaerobic digesters located on farms also provide benefits by using anaerobic digestion systems for manure management and can accept organic feedstocks from off-farm sources to generate revenue from tipping fees, while helping to divert organic material from disposal.

Anaerobic digesters are an important technology that will play a key a role in helping to manage the state's various waste needs, including reducing reliance on WTE and landfilling. While the state has only limited deployment of anaerobic digesters at present, it will be critical to support deployment of these facilities in accessible locations around the state to help minimize the cost of transporting diverted organic material to digesters. Anaerobic digesters produce compost material and biogas. The biogas can either be converted to electricity, or to renewable natural gas. Configuring anaerobic digesters to produce renewable natural gas can be preferable, given the possibility to utilize this fuel as compressed natural gas (CNG) for medium- and heavy-duty trucks, or to offset other uses of conventional natural gas. However, this opportunity can be limited by access to natural gas distribution systems and other infrastructure. Anaerobic digestion is eligible as a Class I renewable resource under Connecticut's RPS, and programs such as the virtual net metering program have been instrumental in supporting investment in the state's first large-scale anaerobic digestion facility in Southington. DEEP currently has authority to offer long-term energy and REC purchase agreements for anaerobic digestion, which will be critical for ensuring a build-out of needed digester facilities, but utilizing this authority requires anaerobic digesters to be configured to produce electricity. Securing companion authority to be able to offer such purchase agreements for the production of renewable natural gas would enable DEEP to support deployment of anaerobic digesters in configurations that match the needs of particular facility locations.

Biomass and Landfill Methane Gas Facilities

Legislation enacted in 2013 through Section 5 of Public Act 13-303 required DEEP to propose a schedule for gradually phasing down the value of Class I RECs produced by biomass and landfill methane gas (LMG) resources. The 2014 IRP recommended a gradual phase-down of REC values for Class I biomass and LMG beginning in 2018. The 2018 Comprehensive Energy Strategy reaffirmed DEEP's position to restructure the eligible Class I technologies to focus on the development of new, zero carbon

[276] *See* 310 CMR 19.300.

resources in New England and recommended initiating the phase-down of the REC value of biomass after the publication of the next IRP.[277]

At the time of Public Act 13-303, biomass made up the majority of the RECs settled for Class I compliance in Connecticut. In 2012, biomass made up over 80 percent and in 2013, biomass made up 65 percent.[278, 279] This is because even as the costs of zero-carbon resources continue to decline, resources like biomass are currently more lower-cost than other Class I eligible technologies, and RECs from biomass is therefore selected by energy suppliers to meet compliance first. In recent years, declining energy market revenues and other challenges have resulted in the closure of a number of biomass facilities, particularly in Northern New England, resulting in a shrinking, though still significant, portion of Class I RECs settled in Connecticut. The most recent PURA RPS decision for compliance year 2017 showed that biomass facilities currently account for approximately 45 percent of Connecticut's RPS, still more than any other technology.[280] Figure 6.3 shows the percentage of Class I RECs settled in Connecticut that come from biomass facilities has declined from 81 percent to 45 percent. Assuming prices traded at $40/REC in 2017, Connecticut's Class I RPS provided $73 million of ratepayer support to the biomass industry in that year alone.

While there are about 470 MWs of biomass generation throughout New England that are eligible for CT Class I RECs, most of the facilities are located out of state and do not support the forestry and waste management goals of Connecticut. Currently, the only in-state eligible biomass plant is Plainfield Renewable Energy, which has a nameplate capacity of 42 MW.281. Note that Public Act 13-303 exempts from any phase-down any facility that has a Connecticut ratepayer-backed power purchase agreement. Currently, facilities that meet that criterion are the Plainfield Renewable Energy plant in Plainfield,

[277] Given the low percentage of Class I RECs produced by LMG as compared to biomass, this IRP focuses on biomass, and a phase-down of LMG will be considered in the next IRP.

[278] Connecticut PURA. Docket No. 13-06-11. Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2012. February 11, 2015. *Available at:* http://www.dpuc.state.ct.us/DOCKHISTPost2000.NSF/8e6fc37a54110e3e852576190052b64d/8d0c8935f9117fe18525829c00735a7c?OpenDocument

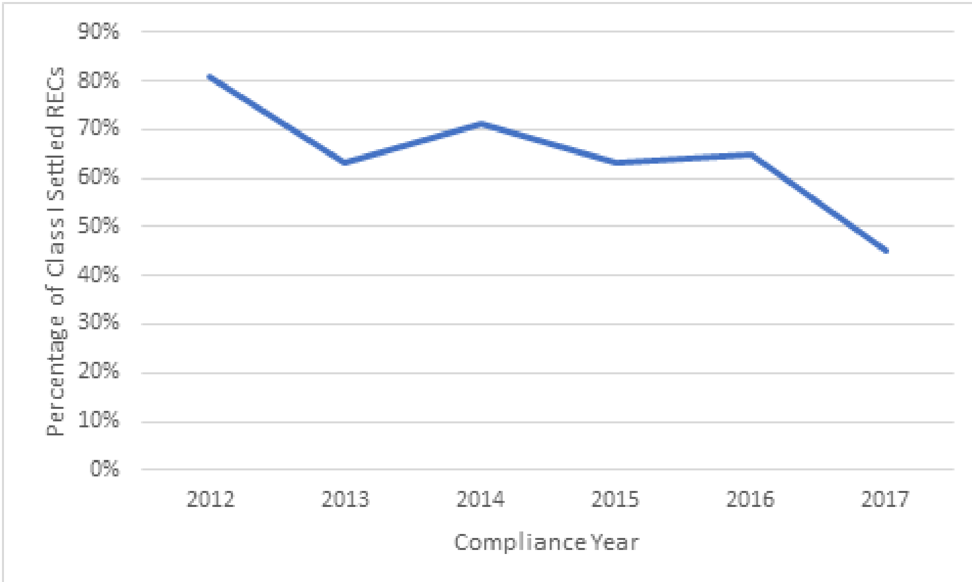
[279] Connecticut PURA. Docket No. 14-05-35. Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2013. December 23, 2015. *Available at:* http://www.dpuc.state.ct.us/DOCKHISTPost2000.NSF/8e6fc37a54110e3e852576190052b64d/7742091ba46d54c78525829c00724c72?OpenDocument

[280] Connecticut PURA. Docket No. 18-06-28 Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2017. July 1, 2020. *Available at:* http://www.dpuc.state.ct.us/DOCKCURR.NSF/0/211a83eea44855a885258598005ece70/$FILE/180628-062920.pdf

[281] ISO New England. 2019. 2019 Capacity, Energy, Loads and Transmission Report. Available at https://www.iso-ne.com/system-planning/system-plans-studies/celt

Connecticut, the Schiller Plant in Portsmouth, New Hampshire, and the Joseph C. McNeil plant in Burlington, Vermont.[282]

Figure 6.3: Percentage of Class I RECs Settled in Connecticut by Biomass



In support of this IRP, DEEP modeled the regional and Connecticut REC market, both with and without the biomass phasedown schedule articulated in the 2018 CES.[283] The purpose of this study was to estimate for each scenario:

- The theoretical potential for Connecticut Class I certified biomass/LMG to meet the State's Class I demand in each year from 2019 to 2040;
- How many Connecticut Class I eligible biomass/LMG RECs are expected to be generated annually through 2040;
- How many biomass/LMG RECs are expected to settle in Connecticut Class I; and
- The percentage of Connecticut Class I compliance that will come from biomass/LMG annually from 2020 to 2040.

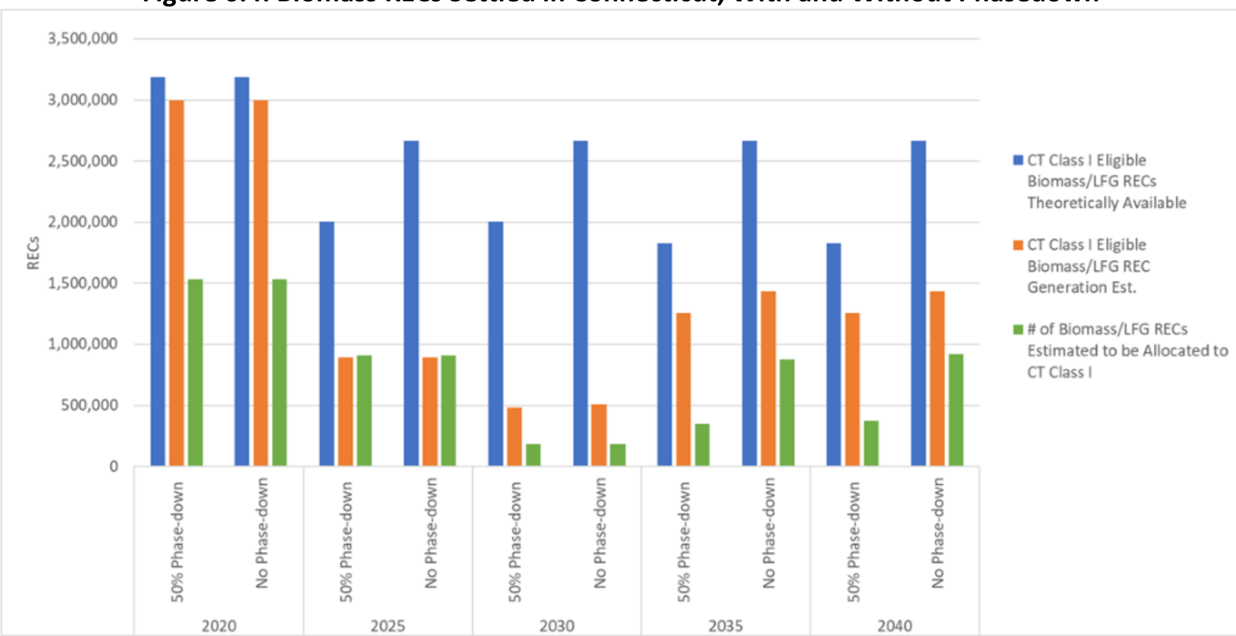
The Department relied on Sustainable Energy Advantage's (SEA) proprietary Renewable Energy Market Outlook (REMO) models for this analysis. These models consider supply, demand, and price dynamics throughout the six New England states and neighboring control area markets. The models estimated energy, capacity, and REC revenues for each eligible biomass generator, and compared those values to each generator's operating costs. In cases where costs exceeded revenues for extended periods of time, that plant's operation was assumed infeasible. Each scenario included the maximum theoretically available supply, and then estimated the supply actually expected to meet demand. It should be noted

[282] The Plainfield Renewable Energy Project has two different contracts. The first contract was entered into under the authorization of Section 124 of Public Act 07-242 and the second contract was entered into under the authorization of Section 3 of Public Act 18-50. The Schiller and McNeil contracts were entered into under the authorization of Section 8 of Public Act 13-303.
[283] This modeling was based on analysis provided under contract by Sustainable Energy Advantage, LLC.

that since this analysis was conducted in early 2020, policy decisions leading to biomass closures in mid-2020, policies related to imports from New York, and conditions caused by the COVID-19 pandemic are impacting near- and mid-term markets. Thus, there could be less participation from biomass facilities than was originally predicted by this analysis.

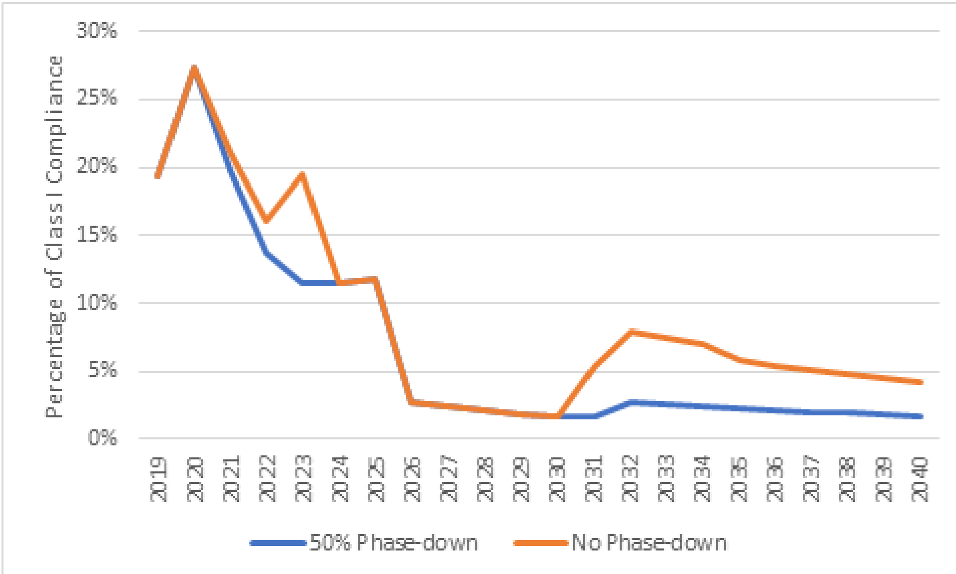
In absence of these recent changes, the analysis found that the biomass facilities projected to be settled in Connecticut decline over time both with and without the phasedown, though the phasedown results in slightly less biomass likely to be settled in Connecticut after 2030. In other words, the biomass phasedown has a small impact on biomass regionally as plants are projected to close down even absent Connecticut's phasedown. Figure 6.4 compares the Class I REC supply forecast with and without the biomass phase down, as articulated in the 2018 CES.

Figure 6.4: Biomass RECs Settled in Connecticut, With and Without Phasedown



In 2019, approximately 19 percent of the State's Class I REC requirement will have been met by biomass and LMG. In 2028, both with and without the phasedown, just 2 percent of the State's Class I REC requirement is projected to come from biomass and LMG. That 2 percent is projected to remain relatively constant through 2040 with the phasedown, and it is projected to increase slightly without the phasedown as Class I REC supply is needed to meet increasing demand and biomass facilities operate to fill the need. Figure 6.5 displays this trend.

Figure 6.5: Percentage of Connecticut Class I Compliance Met with Biomass and LMG RECs



Strategies to Achieve Objective 6

In Part II, the IRP recommends pursuing the following strategies in furtherance of Objective 6, Balancing Decarbonization and Other Public Policy Goals. The state has a wide variety of statutory environmental and other public policies that are reflected in electricity supply programs like the Renewable Portfolio Standard. By adopting a 100% Zero Carbon Target for 2040 (Strategy 1), the state will have the ability to engage in long-term planning and investment over the next twenty years to support a gradual transition and harmonization of decarbonization and other public policy objectives in a transparent and predictable way, such as seeking self-sufficiency in waste disposal options through development of more sustainable waste management approaches (Strategy 15). Consistent with recommendations in the 2018 Comprehensive Energy Strategy, this IRP also recommends phasing down the value of biomass RECS eligible for Connecticut's Class I RPS in order to increase participation from other eligible, zero-carbon resources (Strategy 14).

Part II: Strategies

Part I of the IRP examined in detail considerations for achieving six key objectives for Connecticut's electricity supply: (1) Decarbonizing the Electricity Sector, (2) Securing the Benefits of Competition & Minimizing Ratepayer Risk, (3) Ensuring Energy Affordability and Equity for all Ratepayers, (4) Optimal Siting of Generation Resources, (5) Transmission Upgrades & Integrating Variable and Distributed Energy Resources, (6) Balancing Decarbonization and Other Public Policy Goals. As noted in the summaries following each objective, Part II of the IRP now addresses strategies, emphasizing near-term actions for achieving those objectives. Because the objectives are interrelated, in many cases a single strategy advances multiple objectives. These strategies are detailed below, with the related objective(s) identified for each.

1. Adopt Legislation Enacting a 100% Zero Carbon Electric Supply Target for Connecticut

Objectives: 1, 3

Efforts at the international, national, regional, and local level to reduce and eventually eliminate the greenhouse gas emissions that are driving climate change must accelerate to keep up with the quickening pace of climate destabilization. The emergence of megafires, rapid loss of Arctic sea ice, degeneration of Antarctic glaciers and ice shelves, the growing number of superstorms, the increased prevalence and intensity of heat waves, the disproportionate negative effects on overburdened and underserved communities, and a lengthening list of other indicators signal the extraordinary urgency of rapidly decarbonizing the economy. As noted in Objective 1, these climate change impacts are already affecting Connecticut, and efforts to reduce carbon emissions in the near-term will be enormously cost-effective in terms of avoiding more costly climate change impacts, including reducing threats to human health and safety, in the longer term.

The state should adopt a statutory target of zero carbon emissions for the electricity grid by 2040 to ensure the grid's trajectory of significant GHG reductions will not only continue but accelerate over the next two decades. Decarbonization of the electric sector is the linchpin of a multi-sector decarbonization strategy that includes the electrification of transportation and heating, to the extent that reducing the emission content of electric "fuel" for buildings and transportation uses also improves the emissions reduction associated with electrification. Technologies for decarbonization of the electric sector are widely available, and the costs of the technologies are declining. Moreover, a 2040 target—now two decades away--provides an important long-term signal to the market that will facilitate more efficient planning and investment over time. A statutory 2040 target for a zero carbon electric supply would complement the Global Warming Solutions Act (GWSA), which already requires significant economy-wide reductions in the state, by providing more clarity about the expected reductions for the electric sector in achieving the broader GWSA goal. In essence, a 2040 target would provide Connecticut with more flexibility to allocate its dwindling 2050 emissions budget under the GWSA to economic sectors where decarbonization is more technically challenging: aviation, heavy-duty vehicles, industry, agriculture, and waste.

The modeling summarized in Objective 1 reveals that there are multiple pathways to achieving this goal, and that there are a variety of resources—distributed and grid-scale solar, hydropower, nuclear, land-based and offshore wind, as well as storage, efficiency, and demand response—that can be deployed in different combinations to meet the goal. One consistent finding was that Connecticut's existing clean energy procurements, distributed generation programs, and energy efficiency services have already put the state on a trajectory towards this goal. Other states and jurisdictions have similarly concluded that rapid electric sector decarbonization is feasible, such that 18 states, plus Washington D.C. and Puerto Rico, have already adopted similar targets, including eight states, plus Washington D.C. and Puerto Rico, that have enacted targets in statute.

The recommended strategies listed below all contribute towards meeting the 100% Zero Carbon Target, but can also be refined and leveraged to both increase cost-effectiveness and begin meaningfully addressing systemic inequities caused by reliance on fossil fuels. Any statutory target should highlight the importance of taking all appropriate measures to minimize costs and maximize equity. Future IRPs can closely monitor the State's progress toward meeting the 2040 goal and make recommendations for near-term actions to maintain that progress.

Connecticut's municipal electric cooperatives serve approximately 6 percent of the state's electric supply. While municipal electric cooperatives are taking steps toward decarbonization, currently, they do not have reporting requirements tied to the GWSA, despite the fact that the GWSA applies statewide. CMEEC submitted comments in this IRP proceeding supporting providing reports to DEEP regarding its carbon reductions.[284] Enabling such reporting requirements would provide more complete information for DEEP, PURA, the EDCs, and the municipal electric cooperatives, to help all parties determine and coordinate the respective amount of investment required in the state's electric sector to meet the state's economy-wide targets.

2. Pursue Reform of Wholesale Electricity Markets

Objectives: 1, 2, 3, 5

As detailed extensively in Objective 2, Connecticut's participation in the regional wholesale electricity market constructs, as presently designed and implemented by ISO-NE, has become a significant barrier to cost-effective clean energy deployment strategies, while increasing regional reliance on natural gas to an extent that has threatened reliability. These barriers have, in turn, created complications for state jurisdictional clean energy programs, also detailed in Objective 2.

Connecticut must be assured that our clean energy resources will be valued, or "counted," in the ISO-NE capacity market, to avoid duplicative costs of conventional fossil generation—which, in the recent past, has often been targeted for development in our state. We must be assured that the ISO-NE's market design, transmission planning, and system operation also value Connecticut's investments in clean energy generation, including behind-the-meter resources, to ensure that those resources are operated efficiently, complemented by zero-carbon balancing resources like storage and demand response, and that spillage or curtailment is minimized. Finally, Connecticut deserves a market that equitably shares the costs of retaining resources, like Millstone, that provide regional reliability benefits.

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[284] *See* CMEEC Written Comments, submitted October 29, 2019. http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/51c7b27775ac0827852584a8005e43e8/$FILE/Ltr%20DEEP_IRP%20Comments_10-29-2019.pdf

The barriers presented by the ISO-NE's current market design are not a reason to abandon competition, or the efficiencies provided by a regional grid. Exiting the ISO-NE market by taking back resource adequacy is an option that cannot be counted out, but the state's first priority must be to advance new regional market designs, in collaboration with the other New England states, that can recapture the benefits of regional, competitive market designs that achieve the states' respective public policy goals. A "unified" market design that achieves public policy goals will provide lower cost decarbonization more effectively.

For this reason, Connecticut DEEP has prioritized collaboration with the other New England states to secure changes to the wholesale markets. On October 14, 2020, Governor Lamont was joined by the Governors of Massachusetts, Maine, Rhode Island, and Vermont in a statement calling for a clean, affordable, and reliable regional electric grid that employs transparent decision-making processes and relies on competitive market outcomes to fully support clean energy laws. Among other things, the Statement and an accompanying Vision Statement issued by the New England States Committee on Electricity (NESCOE) calls for reforms to the regional wholesale markets by pursuing a new, regionally-based market framework that adheres to certain bedrock principles. Key among these principles is the requirement that any new market framework must use market-based mechanisms to meet the states' decarbonization mandates and maintain resource adequacy at the lowest cost to ratepayers. Just as important, a reformed market framework must include effective mechanisms that will fully accommodate existing and future long-term contracts for clean energy resources executed pursuant to state law. These two principles help to ensure that Connecticut's state-sponsored resources will be appropriately recognized and compensated in the regional market, thereby ensuring that Connecticut can reach its greenhouse gas reductions mandates from the electric sector at the lowest possible cost.

The Vision Statement indicates that the states will convene technical meetings to engage with stakeholders on wholesale market design options that can achieve the desired principles. These technical meetings will be convened in early 2021, during the comment period for this IRP. Among the potential market designs that may be considered is a Forward Clean Energy Market (FCEM) and accompanying Integrated Clean Capacity Market (ICCM). The Department will update this strategy in the final IRP with any near-term actions that emerge from ongoing collaboration with the other New England States.

Finally, as noted in Objective 4, Connecticut hosts a disproportionate share of the region's fossil fuel generation capacity, and much of that investment has been driven in recent years by a capacity market framework that has imbedded preferences for natural gas resources, despite claims of resource neutrality by the ISO-NE. The capacity market design fundamentally favors generation with low fixed costs and high variable costs such as natural gas over generation that has higher fixed costs and lower variable costs, such as wind and solar. This discriminatory framework has favored the selection of natural gas resources in the ISO-NE capacity market and deepened the reliability risks associated with the region's natural gas dependence.

It is also important to note that in legislation enacted in September 2020, the Connecticut General Assembly has recognized the urgent need to address wholesale energy market reform, and directed DEEP to prepare a report evaluating whether Connecticut ratepayers benefit from Connecticut's reliance on wholesale energy markets administered by the ISO-NE and recommending alternative approaches for Connecticut to more effectively meet its need for clean, reliable, and affordable electricity generation supply that relies on competitive, reduces ratepayer risk, and ensures the State's public policy goals are achieved.[285] The Department intends to submit to the General Assembly the information detailed in Objective 2 in consideration of that requirement.

3. Reform Governance Structure Surrounding ISO-New England Markets

Objectives: 2, 3, 5

The ISO-New England's disregard for state policies and consumer impacts— detailed in Objective 2, above— may be a consequence of its governance structure, which lacks any accountability mechanism that would require ISO-NE to take actions that are consistent with states' policy objectives. Moreover, any new market design that emerges in response to Strategy 2 (above) to achieve state public policies must have appropriate involvement of state entities. Reforming governance structures is therefore an important near-term strategy that the State should pursue, through advocacy in the appropriate NEPOOL, FERC, or other venues, to achieve the State's energy supply Objectives.

At present, the ISO-NE governance processes fall short in providing a process that is accessible and transparent for ratepayers affected by ISO-NE's decisions. As detailed in the Vision Statement, ISO-NE board meetings are completely closed to the public. The only visibility that ratepayers or policymakers have into the decision-making process of the ISO-NE Board is through extremely high-level summaries provided by ISO-NE management and scant agendas released by the ISO-NE Board. Additionally, the states lack any real voice in determining the composition of the Board. Board members are selected through a Joint Nominating Committee. The six sovereign New England states get a single, shared vote in this committee. In contrast, up to seven incumbent Board members each get a vote and market participants and other stakeholder get up to six votes. Thus, all six New England states together get a combined 1/14th of the vote in nominating a new Board member.

Governance and process changes at ISO-NE that facilitate transparency and accountability to consumers will lead to better decision-making. Some near-term changes that could be considered include providing for ISO-NE Board meetings and NEPOOL stakeholder meetings to be conducted in an open and efficient manner. Governance changes should be aimed at recalibrating the roles of the New England states and ISO-NE with respect to resource adequacy to account for and accommodate the states' Federal Power Act authority to exercise control over the generation mix.

As state policies effect significant changes in the resource mix, there are increasing benefits from a collaborative partnership between states and the ISO-NE Board and management. States play critical roles in public policy resource selection, siting, and permitting, as well as (through utility commissions like PURA) in regulating investment in electric distribution systems, an increasingly critical role as BTM resources expand. A governance structure that enables greater collaboration between the states and ISO-NE will enhance the ISO-NE's ability to carry out its responsibilities to plan the transmission system, operate the electric grid, and design markets that are increasingly affected by state policies. Examples of governance changes that could enhance this collaboration include:

[285] Public Act 20-5, An Act Concerning Emergency Response by Electric Distribution Companies, The Regulations of other Public Utilities and Nexus Provisions for Certain Disaster-related or Emergency-related Work Performed in the State, § 14, September Special Session (2020).

- Requiring the ISO-NE, in developing market and rule changes, to assess the impact of any change on the achievement of state policy objectives; where ISO-NE concludes that a proposed change will have a negative impact, prepare and publish a cost-benefit analysis demonstrating that the value of the anticipated benefits exceed the negative impact the change is anticipated to have on state pursuit of environmental objectives; and
- Adoption by the ISO-NE Board of Directors of the obligation to: (1) consider state alternatives to any ISO-NE rule changes; and (2) in those instances in which state alternatives are not adopted, provide a response to the States, explaining the bases for the Board's rejection and any cost-benefit or other studies justifying the Board's action.

The Vision Statement notes that the states will convene technical meetings to engage with stakeholders on governance reform; these meetings are expected to occur in early 2021. The technical meetings will be a place to further explore best practices and potential reforms that could be adopted to improve governance and transparency. The Department will participate in those technical meetings and reflect in the final version of the IRP any emerging strategies for governance reform that the state can advance in the near term.

4. Coordinate with regional states on evaluating transmission needs to meet state climate and energy policy goals

Objectives: 1, 2, 3, 5

As indicated in Objective 1, Connecticut will need 3,745 MWs of offshore wind resources and 352 MWs of land-based wind by 2040 to meet its zero carbon goals under the Base Load Balanced Blend scenario, and 5,710 MWs of offshore wind and 557 MWs of land-based wind under the Electrification Load Balanced Blend scenario. In total, the model projects that the region will need a maximum of 10,555 MWs of OSW under the Base Load, and 15,405 MWs under the Electrification Load by 2040. However, as discussed in Objective 5, the region's transmission infrastructure is unable to support the necessary OSW needed over the next two decades to meet the Regional Emissions Target. ISO-New England studies have revealed that, despite the substantial investment in the transmission system in recent years, it will be necessary to upgrade the system to affordably integrate these new resources.[15] In this context, "affordable integration" will mean both maximizing the VER interconnection capability of the grid, while minimizing the energy lost from zero carbon resources due to curtailment.

As demonstrated in Objective 5, upgrading the transmission system can significantly reduce curtailment of VERs over the next two decades. With reduced curtailment, less clean energy will be wasted, thus reducing any oversupply needed to meet reliability and emissions requirements. As a result, the modeling also shows that eliminating or reducing transmission constraints could also reduce the overall ratepayer costs of achieving the 100% Zero Carbon Target.

Under the current ISO-NE tariff, proactive planning is a challenge. To date the approach has been primarily reactive in that developers take a queue position on a first-come-first-served basis and are studied in order by ISO-NE planners. In order to address state policies, a scenario-based proactive planning process is needed.

Fortunately, the modeling results in Objective 1 reveal that New England currently has the convenience of time, as new OSW resources are not needed to come online until the early 2030s in many of the scenarios. Connecticut and the other New England states should take advantage of this time to set in motion comprehensive and advanced transmission planning that will enable a clean energy grid. The Department will collaborate with other New England states, particularly within the context of the work being done in furtherance of Objective 2 and Strategy 2, to address transmission challenges with increased variable energy resource penetration.

5. Monitor Conditions to Determine When to Conduct New Grid-Scale Renewable Procurements, including Offshore Wind

Objectives: 1, 2, 4, 5

Competitive procurements have been an effective tool to deploy the zero carbon resources needed to meet the State's climate goals at the least cost for all ratepayers, given the failure of the regional markets to support state policy goals, as discussed in more detail in Objective 2. With the continuing price declines in renewable technologies over the past decade, in the absence of meaningful regional market reform, DEEP is poised to capture clean energy at a just and reasonable price for all ratepayers using competitive procurements that result in long-term contracts for developers.

The modeling results indicate Connecticut has made significant progress towards securing zero-carbon resources to meet medium- and long-term GHG emissions goals, with approximately 90 percent of the state's load contracted to zero carbon resources (including nuclear, offshore wind, and solar) by 2025. This includes approximately 19 percent of the state's EDC load that will be under contract to offshore wind by 2025. As noted above, none of the modeling scenarios and assumptions detailed in Objective 1 are intended as preferred pathways for meeting the state's goals. Rather, they provide insights about the various contingencies that should inform the state's energy procurement strategy. This strategy discusses those contingencies and provides estimates of when procurements for grid-scale renewable resources should be initiated—including specifically, procurements for offshore wind.

It should be noted that when discussing below when resources are needed, this refers to the date that the resources are needed to be in operation. Given the lead times needed between procurement, project selection and when projects begin operation, the timing of a procurement would need to be some years earlier than when the resource is needed to perform.

Millstone

The Millstone nuclear facility is the largest generating unit in New England, and also the largest zero-carbon emitting generation facility in New England. As detailed above, the state reluctantly entered into a ten-year contract backed by Connecticut ratepayers to prevent the facility from shutting down before the end of its operating licenses (2035 for Millstone Unit 2, and 2045 for Millstone Unit 3), when no regional ISO-NE mechanism for retaining the resource was available, and after confirming that the facility was imminently at-risk of retirement. Connecticut's options in negotiating the contract were limited, but the alternative to contracting (retirement) was much more costly, both in terms of increased energy costs and GHG emissions. Preventing Millstone's retirement, among other things, prevented GHG emissions from increasing by 25 percent across the entire New England region. The costs of the contract are born entirely by Eversource and United Illuminating ratepayers.

With the ten-year contract in place, the State now has time to implement strategies that ensure that it has more zero-carbon options available by the contract's end—essential to prevent any exercise of market power and ensure competitive outcomes and minimize ratepayer risk. The modeling scenarios in Objective 1 reflect that the continued operation of the Millstone units beyond the end of current contracts (in 2029) would require the region to procure and integrate fewer MW of new renewable resources, and fewer MW of reserves (see Millstone Extension scenarios) to meet the regional emission reductions assumed in the model. Starting from that premise, ensuring that the Millstone units do not retire in 2029 becomes an important priority for reducing GHG emissions from the New England electric supply affordably and reliably.

At present, however, Connecticut's ratepayer-backed contract is the only mechanism in the region securing the continued operation of the Millstone resource. For this reason, the Millstone Extension scenarios assume that Connecticut continues to contract for, and count towards emission target compliance, the Millstone output. Under that scenario, the state has the least amount of new renewables and reserves to procure to meet the 2040 targets. No new zero carbon resources need to be online until 2029. But proceeding in this way, the state would be very dependent on a singular nuclear resource to meet its public policy goals, with fewer renewable alternatives available to enable competition and moderate any contract extension price, or ensure that goals could still be met if the facility ceased operating for any reason or length of time. Procuring sufficient clean energy resources in *advance* of 2029 to replace Millstone would be one way to avoid that problem.

The Balanced Blend scenarios provide a view of the quantities and potential cost of Millstone replacement. Given the "lumpiness" or large size of Millstone, it would be difficult to time the new clean energy additions to coincide perfectly with the end of the Millstone contract. Erring on the side of adding replacement clean energy *after* the contract terminates produces a risk of missing mid-term GHG emission targets. Erring on the side of adding replacement clean energy *before* the contract terminates places higher cost burdens on ratepayers. With approximately 90 percent of the state's EDC load already contracted, these are real concerns from a contracting capacity and ratepayer affordability perspective. For this reason, new clean energy additions in the Balanced Blend scenario begin in 2026 (Electrification Load case) or 2027 (Base Load case), and ramp up in the early 2030s, which causes the state to underperform in meeting the GC3's 2030 planning target for several years in the early 2030s.

These scenarios reflect a somewhat binary view, where Millstone's continued operation is solely dependent on a Connecticut ratepayer contract. An alternate path opens up if other states take on a share of the above market costs of Millstone through the purchase of environmental attributes currently claimed by Connecticut. Under that circumstance, new clean energy resources could be needed even sooner than 2026 or 2027.

Deployment of Existing Contracted Resources

Another key contingency in meeting the state's GHG emissions goals involves the deployment of projects that have already been procured, but not yet constructed. There are numerous milestones in project development, including permitting and siting approvals, financing, construction, interconnection and commissioning. The state has 2,400 MW of clean energy resources under contract that have not yet reached their commercial operation date. If those resources do not achieve commercial operation, or are significantly delayed in reaching commercial operation, an earlier procurement of replacement resources could be warranted to ensure continued progress towards the state's GHG emission targets.

Pace of Electrification of Thermal and Buildings Sectors

In 2018, the GC3 determined that Connecticut will need to achieve a 66 percent zero carbon electric supply by 2030 to meet the State's mid-term, economy-wide carbon reduction target (45 percent below 2001 levels by 2050) established in Public Act 18-82. This electric sector target was developed by assuming emissions-reduction targets of 34 percent in the buildings sector and 29 percent in the transportation sector, relative to a 2014 baseline. The modeling scenarios in Objective 1 reflect that 66 percent target for 2030. If reductions do not progress at those rates in buildings and transportation, an alternative way to achieve compliance with the mid-term target would be to accelerate reductions in the electric sector—necessitating more zero carbon resource deployment than is assumed in the modeling for this IRP.

Similarly, all of the modeling scenarios reflect the importance of monitoring the pace of electrification to determine procurement needs. Under the Electrification Load cases in each scenario, a greater quantity of new clean energy resources is needed to maintain progress towards the 2030 and 2040 emissions targets assumed in Objective 1.

Procurement-to-In-Service Lead Times

As noted above, it can take several years for a project that is selected in a procurement to achieve siting, permitting, financing, and construction of new generation facilities, such that procurements must occur several years in advance of the year when resources are needed. This procurement lead time must be factored into planning for new clean energy additions. For example, for offshore wind, the IRP estimates that approximately 5-6 years of lead time is needed from procurement award to commercial operation date. Grid-scale solar projects, by contract, may require half that time.

Declining Technology Costs

As noted in Objective 2, Connecticut has witnessed significant declines in the cost of renewable technologies such as solar. In the years since DEEP began utilizing competitive procurements for grid-scale solar, selected bid prices have declined from $333/MWh to $50/MWh, and the sequencing of those procurements over time has enabled the state to secure zero emission resources at increasingly lower costs, improving affordability for ratepayers. Spacing or sequencing of procurements is an important consideration in a procurement strategy for resources that are expected to see technology costs decline over time. With respect to offshore wind, for example, as turbine sizes increase and domestic supply chain and workforce development improve due to OSW procurements throughout the region, prices are expected to decrease over time. By contrast, project costs can also be affected by the sunset or extension of federal tax credits and other time-limited incentives. Therefore, it is important to carefully monitor technology cost, pricing results in other jurisdictions' RFPs, and incentive policy changes that could affect project pricing, and factor that into the timing of procurements.

Availability of Transmission Resources

Modeling results for Objective 1 confirm the impact of transmission constraints on the state's decarbonization pathways. Under the No Transmission Constraint scenarios, curtailments are reduced, and energy can be delivered more efficiently around the region, thereby reducing the overall clean energy capacity needed to meet the Regional Emissions Target. As noted in Objective 5, the current ISO-NE transmission planning process has hindered the development of transmission resources in concert with clean energy procurements. While Connecticut, and other states like Massachusetts and Rhode Island, have been actively procuring zero carbon resources with in-service dates two to five years after selection, transmission projects continue to take nearly a decade to complete. Moreover, the amount of clean energy and OSW in particular that the states have procured to date is nearing the cap for interconnection at the limited number of PTFs along the New England coastline. Given that the modeling in Objective 1 projects a regional need of over 10 GW of OSW under the Base Load Balanced Blend, and 15 GW under the Electrification Load Balanced Blend, investment in transmission upgrades is necessary to successfully integrate these zero carbon resources.

The availability of transmission to deliver large-scale hydropower from Canada down to New England also has significant implications. The modeling recognized that despite the substantial availability of low-cost hydroelectric capacity in Canada, importing it is limited by transmission through northern New England. As revealed by the NECEC development process, siting transmission lines is a real challenge in New England. Therefore, the model limited additional hydro imports from Canada to 1200 MW past the scheduled addition of NECEC. Should additional hydroelectric imports materialize in the future, it is important to note that this could serve as a scalable alternative to nuclear resources and could potentially reduce the quantities of additional renewable resources and reserves needed to meet the Regional Emissions Target. Connecticut must continue to monitor the development of hydro imports from Canada as it plans for a 100% zero carbon electric supply.

Aligning Procurements with Other States

The Department has found that aligning solicitations for resources with neighboring states, particularly large-scale resources like offshore wind, or resources requiring a large transmission investment, is useful to potentially capture economies of scale in purchasing, and at a minimum receive additional project variations for pricing and size, contingent upon action in the neighboring state.[286]

With respect to RFPs for power purchase agreements for offshore wind, Massachusetts DOER recently acknowledged the potential benefits in aligning solicitations and noted it would work with neighboring states to evaluate the costs and benefits of coordinating procurement timelines.[287] Massachusetts DOER recommended conducting the next solicitation in 2022 and allowing for bundled generation and transmission for up to 1,600 MW. Coordination with Massachusetts and other states in the region including New York could reduce costs and avoid bottlenecking delays. Therefore, DEEP will stay engaged with regional states and endeavor to align procurement timing to leverage these benefits for Connecticut ratepayers. These procurements, which may include OSW eligibility, may occur earlier than the timeline discussed above.

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[286] DEEP conducted a procurement in coordination with Massachusetts and Rhode Island, called the Three State RFP, in 2016/17 for renewables like solar and large-scale hydropower. In addition, DEEP aligned the timing of two of its procurements for offshore wind in 2018 and 2019 with Massachusetts.

[287] Commonwealth of Massachusetts, Department of Energy Resources, "Offshore Wind Energy Transmission under Section 21 of Chapter 227 of the Acts of 2018," (Jul. 28, 2020), *available at* https://www.mass.gov/doc/offshore-wind-transmission-letter-07-28-20/download

As discussed in Strategy 2 and 3, Connecticut is working with other New England states on a regional solution to ISO-New England market design flaws (and governance changes) that fail to account for the state's energy policy priorities. Remedying these flaws is essential to ensure that Connecticut ratepayers receive maximum value from the clean energy resources the state procures. The best decarbonization strategy for Connecticut's ratepayers would be the design and implementation of a new unified, regional market design that will achieve the State's zero carbon energy goals. A successful regional market design would replace the State's procurement mechanism as the means to secure needed clean energy resources and enable the states to achieve their clean energy mandates through the market itself.

Taking all of the above contingencies into account, this IRP concludes that with significant quantities of clean energy under contract, no new procurements of zero carbon Class I resources are needed in 2021 or 2022 to ensure continued progress towards the state's emission goals. Moreover, there is a critical need and opportunity to (1) pursue reforms to the wholesale market to provide for a unified, regional mechanism to meet our public policy needs, including retaining existing zero-carbon resources like Millstone and building new clean energy resources, and (2) engage in transmission planning for transmission or non-wires alternatives that are needed to enable the interconnection of additional quantities of offshore wind, and to reduce spillage of variable renewable resources. These reforms are essential to achieving an effective and affordable path to decarbonizing the electric sector and will be a focus for 2021 and 2022. The success of these efforts will impact the timing of when new clean energy will need to be procured, as discussed above.

During this time, DEEP will also monitor already contracted resources to ensure that they reach planned in-service dates, and will monitor technology cost trends, incentive availability, and procurement activity among neighboring states to also inform whether to initiate procurements earlier. If market reforms are unsuccessful, DEEP will reevaluate procurement strategies for grid-scale zero carbon Class I resources, to account for the potential retirement of Millstone at the end of the existing contract period, and ensure the electric sector contributes sufficient reductions to meet the economy-wide 2030 goal.

Before issuing any new grid-scale procurement, in 2021 DEEP will also initiate a preparatory proceeding to gather public input and provide renewable and clean energy developers and the public the opportunity to provide feedback DEEP's procurement mechanisms. Potential areas for feedback include: enhancements to the procurement design to improve competition; alignment with transmission planning and procurement; issues related to equity and diversity; types of information required to be submitted in bids; confidentiality afforded to bidders in DEEP's procurement process and the subsequent PURA proceeding; coordination with other states in the region; aligning procurements with Connecticut's siting and permitting requirements; and other issues.

Offshore Wind Procurement Schedule

Connecticut has already made significant progress towards its 100% Zero Carbon Target, in part due to its procurements of OSW resources to date, equivalent to 19 percent of the state's EDC load. Public Act 19-71[288] requires DEEP to provide a procurement schedule for OSW informed by the IRP, providing for the solicitation of resources with an aggregate nameplate capacity of 2000 MW by 2030.

[288] Section 1, Public Act 19-71, An Act Concerning the Procurement of Energy Derived from Offshore Wind, codified at Conn. Gen. Stat. § 16a-3n(a)(1).

The modeling results do not show a need for OSW until 2032 (under the Electrification Load Balanced Blend) or 2034 (under the Base Load Balanced Blend) without Millstone operating. According to the model, the amounts needed to achieve the 100% Zero Carbon Target in 2040 total 3,745 MWs and 5,710 MWs of additional OSW, respectively. Offshore wind resources are expected to need approximately 5-6 years from procurement award to reach commercial operation, thus, if not procured sooner, this additional OSW would need to be procured between 2026 and 2028. That projection is sensitive to a variety of contingencies, including the electric sector's progress in contributing to its share of the 2030 economy-wide goal, the amount of increased load due to electrification of the transportation and building sectors, and whether other procured resources reach commercial operation.

However, the IRP modeling demonstrates that additional zero carbon resources are needed beginning in 2026. While the model selected solar resources to fill that need, the takeaway is the amount of the resource needed, not a particular technology. DEEP does not generally conduct procurements for one specific resource. The projected need for additional zero carbon resources begins in 2026. If that does not change based on the contingencies noted above, in order to allow lead time for development, DEEP will conduct a procurement for zero carbon resources in 2023, open to Class I zero carbon resources, including OSW.

In order to comply with Public Act 19-71, based on the modeling in Objective 1 and the discussion above, the following is a more specific schedule of procurement activity for the state, including offshore wind, subject to contingencies:

- 2021 & 2022: Focus on transmission planning and procurement, and market reforms needed to enable procurement of additional offshore wind resources and other zero carbon Class I resources.
- 2023: Conduct a procurement for zero carbon Class I resources, including OSW.
- Prior to 2028, depending on contingencies: Procure additional zero carbon Class I resources, including OSW.

With this estimated procurement schedule, it is expected that the existing 2000 MW authority pursuant to Public Act 19-71, 1200 MW of which remains, will be fully utilized.

In order to achieve the 100% Zero Carbon Target by 2040 at the least cost, it will be important to retain flexibility in planning and executing procurements so as not to procure more resources than are needed. Prices are expected to decline over time as technology advances and the workforce becomes more established. Most importantly, in the near term, it is important to solve for transmission constraints that will be key to unlocking additional OSW potential, as discussed in more detail in Objective 5. The Department will monitor contingencies and update its procurement schedule for OSW and other zero carbon Class I resources no less than every 12 months to account for any changing market and policy conditions through the release of the next IRP, and will release its next updated procurement schedule by January 1, 2022. In subsequent IRPs and proceedings, DEEP will continually refine this procurement schedule.

6. Structure the successor tariff programs supporting distributed generation to achieve historic deployment levels and equitably distribute the benefits of zero carbon generation

Objectives: 1, 2, 3, 4

Public Act 18-50 expanded the DG programs in Connecticut to ensure the success of the state's growing renewable energy industry and promote sustainable Solar PV energy growth in the region. In addition, it utilized the successes of competition in existing programs to drive down prices paid for by all ratepayers and combined separate programs purchasing energy and RECs into a single program to ease participation. Public Act 18-50, as amended by Public Act 19-35, represents a significant financial commitment to distributed generation growth in Connecticut. It authorizes: (1) unlimited residential solar; (2) 50 MW/year for six years (300 MW total) for zero emission resources as a ZREC and VNM successor; 10 MW/year for six years (60 MW total) for low emission resources as an LREC and VNM successor; and (3) 25 MW/year for six years (150 MW total) for shared clean energy facilities.

The successor tariffs will create a transparent incentive program for both energy and RECs associated with DG that provides a fixed incentive to participants. This incentive can then be adjusted for declining federal incentives on behalf of the participant and capture declining technology costs on behalf of all ratepayers.

It is important to maintain historic deployment levels of DG achieved through the RSIP and LREC/ZREC programs to continue the pace of diversifying the State's zero carbon resources and sustain the existing in-state economic infrastructure supporting these programs.[289, 290,291]

Table S1: MWs of Solar Accepted Each Year by Program, 2012-2019

Year	LREC	ZREC	RSIP
2012		16.8	5.5
2013		25.3	10.4
2014	7.0	39.8	33.3
2015	9.8	32.1	54.1
2016	2.9	41.0	44.9
2017	3.6	68.3	35.6
2018	18.8	80.1	53.8
2019	33.5	56.5	65.5

[289] DEEP has not included the virtual net metering program in this table because most, if not all, of the virtual net metering projects also participate in either LREC or ZREC. Thus, virtual net metering projects are reflected in the deployment levels of LREC and ZREC. DEEP recognizes the importance of continuing the structure of the virtual net metering program in the successor tariffs to support municipalities, the state, and agricultural customers.

[290] DEEP 2018 Integrated Resources Plan. Data Request to the Electric Distribution Companies. July 10, 2020. Retrieved from HYPERLINK "http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=8.5&Seq=5" http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=8.5&Seq=5

[291] Connecticut Green Bank. "Excel Spreadsheet for Residential Solar Installations in Connecticut for Information on system costs, sizes, contractors installing systems and other details" June 2, 2020. Retrieved from http://www.gosolarct.com/1-Get-Into-Solar/Connecticut-Solar-Market-Data

Table S2: MWs of Fuel Cells Accepted Each Year by Program, 2012-2019

Year	LREC
2012	5.0
2013	4.9
2014	6.0
2015	2.1
2016	8.6
2017	5.0
2018	2.7
2019	10.6

Based on the data in Tables S1 and S2 above, the RSIP program accepted an average of 48 MWs of solar each year between 2014 and 2019, when the program was more mature, with 65 MWs deployed in 2019. The LREC/ZREC program accepted an average of 13 MWs and 53 MWs, respectively, of solar each year during the same time. The LREC program brought an average of 6 MWs of fuel cells online. While the RSIP numbers are reflective of actual installations, the LREC/ZREC program typically has an attrition rate of 45 percent and installed MWs resulting from each procurement year are less than what is presented in the table.[292]

While distributed generation provides many benefits, the ratepayer cost of deploying an additional 52 MWs of DG solar per year, on average, in the Base Load BTM Emphasis scenario is $848 million above the cost of the Base Load Balanced Blend scenario, and $4.6 billion above the cost of the Reference scenario. These costs are conservative estimates because they are based on the cost of installing the distributed solar from NREL, not based on the cost of the current compensation structure under net metering paired with a REC purchase program. In developing a recommendation for targeting distributed generation installations in furtherance of the 100% Zero Carbon Target, DEEP must balance both these significant costs to all ratepayers with the benefits these installations provide to participants and the broader electric grid.

Therefore, in order to maintain at least historic distributed generation deployment levels, this IRP recommends PURA aim to deploy up to 65 MWs per year of residential rooftop solar in developing the compensation structure for the successor program in Docket No. 20-07-01 pursuant to Section 16-244z(b), consistent with peak deployment in 2019. The Department supports maintaining 2019 deployment levels to sustain the rooftop solar industry while PURA works to maximize the benefits of DG deployed on the system. The Department also recommends PURA structure the incentive levels to ensure at least 40 percent of the installations are deployed at low income households statewide, and low to moderate income households in environmental justice communities, to improve energy affordability for historically underserved and overburdened customers. To achieve this goal, the feasibility of providing an additional incentive to reduce or eliminate up-front costs should be explored, thus reducing barriers to entry for underserved customers.

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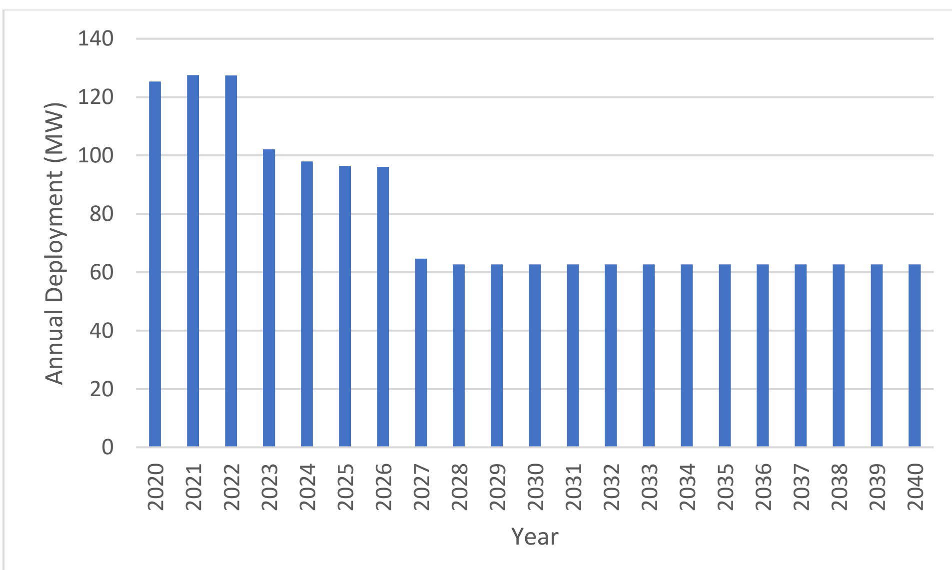
[292] Connecticut DEEP. Letter to Jon Black, Helve Saarela, and Joseph Roberts of ISO-New England. February 24, 2020. *Available at:* https://www.iso-ne.com/static-assets/documents/2020/03/ctdeep_2020draft_pv_forecast_comments.pdf

The Department will continue to assess the progress made in grid modernization proceedings and other proceedings impacting distributed generation and advocate for structures that maximize the grid benefits of solar while also leveraging the benefits to participants, particularly solar paired with storage. The Department may recommend increased distributed generation deployment levels under certain conditions, including as policies are implemented to capture the grid benefits of solar paired with storage, if deployment levels above 40 percent for low-to-moderate income homes can be successfully achieved, or if PURA is able to set a rate that is more competitive with grid scale projects.

Finally, this IRP supports the existing statutory maximums for the LREC/ZREC successor program of 50 MW of solar and 10 MW of fuel cells per year, and 25 MW of SCEF. The Department recommends that PURA explore methods to ensure winning projects achieve commercial operation in the final LREC/ZREC procurement and successor procurement program for similar resources to reduce the current attrition rate. These distributed generation deployment levels – 65 MW of residential rooftop solar, 50 MW of commercial solar, 10 MW of commercial fuel cells, and 25 MW of SCEF – are more than the deployment levels assumed in all scenarios other than the BTM Emphasis scenario, which results in an average BTM solar deployment of 97 MWs per year from 2022-2027, inclusive of both residential and commercial BTM solar. See Figure S1 below. To further address energy equity and affordability, the low-income and low- to moderate-income subscribership requirements under the SCEF program structure should be increased, working towards a 100 percent low- to moderate-income subscribership goal. The Department appreciates the novel design of the SCEF program and the fact that the EDCs are in the process of developing a system to obtain and maintain the program subscribership levels. As the program evolves, it is important to work towards this 100 percent low- to moderate-income subscribership goal to support energy equity and relieve energy burden for vulnerable populations, while also helping reduce arrearages that become uncollectible, the cost of which is borne by all ratepayers.

Figure S1: Modeling BTM Solar Incremental Additions by Year, 2020-2040[293]



[293] These BTM assumptions were used in the Balanced Blend, Millstone Extension, and No Transmission Constraint policy cases. The BTM Emphasis case deployed approximately 72% more BTM on average.

7. Investigate whether it is in the best interest of ratepayers to retain RECs procured by the EDCs on behalf of all ratepayers to meet our State climate goals

Objectives: 1, 7

The Department recommends PURA initiate a proceeding to investigate whether the EDCs should retain the RECs procured by all ratepayers in energy policy programs like DEEP's grid-scale competitive procurements and DG REC purchase programs and retire them on behalf of all electric ratepayers, including those utilizing competitive suppliers. The Department recognizes that PURA's investigation may result in a finding that a statutory change is necessary to achieve the optimal solution.

In addition, DEEP is in the process of making refinements to the State's inventory reporting to align with the accounting method used in this IRP and take credit for renewable and zero carbon resources from an emissions perspective based on RECs and environmental attributes settled in Connecticut.

8. Address the impact behind-the-meter resources have on reducing overall RPS compliance obligations

Objectives: 1, 2

As discussed in Objective 2, the State's clean energy policies effectively count BTM resources twice: once as a load reducer and once as a generator through the production of RECs. This "double count" has the unintended consequence of reducing Connecticut's annual RPS percentage because as BTM resources reduce the total load for the state, it coincidentally reduces how many RECs must be purchased by load serving entities. There are two basic approaches to reversing the effective reduction in Connecticut's Class I RPS requirement due to "double counting":

- Reduce, limit, or phase-out the eligibility of BTM resources for Class I RECs via legislation, or administrative action if possible.
- Change the way the State's Class I RPS requirement is calculated by adding BTM generation to the settled load used to determine the RPS requirement.

Both approaches have obstacles to implementation. The first approach would impact the compensation structure for the successor tariffs authorized under Section 16-244z(b) of the General Statutes because all value would be derived from the energy rather than the RECs for the average cost of installing the generation project and a reasonable rate of return. In addition, the first approach would impact the bidding structure in the procurements authorized by Section 16-244z(a) of the General Statutes because the bid prices would be tied only to the energy delivered rather than the energy and RECs delivered. This approach would heavily impact the current BTM programs, as the RSIP and LREC/ZREC program both provide compensation for only RECs. If this approach were utilized, existing BTM programs like RSIP and LREC/ZREC would need to be grandfathered to allow these RECs to continue to be sold for RPS compliance purposes.

An alternative option under this approach would be for the EDCs to not claim BTM RECs purchased pursuant to RSIP and LREC/ZREC for compliance with the RPS, but to also not sell them into the regional market (effectively 'canceling' them). It is unclear if PURA has the authority to direct the EDCs to take this action, or if legislative action would be required.

The second approach may not be administratively possible. If it is possible, it may create significant uncertainty for suppliers and the EDCs. An alternative option would be for the State to increase its RPS requirement to account for the load reduced by BTM resources, although this option would be imprecise as an estimate of future BTM deployment would be necessary.

This issue should be investigated by PURA to consider these options, and other potential alternatives, to eliminate the impact BTM resources have on reducing overall RPS compliance obligations. No change is recommended at this time to existing programs like RSIP and LREC/ZREC because it would be disruptive to the financing of those existing projects. However, the creation of the new residential solar tariff program under Section 16-244z(b) of the General Statutes (i.e. the RSIP + net metering successor program) in PURA Docket No. 20-07-01 and the structure of the competitive procurements authorized by Section 16-244z(a) of the General Statutes (i.e. the LREC/ZREC + net metering/virtual net metering successor program) starting in 2022 makes this issue ripe for consideration.

9. Engage in coordinated planning for workforce and economic development

Objectives: 2, 3, 5

The findings in Objective 1 highlight both Connecticut's continued reliance on energy efficiency to minimize overall load, and its growing reliance on zero carbon generation technologies in order to meet its 100% Zero Carbon Target. These needs demonstrate that a robust, skilled workforce is critical to the state achieving its goals. This IRP discusses these needs in both Objective 5, and in Strategy 5 above. The transition to a clean energy economy provides significant economic opportunity to our residents, businesses, and communities. Investment in energy efficiency and solar over the last two decades has significantly grown employment in the state's clean energy sector.

With respect to offshore wind, through collective investments in this emerging resource, the Northeastern states have jump started the OSW industry in the U.S., and demonstrated commitments to allow the industry to firm up the supply chain and workforce.[294] The significant amount of offshore wind procurement activity in the Northeast will likely result in economic activity for many regional ports as well as regional supply chain and work force development opportunities. Connecticut's available ports and manufacturers have features that make them attractive prospects for economic development related to offshore wind regardless of whether procurements occur in Connecticut or in neighboring states, thereby bringing the benefits of the clean energy economy to Connecticut's environmental justice communities in which key ports and manufacturers are located. Under the leadership of Governor Lamont, DEEP is currently collaborating with the Department of Economic and Community Development and other entities to develop a plan to ensure that Connecticut ports, manufacturers, and workers are well positioned to leverage the significant opportunities to be provided by this high growth clean energy industry.

[294] Massachusetts has 1,604 MW of offshore wind under contract, with plans to conduct additional procurements. Rhode Island has 430 MW of offshore wind under contract, with plans to procurement up to 600 MW more. New York has 1,826 MW of offshore wind under contract, with plans to procure more.

The Department will coordinate with DECD and its Office of Workforce Strategy, as well as other state agencies and stakeholders, to develop a strategic and equitable approach to clean energy economic and workforce development in Connecticut.

10. Conduct a stakeholder process to improve the transparency, predictability, and efficiency of solar siting and permitting in Connecticut

Objectives: 1, 3, 4

Under the various modeling scenarios in Objective 1, solar resources play a significant part in meeting a 100% Zero Carbon Target by 2040. Not all of the thousands of megawatts needed to meet this target will be developed in Connecticut, but many will. It is critical to ensure that the process for siting and permitting ground-mounted systems is as transparent, efficient, and predictable as possible, and that renewable procurements—whether contract- or tariff-based—incorporate eligibility criteria that reflect a consistent and appropriate balance of price and environmental quality and natural resource values.

This IRP calls for a stakeholder engagement process, led by DEEP, to improve and refine solar siting and permitting practices with respect to grid-scale procurements, and to develop siting practices tailored to BTM, VNM, and LREC/ZREC solar projects. The Department's Environmental Conservation, Environmental Quality, and Energy branches will seek to engage with developers, PURA, the Department of Agriculture, the EDCs, environmental justice advocates, environmental advocates, interested legislators, and other stakeholders to explore preferential siting practices through the use of eligibility criteria, selection weighting factors, and favorable compensation rate incentives.

Examples of preferential siting practices include measures that prioritize the selection of projects in developed, abandoned or underutilized areas over undeveloped greenfields; preserve agricultural farmland; avoid steep slopes, minimize soil erosion and sedimentation; avoid disturbances of valued natural resources such as core forests, wetlands, and endangered, threatened or species of Special Concern and their habitats;[295] preserve sites with archaeological, historic or culturally significant resources; and avoid visual and aesthetic impacts to residential and recreational facilities.

The incorporation of best siting and permitting practices in procurement criteria will ensure fair pricing and competition, reduce project risk and speed deployment. Any new approaches must be developed in a transparent manner and phased in prospectively, so developers can plan for them as they are searching for sites.

11. Leverage Regional Coordination to Develop Best Practices for Offshore Wind Siting

Objective: 4

States across the region are procuring offshore wind in the same or adjacent federal lease areas as projects procured by Connecticut and navigating similar challenges with regard to siting and

[295] Endangered and Threatened Species, and Species of Special Concern, Title 26 R.C.S.A. §§ 26-306-1 through 26-306-7. *Available at* https://eregulations.ct.gov/eRegsPortal/Browse/getDocument?guid=%7B70A4E155-0500-CAF4-90F5-B8F279ABC1B5%7D

environmental and fisheries mitigation. The Department will continue coordinating with regional entities that are investigating these issues, such as the Northeast Regional Ocean Council, the Responsible Offshore Development Alliance/Responsible Offshore Science Alliance, and, once established, the Regional Wildlife Science Entity for Offshore Wind, to improve our understanding of the best available science, tools, and practices for environmental and commercial fisheries mitigation and allow us to continually improve our solicitations as they pertain to planning and siting. The Department will leverage these regional approaches to developing best practices in offshore wind siting and incorporate siting requirements in future solicitations. As required by Public Act 19-71, DEEP will also utilize input from the Commission on Environmental Standards for each future solicitation pursuant to that Public Act.

12. Invest in the deployment of cost-effective energy efficiency and active demand response

Objectives: 1, 2, 3

In 2016, DEEP conducted a procurement that allowed energy efficiency to compete as an eligible resource as authorized by Public Act 15-107. In addition to over 350 MW of wind and solar, DEEP selected 34 MW of energy efficiency as part of this authority. The 34 MW of energy efficiency selected had an original completion of deployment of 2021, but installation was accelerated because of legislative sweeps to the C&LM Plan budget and savings have been delivered substantially ahead of schedule as reported in the First Annual Measurement and Verification Report.[296] The ability to quickly deploy efficiency as compared to other energy resources represents a significant benefit, enabling energy efficiency to fill in gaps where needed to meet the 100% Zero Carbon Target. In addition, energy efficiency and demand response deliver bill savings to participating customers. Innovative electric demand response strategies can help customers and grid operators manage shifting loads, particularly as we move toward building and vehicle sector electrification. Demand reduction assets could be managed through the use of innovative control structures to be fully integrated in a modernized grid. In order to leverage these benefits, this IRP recommends authority for DEEP to procure energy efficiency and demand response that complements the existing C&LM programs. Conducting additional procurements for energy efficiency and active demand response would expedite the reduction of GHG emissions, decrease the need for new zero carbon generating resources, and help reduce customers' energy burden.

This IRP also recommends that the C&LM programs further develop natural gas demand response programs, to free up gas demand to be used for electricity generation and improve electric resilience during winter peaks that occur due to extreme cold weather.

[296] Eversource Energy. PURA Docket No. 17-0-11. *First Annual Measurement and Verification Report*. March 14, 2019. *Available at* http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/32fde53ee1a2d406852583bd00659351/$FILE/2017-2018%20Incremental%20EE%20Bid%20Annual%20MV%20Report_Final.pdf

13. Support the development of energy storage resources that can support the reliable integration of variable renewables.

Objectives: 1, 2, 3

Energy storage and active demand response will play a critical role in an increasingly decarbonized electric sector by helping to shape the load of variable zero carbon resources like wind and solar to better match demand. The modeling results in Objective 1 estimate the need for 1,060 MWs of new energy storage capacity starting in 2031 by 2040 in the Base Load Balanced Blend scenario and 1,603 MWs in the Electrification Load Balanced Blend scenario starting in 2030 to help meet the 100% Zero Carbon Target—highlighting the importance of pairing resources like storage with intermittent renewable energy sources, especially if baseload zero carbon resources like nuclear retire.

Battery storage capital costs are predicted to exponentially decline over the next two decades, as discussed in Appendix A1. Battery storage provides multiple services, depending on how it is operated and configured. With respect to the state's energy supply, battery storage located behind the customer meter can provide for increased on-site consumption of distributed solar. PURA's grid modernization dockets are evaluating many of the opportunities for energy storage, including storage that provides customer and distribution system benefits.

DEEP has to date solicited bids for grid-located storage resources paired with renewables as part of several recent grid-scale resource competitive procurements. Insights from these procurements point to the need to consider valuing firmness and deliverability of energy, in addition to emissions reductions and RPS compliance, as part of bid evaluation, to more effectively evaluate the attributes that energy storage projects can bring to a resource.

The modeling in Objective 1 projects a need to begin procuring storage resources in 2027-28 in the Balanced Blend scenarios under both load cases. Procurement authority for storage will be needed, and procurement structures will need to be refined, advance of when these resources would be needed. This schedule allows DEEP to minimize costs and strategically plan in coordination with other future procurements. The modeling in this IRP focused primarily on battery storage (and some pumped hydro). While DEEP will continue to track the development of this technology, it will also monitor trends in alternative and nascent storage technologies, such as the production of renewable hydrogen, and consider their potential in future iterations of the IRP.

14. Phase down the value of biomass RECs eligible as a Class I renewable energy source to diversify the resources supported by Connecticut's Renewable Portfolio Standard

Objectives: 1, 6

The Department supports the recommendation from the 2018 CES to phase down the value of biomass RECs in Connecticut's Class I RPS. Pursuant to Public Act 13-303, to implement this phasedown, eligible generation for Class I biomass RECs will be reduced after 20 years for new facilities and 15 years for existing facilities from the time they were approved as a Class I renewable energy source in Connecticut. The Department believes it is appropriate to apply the new/existing facility designations that PURA established for hydropower to biomass.[297] This phasedown schedule will provide both new and existing facilities reasonable time to amortize their investments.

After the initial 15- or 20-year license period ends, the amount of generation eligible as a Class I resource will be reduced for each biomass project, which will gradually reduce the value of Class I RECs to all biomass facilities. Class I RECs will still be generated as they have been, but the amount of generation eligible as a Class I resource in Connecticut will decline to 50 percent of the actual generation output from the facility each year. One MWh would still be required to be produced to receive a REC in Connecticut. A REC for a Class I biomass facility would not be treated any differently from CT Class I RECs from other eligible resources for the purpose of supplier compliance. The other 50 percent of the annual generation output, which is not eligible in Connecticut, will still be eligible to be sold to meet RPS requirements in other states, to the extent the resource is eligible to participate in those other state RPS programs. Implementing this phasedown schedule will help to diversify resources supported by the state, focus incentives on resources that support in-state forestry and waste management goals, and help fulfill the goals of the GWSA. Freeing up Class I RECs historically met by biomass allows more of the State's funding to be targeted towards eligible zero carbon resources, and better aligning with its 100% Zero Carbon Target. This phase down will begin to take effect in 2022.[298]

To effectuate this change, DEEP will submit a request through the NEPOOL GIS Working Group and the Markets Committee. The Department does not expect for it to take significant time to make the necessary changes.

15. Diversify the state's materials management infrastructure through investment in more sustainable materials management strategies and facilities

Objectives: 1, 2, 4, 6

The Department has committed to continuously focusing on the intersections between renewable energy, climate, and materials management goals.[138] This includes evaluating how incentives can be used to promote renewable energy from waste, and exploring opportunities for pre-development financing for anaerobic digestion and other waste conversion technologies.[139]

The state has for many years provided ratepayer support to WTE facilities through the RPS Class II tier, as those facilities have provided for an essential in-state disposal option that is preferred under the

[297] New facilities are those that began operation after 2003 and existing facilities are those that began operation prior to 2003. An existing facility may be considered a new facility if it was abandoned for at least two consecutive years and there had been a capital investment in the structure greater than 50% of the total value of the equipment at the facility. Many existing facilities made significant investments for emission control equipment to qualify as a Class I renewable energy source. (PURA Final Decision, DPUC Declaratory Ruling Concerning "Run-of-the-River Hydropower" as that Term is Used in the Definitions of Class I and Class II Renewable Energy Source in C.G.S. § 16-1(a)(26) & (27), Docket No. 04-02- 07, 13-14 (Sep. 10, 2004).
[298] Pursuant to Section 5 of Public Act 13-303, "shall not apply to any biomass or landfill methane gas facility that has entered into a power purchase agreement (1) with an electric supplier or electric distribution company in the state of Connecticut on or before the effective date of this section, or (2) executed in accordance with section 6 or 8 of this act." Thus, this phasedown will not apply to the Plainfield Renewable Energy facility because it has an existing contract.

state's waste hierarchy to landfilling. In recent years, ratepayers have contributed approximately $12 million to $17 million to WTE facilities annually through the RPS. WTE facilities emit greenhouse gases and other air pollutants, but have played a key role in providing reliable disposal for large volumes of solid waste over the years.

Ensuring reliable, affordable materials management options is a prime concern for the state. Present circumstances—including the aging condition of one of the state's largest WTE facilities—make it essential that the state seek opportunities to scale sustainable waste management alternatives that can provide alternatives to WTE and out-of-state landfilling for solid waste disposal. Over time, this can reduce the state's reliance on these disposal options and improve environmental quality, especially for environmental justice communities.

The Comprehensive Materials Management Strategy (CMMS) projects that approximately 300,000 tons (15 percent) of Connecticut's MSW could be diverted from disposal at waste to energy (WTE) facilities, and instead be processed using technologies such as anaerobic digestion.[140] In order to successfully deploy anaerobic digestion statewide, it is critical to develop an efficient network for organics collection to divert organic materials from the solid waste stream and put it to beneficial use at anaerobic digestion facilities. A process to build a collaborative network began in September 2020, when DEEP joined with more than 70 municipalities statewide, committing to work together as the Connecticut Coalition for Sustainable Materials Management (CCSMM) to collectively develop a set of waste reduction strategies by the end of 2020, including organics diversion strategies. To support these efforts, changes may be needed to the State's organics recycling laws to require more commercial businesses and other generators to send food scraps and organic material for recycling at composting and anaerobic digestion facilities.

Finally, DEEP has authority to procure energy and Class I RECs associated with anaerobic digesters, and is seeking additional legislative authority to procure biogas from anaerobic digestion to supply the gas distribution system.[299] As it is fundamental to the ability to commoditize biogas, DEEP supports the efforts at PURA to define and adopt gas quality interconnection standards for biogas suitable for injection into the gas distribution system. In Docket No. 19-07-04, PURA is considering proposed tariffs establishing interconnection standard for biogas facilities. Again, these efforts further decarbonize the gas distribution system and aid in the use of anaerobic digestion byproduct.

In any future procurements of anaerobic digesters, DEEP will require bidders to submit well-formed feedstock acquisition plans to demonstrate a well-developed understanding of the market opportunities and challenges, and will seek to align procurements with municipal engagement to target development strategically around the state to maximize proximate access to these facilities, and limit transportation costs for hauling organic feedstocks. The Department will continue to explore how to promote the development of this technology.

[299] Section 17, Public Act 19-35, An Act Concerning A Green Economy and Environmental Protection.

Part III: Analysis and Recommendations Concerning a Connecticut Portfolio Standard for Thermal Energy

Introduction

Connecticut's Integrated Resources Plan traditionally focuses exclusively on planning for the electricity sector, specifically electricity generation and transmission and an assessment of renewable electricity generation needed to meet the Renewable Portfolio Standard. In 2019, however, the Connecticut General Assembly directed that this IRP evaluate a policy relevant to the *thermal* sector – that is, energy used for space and water heating in residential and commercial buildings. Public Act 19-35 required DEEP to consider creation of a "portfolio standard for thermal energy," including "biodiesel that is blended into home heating oil."[300]

Burning fossil fuels for thermal uses in residences and businesses accounts for approximately one quarter of Connecticut's greenhouse gas (GHG) emissions.[301] Decarbonization of thermal energy must accelerate in the coming decades in order for Connecticut to meet its statutory economy-wide targets of 45 percent GHG emissions reduction by 2030 and 80 percent reduction by 2050.[302] Air- and ground-source heat pumps, especially when powered by low- and zero-carbon electricity sources, are capable of drastically reducing emissions in these sectors.[303] At present, however, heat pumps represent only a small fraction of the state's heating equipment.[304] Other mature or maturing renewable thermal

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[300] Public Act 19-35, An Act Concerning a Green Economy and Environmental Protection, 2019, section 10, *available at* https://www.cga.ct.gov/2019/ACT/pa/pdf/2019PA-00035-R00HB-05002-PA.pdf. The IRP addresses electric supply needs (C.G.S. §§ 16a-3a-3b). As such, DEEP interprets Section 10 of Public Act 19-35 as requiring DEEP to investigate the creation of a portfolio standard supported by electricity ratepayers.

[301] DEEP, 2017 Connecticut Greenhouse Gas Emissions Inventory, 2020, *available at* https://portal.ct.gov/-/media/DEEP/climatechange/2017_GHG_Inventory/2017_GHG_Inventory.pdf.

[302] *See* Public Act 08-98, An Act Concerning Connecticut Global Warming Solutions, *available at* https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm; and Public Act 18-82, An Act Concerning Climate change Planning and Resiliency, *available at* https://www.cga.ct.gov/2018/ACT/pa/pdf/2018PA-00082-R00SB-00007-PA.pdf.

[303] A significant and growing proportion of electricity consumed in Connecticut is generated from zero-carbon resources. Even if heat pumps were powered by electricity generated entirely with fossil fuels, these appliances would provide heat from renewable energy. This is because, unlike electric-resistance heating, heat pumps do not convert electricity into heat. Instead, they harness a relatively small amount of electricity to harvest a larger amount of heat energy from the atmosphere or ground – heat provided by sunlight. The "coefficient of performance" of heat pumps typically is 2-6 times greater than that of electric resistance heating due to this heat-harvesting function.

[304] Connecticut Governor's Council on Climate Change, "Building a Low Carbon Future for Connecticut: Achieving a 45% GHG reduction by 2030," pp. 36-38, *available at* https://portal.ct.gov/-/media/DEEP/climatechange/publications/BuildingaLowCarbonFutureforCTGC3Recommendationspdf.pdf.

technologies include solar water heating, solar space heating, biodiesel blended with heating oil, renewable natural gas, geothermal, and compost heat recovery.[305]

Key renewable thermal technologies widely deployable in Connecticut homes and businesses – heat pumps and solar water heating – face barriers to adoption: up-front capital costs and competition with fossil fuels whose prices do not account for large environmental externalities.[306] States have developed a variety of mechanisms to partially address these barriers, from providing incentives for the purchase of heat pump equipment through state energy-efficiency programs to building-code revisions and promotion of renewable natural gas.[307]

Fourteen states have adopted thermal renewable portfolio standard (T-RPS) programs.[308] To complement one-time purchase incentives, T-RPS programs provide ongoing financial support for production or use of low- and zero-carbon thermal energy – much as conventional RPS programs provide ongoing support for low- and zero-carbon electricity generation. The design of thermal RPS programs and the technologies or resources they support varies from state to state. In a basic design: the state designates certain categories of renewable thermal technologies as eligible to produce Renewable Energy Certificates (RECs); eligible BTUs are generated in households and businesses employing these technologies; RECs for these BTUs are aggregated by third parties (using a designated BTU/MWH equivalence factor) and tracked by the regional REC oversight body[309]; and revenues the aggregators earn by selling the RECs provide compensation for the participating households and businesses. Where they are supported in a T-RPS, heat pumps are compensated on the basis of metered or estimated BTU output, while biodiesel is compensated on the basis of the BTU content of each gallon of biodiesel delivered.[310]

In accordance with Public Act 19-35, DEEP has pursued an extensive fact-finding and stakeholder-engagement process. In November 2019, the agency issued a background document reviewing the

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[305] For a broad view of renewable thermal technologies, *see* International Energy Agency, Anselm Eisentraut and Adam Brown, "Heating Without Global Warming: Market Developments and Policy Considerations for Renewable Heat," 2014, https://www.iea.org/reports/heating-without-global-warming.

[306] Yale Center for Business and the Environment, "Feasibility of Renewable Thermal Technologies in Connecticut: A Field Study on Barriers and Drivers," 2017, https://cbey.yale.edu/research/feasibility-of-renewable-thermal-technologies-in-connecticut-barriers-and-drivers.

[307] *See e.g.*, 2021 Plan update to the 2019-2021 Conservation and Load Management Plan, *available at*, https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/FINAL-2021-Plan-Update-Filed-10302020.pdf (authorizing the state's electricity and natural gas distribution utilities to provide incentives for the purchase of electric air- and ground-source heat pumps).

[308] Clean Energy States Alliance, "Renewable Thermal in State Renewable Portfolio Standards," 2018, https://www.cesa.org/assets/2018-Files/Renewable-Thermal-RPS.pdf.

[309] In New England, this body is the New England Power Pool Generation Information System.

[310] For an overview of T-RPS program designs in Massachusetts, Vermont, Maine, and New Hampshire, see DEEP, "Renewable Thermal Portfolio Standard Programs in New England States," Nov. 19, 2019, http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/47469b57e3d1a355852584c40070531d/$FILE/Background.pdf.

structure and features of renewable thermal portfolio standard programs in New England states.[311] A public technical meeting the agency held on December 9, 2019, included presentations on relevant programs in Massachusetts, New Hampshire, Vermont, and 11 other states as well as panel discussions on best practices. This meeting also included presentations by, and active engagement with, representatives of the National Biodiesel Board, Connecticut Energy Marketers Association (CEMA), Massachusetts Energy Marketers Association, Kolmar Americas (a biodiesel manufacturer with a major production facility in Connecticut), two Connecticut fuel oil companies, and the Connecticut Geothermal Association.[312] The agency issued a request for written comments on December 19, 2019, regarding the framing of thermal renewable portfolio standards as well as issues relating to biodiesel in this context; and extensive comments were received.[313] A second public technical meeting scheduled for March 16, 2020 was postponed due to the COVID-19 pandemic and ultimately held July 13, 2020.[314] Two rounds of written comments were requested and received in conjunction with that meeting.

The National Biodiesel Board, CEMA, Kolmar, and a number of fuel oil dealers have urged adoption of a T-RPS. In their vision, a T-RPS recognizing biodiesel as an eligible thermal technology would enable fuel-oil distributors to invest in needed blending and storage infrastructure, boost the amount of biodiesel blended into the fuel delivered in Connecticut, and in the process allow these distributors to contribute to decarbonization of the thermal sector.[315]

This chapter: (a) considers the role that biodiesel blended into heating oil can play as a means to reduce GHG emissions from the thermal sector in accordance with the state's climate goals, and (b) considers a T-RPS as a potential mechanism. The analysis identifies existing barriers to the use of biodiesel blends

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[311] DEEP, "Renewable Thermal Portfolio Standard Programs in New England States," Nov. 19, 2019, available at http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/47469b57e3d1a355852584c40070531d/$FILE/Background.pdf.

[312] Technical meeting Presentations, Renewable Portfolio Standard as a Mechanism for Promoting Deployment of Renewable Thermal Technologies, DEEP, New Britain, CT, Dec. 9, 2019, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/473a61d275e0883e852584d2006b3bcd?OpenDocument.

[313] *See* DEEP, "Opportunity for Public Comment: Renewable Portfolio Standard for Thermal Resources" Nov. 19, 2019, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/47bf3b4f33bf2fbb852584d5004b5b20/$FILE/Request%20for%20comments%20-%20Revised%20FINAL.pdf.

[314]*See* DEEP, "Notice of Technical Meeting and Opportunity for Public Comment: Biodiesel as a Thermal Resource" June 24, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/a984e5cfadd86b3f85258591005b1363/$FILE/Notice%20of%20July%20technical%20meeting.pdf and "Biodiesel as a Thermal Resource," July 13, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/14b7939fcecae1b1852585c1006f5ca5/$FILE/Presentation.pdf.

[315] *See*, CEMA, "Supplemental Public Comment Biodiesel as a Thermal Resource," July 22, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/7fa9d821d3955af4852585af005eac3b?OpenDocument (CEMA argues for a T-RPS program in Connecticut, like the Alternative Portfolio Standard program in Massachusetts, that would channel revenues for biodiesel through fuel oil retailers rather than to customers, in contrast to revenues for renewable thermal energy production using other technologies that would be channeled directly to the household or business employing the technology).

above B20, unresolved questions regarding the air-quality impacts of biodiesel as a heating fuel, and concerns about the impacts on electric rates if a measure unrelated to the provision of electricity were included within the electric-ratepayer-supported RPS. Based on these considerations, this IRP does not recommend creation of a T-RPS that subsidizes biodiesel blended with heating oil at this time. Instead, this IRP recommends further, more holistic study of available mechanisms and technologies to support building decarbonization in the next iteration of the Comprehensive Energy Strategy.

Biodiesel as a thermal decarbonization strategy

Heating oil is the primary fuel used by about 40 percent of residences and perhaps 25 percent of commercial buildings in Connecticut and contributes 47 percent of thermal GHG emissions in these sectors.[316] Combusting a gallon of heating oil (unblended with biodiesel) produces 22.5 pounds of carbon dioxide.

Biodiesel is a liquid biofuel that in most respects is functionally equivalent to conventional fuel oil.[317] Some biodiesel, including most that is manufactured in Connecticut, is produced from waste biological feedstocks, including used cooking oil and waste food grease. Nationally, however, most biodiesel is produced with virgin feedstocks, principally soy oil. Biodiesel is routinely blended with heating oil (and diesel fuel for vehicles) and in 2016 constituted about 7 percent of fuel oil distributed in Connecticut.[318] One of the clear advantages of biodiesel as a renewable thermal technology in Connecticut is that significantly higher proportions – up to at least B20– and potentially beyond – can be burned in oil-fired boilers without necessitating alterations in that equipment.[319] Given lower lifecycle GHG emissions attributed to biodiesel (discussed below), the state's fuel-oil dealers, who have seen a 37 percent decline in residential sales since 2004[320], contend this offers a path for them to transition to delivery of clean fuels.[321] The Department requested but received no definitive information on the magnitude and

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[316] *See* DEEP, Comprehensive Energy Strategy: Building Sector, 2018, p. 68, *available at* https://portal.ct.gov/-/media/DEEP/energy/CES/BuildingsSectorpdf.pdf; U.S. Energy Information Administration, Commercial Buildings Energy Consumption Survey, Table B5, *available at* https://www.eia.gov/consumption/commercial/data/2012/bc/pdf/b5.pdf; DEEP, "2017 GHG Inventory Final Public – supporting data," *available at* https://portal.ct.gov/DEEP/Climate-Change/CT-Greenhouse-Gas-Inventory-Reports.

[317] *See* Alternative Fuels Data Center, "Biodiesel," *available at* https://afdc.energy.gov/fuels/biodiesel.html.

[318] UCONN study commissioned by CEMA, "Data on Biodiesel Concentration in CT fuel oil samples, 1/18/2016-8/26/2016," September 2016.

[319] B20 is a blend of 20 percent biodiesel and 80 percent petroleum fuel oil. B50 is 50 percent biodiesel.

[320] *See* U.S. Energy Information Administration, "Connecticut total distillate adjusted sales/deliveries to residential consumers," available at https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=KD0VARSCT1&f=A.

[321] *See*, CEMA, "Supplemental Public Comment Biodiesel as a Thermal Resource," July 22, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/7fa9d821d3955af4852585af005eac3b?OpenDocument; CEMA, "Biodiesel as a Thermal Resource," July 8, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/024233f02356cf04852585a0005db990?OpenDocument; and Sack Energy, "Comments on Biodiesel as a Thermal Resource," July 8, 2020, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/fc2892ba91d65bb1852585a40008d307/$FILE/Ct%20TREC%207-13-2020.pdf.

cost of distribution-infrastructure upgrades that would be needed for Connecticut's fuel-oil wholesalers to provide statewide distribution of B20 and B50 blends.

In this section several aspects of the merits of expanding use of biodiesel blends in Connecticut are considered:

- nitrogen oxide emissions from biodiesel combustion;
- how feedstock and production location may affect GHG emissions reductions attributable to biodiesel; and
- the potential for biodiesel incentives to perpetuate use of fossil fuels.

NOx emissions – Connecticut is a non-attainment area for ozone under federal air-quality standards, and NOx (oxides of nitrogen) is a potent precursor for ozone formation, obligating the state to aggressively pursue policies to further reduce NOx emissions within the state. Both NOx and ozone damage the human respiratory system. A gallon of fuel oil combusted in a residential boiler produces about 0.018 pounds of NOx. An emissions study cited by the National Biodiesel Board points to lower NOx concentrations in emissions from boilers burning biodiesel relative to boilers burning conventional fuel oil.[322] The available literature is inconsistent on this point, however: some studies find lower concentrations, some higher concentrations, and some equivalent concentrations.[323] More important, there is evidence that even if NOx *concentrations* in the exhaust of boilers burning biodiesel are somewhat lower or equivalent to boilers burning unblended heating oil, the *mass of NOx emissions* delivered to the atmosphere may be higher per mmBTU of fuel burned.[324] Available data on NOx emissions associated with burning biodiesel in boilers is quite limited, and the quality of data is generally poor. At present the only study addressing mass of emissions rather than merely concentration of emissions – and hence the best available evidence on the matter – appears to be a 2008 U.S. EPA report that found burning biodiesel made from soy oil resulted in a 12 percent increase in the mass of NOx emissions.[325]

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[322] *See,* Brookhaven National Laboratory, C.R. Krishna, "Biodiesel Blends in Space Heating Equipment," May 2004, *available at* https://www.nrel.gov/docs/fy04osti/33579.pdf.

[323] *See, e.g.,* Afshin Ghorbani et al., "A comparative study of combustion performance and emission of biodiesel blends and diesel in an experimental boiler," Applied Energy 88(12): 4725-4732, 2011, *available at* https://www.sciencedirect.com/science/article/pii/S0306261911004016; A. Macor and P. Pavonello, "Performance and emissions of biodiesel in a boiler for residential heating," Energy 34(12): 2025-2032, 2009, *available at* https://www.sciencedirect.com/science/article/abs/pii/S0360544208002016; Hamid Momahedi Heravi et al., "The effects of various vegetable oils on pollutant emissions of biodiesel blends with gasoil in a furnace," Thermal Science 19(6): 1977-1984, 2015, *available at* http://www.doiserbia.nb.rs/img/doi/0354-9836/2015/0354-98361500022H.pdf; Danielle Makaire et al., "The use of liquid biofuels in heating systems: A review," 33rd Task Leaders Meeting of the International Energy Agency Implementing Agreement on Energy Conservation and Emissions Reduction in Combustion, 07-11 August 2011, Lund, Sweden, *available at* https://orbi.uliege.be/bitstream/2268/95986/1/TLM_2011_Lund_110711_2.pdf.

[324] The energy content of biodiesel is somewhat lower than that of fuel oil, hence more must be burned to deliver comparable BTUs, and consequently a larger volume of exhaust gas is produced.

[325] U.S. Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, C. A. Miller, "Characterizing Emissions from the

If the mass of NOx emissions per mmBTU of fuel burned is higher for biodiesel than for fuel oil, then using biodiesel blends in thousands of boilers can be expected to increase atmospheric concentrations of NOx and ultimately ozone. Communities in which oil-fired boilers are common would be expected to experience locally elevated ambient levels of these pollutants as a result. Even in the summer months, when boilers are not used for space heating, many customers' use of boilers for domestic hot water would be expected to exacerbate local air-quality conditions, especially in urban communities where this water-heating technology is believed to be more common.[326] Commercial and industrial use of fuel oil to produce process steam and run diesel-fired chillers also would be expected to contribute to the problem. For now, the best available evidence suggests that expanding the use of biodiesel would be likely to exacerbate ambient levels of NOx and ozone and contribute to respiratory health damage, especially in environmental-justice communities that have long borne the brunt of poor air quality and its health impacts.

GHG impact of feedstock – The type of feedstock used in producing biodiesel affects the relative GHG emission reductions associated with using this fuel. While the GHG benefits of employing waste feedstocks are relatively straightforward,[327] the benefits of employing virgin feedstocks such as soy oil are less so. The latter hinge on assessment of GHG emissions across the entire lifecycle of growing crops, processing crops, and shipping crops and oils. Lifecycle analyses, including those cited by biodiesel advocates, point to emissions benefits from biodiesel made with virgin oil – but benefits far less significant than those from biodiesel made with waste feedstocks.[328] The magnitude of biodiesel's GHG benefits, and how they compare with those of other renewable thermal technologies, ultimately is largely dependent on the feedstock. The Department also is cognizant of the potential for use of virgin

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Combustion of Biofuels," 2008, Tables 4 and 5, *available at* https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=191572.

[326] An estimated 34 percent of Connecticut households use fuel oil boilers for domestic hot water. *See*, NMR Group, Inc., David Barclay and Nicole Rosenberg, "R1706 residential appliance saturation survey & R1616/R1708 residential lighting impact saturation studies: Final report," 2019, *available at* https://www.energizect.com/sites/default/files/R1706%20and%20R1616-R1708%20CT%20RASS%20Lighting_Final%20Report_10.1.19.pdf

[327] Attributing the lifecycle GHG emissions to the original virgin product (e.g., cooking oil), the GHG emissions attributable to the subsequent waste product (e.g., waste cooking oil) used as a biodiesel feedstock are low (primarily from local/regional transport and processing of the feedstock).

[328] In California's Low-Carbon Fuel Standard, the Energy Economy Ratio accounts for feedstock, production location, and other factors. The Air Resources Board indicates that, by accounting for such factors, the carbon intensity of biodiesel ranges from around 10 percent of diesel to around 70 percent of diesel. *See* https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities. In the Board's quantitative model for biodiesel carbon intensity, the GHG emissions factor for rendering of virgin soy oil is 3.3 times higher than the emissions factor for rendering of used cooking oil. *See* https://www.arb.ca.gov/fuels/lcfs/ca-greet/tier1-bdrd-calculator-corrected.xlsm?_ga=2.4269299.1309740305.1606832068-1783880760.1605623460.

oil to negatively impact food markets.[329] Notably, Massachusetts's thermal RPS program limits support for biodiesel to fuel made with waste feedstocks.[330]

GHG impact of production location – Oral and written comments and published data provided by biodiesel advocates ultimately do not provide sufficient clarity on an issue central to understanding the environmental benefits of significantly expanded use of biodiesel within Connecticut: the relative proportions of biodiesel consumed in Connecticut that would be produced in-state, produced elsewhere in the Northeast, produced elsewhere in the United States, and imported from other countries.[331] While the lifecycle GHG benefits of biodiesel as compared to those of fuel oil would be significant in any case, it is not clear how the lifecycle benefits of biodiesel would compare to those of other renewable thermal resources. Any benefits would be less significant for biodiesel shipped from outside the region and especially outside North America. Net benefits from reduced emissions of other pollutants – e.g., particulates – also would diminish with distance from manufacture to boiler. The inability to project the likely shape of the biodiesel market in the coming years (although understandable, given the dynamic character of global agricultural and fuel markets) limits the accuracy of projections of the magnitude of benefits that biodiesel can be expected to provide as compared to those provided by other renewable thermal resources, especially over the long term.

Perpetuation of fossil fuel use – Providing a portfolio subsidy for relatively low levels of biodiesel in heating fuel (e.g., B20) would in essence subsidize a product containing *primarily fossil fuel*. Only a schedule of rapid acceleration to very high percentages of biodiesel in Connecticut's fuel oil supply (e.g., B75) would prevent biodiesel subsidies provided via a portfolio standard from, in effect, supporting long-term extensive use of fossil fuels. The Connecticut Energy Marketers Association (CEMA), which represents the state's fuel oil dealers, stated: "We are confident that the potential to transition homes and businesses to B100 … is the future of the deliverable fuel industry." CEMA has publicly committed "to reduce greenhouse gas emissions based on 2001 emissions by a minimum 45% by 2030 and an 80%

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[329] Advocates have argued that manufacturing biodiesel with virgin soy oil (currently one of the principal feedstocks domestically and internationally) does not drive the market for soybeans – and hence does not negatively affect the global food supply and decisions about agricultural land use. However DEEP recognizes that this conclusion ultimately hinges on fossil fuel prices remaining low (a condition that will not necessarily continue to prevail) and demand for biodiesel remaining relatively modest (a condition that biodiesel advocates are actively working to change). It is clear the soy economy is now dominated by markets for protein, rather than markets for fuel, such that manufacturing incrementally more biodiesel with soy oil would not mean impinging on food use of soy oil. But it is not clear that it will remain so indefinitely. National experience with corn-based ethanol as an automotive fuel and international experience with wood as a fuel for electricity generation demonstrate that renewable energy initiatives are capable of dramatically shifting agricultural markets and agricultural land-use decisions and can have significant environmental downsides. Bringing a more holistic, long-term view of biodiesel feedstock markets into focus should be a prerequisite for incorporating biodiesel from virgin feedstocks into a portfolio standard.

[330] Massachusetts Department of Energy Resources, "Biofuels in the Massachusetts' Alternative Energy Portfolio Standard," PowerPoint presentation, February 12, 2018.

[331] *See e.g.,* National Biodiesel Board, "Response to June 24, 2020, Notice of Technical Meeting and Opportunity for Public Comment: Biodiesel as a Thermal Resource," July 8, 2020, p. 2, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/b1ee3fdd1793cba3852585a0005df5d1/$FILE/NBB%20Comments%20-%20CT%20DEEP%20Biodiesel%20Technical%20%207-8-2020%20FINAL.pdf.

reduction by 2050."[332] Regardless of feedstock, production location, and other applicable lifecycle GHG emissions reduction factors, however, 80 percent reduction is currently impractical due to: lack of boiler manufacturer certification of warranties under Underwriter Laboratory protocols expected to be issued in fall 2020; and, more basic, lack of approved ASTM International fuel-quality standards for biodiesel blends beyond B20.[333] Moreover, even among biodiesel advocates there apparently is no consensus on whether burning blends beyond B50 would require relatively minor boiler adjustments or, instead, burner replacement.[334] Until these issues are resolved and a path to deployment of high biodiesel blends across the state's residential and commercial heating sectors is clear, a portfolio standard that includes biodiesel would be premature.

Based on the considerations outlined here, significant questions remain about how scalable emission reductions are for biodiesel blends above B20, given the current lack of ASTM standards for such blends, lack of boiler manufacturer certifications for equipment under Underwriter Laboratories protocols just now being published, and uncertainty about the cost of boiler equipment alterations required. Significant questions also remain about whether more extensive use of biodiesel would reduce or exacerbate NOx emissions – which is a particular concern in environmental justice communities already disproportionately burdened by poor air quality. Significant questions also remain about how biodiesel's GHG benefits compare with those provided by other renewable thermal technologies. And looming over all of these considerations is the reality that, to avoid indirectly subsidizing fossil fuels, T-RPS support for biodiesel would need to fairly quickly be limited to support for very high blend levels. These issues would need to be resolved to determine circumstances under which biodiesel blended into delivered heating oil would be capable of providing meaningful net environmental and social benefits and how these benefits compare with those provided by other renewable thermal technologies.

Thermal RPS as a vehicle for thermal decarbonization

Emissions reductions in the thermal sector needed for Connecticut to achieve its GHG targets will be achieved through a combination of reducing energy losses from the building envelope and transitioning to lower or zero-emission fuels for heating and cooling equipment. As further described in Objective 5

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[332] CEMA, "Biodiesel as a thermal resource," July 8, 2020, p. 1, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/024233f02356cf04852585a0005db990/$FILE/DEEP%20CEMA%20Biodiesel%20as%20a%20Thermal%20Resource.docx.

[333] National Biodiesel Board, "Response to June 24, 2020, Notice of Technical Meeting and Opportunity for Public Comment: Biodiesel as a Thermal Resource," July 8, 2020, p. 15, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/b1ee3fdd1793cba3852585a0005df5d1/$FILE/NBB%20Comments%20-%20CT%20DEEP%20Biodiesel%20Technical%20%207-8-2020%20FINAL.pdf.

[334] *See*, National Biodiesel Board, "Response to June 24, 2020, Notice of Technical Meeting and Opportunity for Public Comment: Biodiesel as a Thermal Resource," July 8, 2020, p. 15, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/b1ee3fdd1793cba3852585a0005df5d1/$FILE/NBB%20Comments%20-%20CT%20DEEP%20Biodiesel%20Technical%20%207-8-2020%20FINAL.pdf, ("[H]aving the flame sensor adjusted … is recommended for blends over B50. Doing so would entail a basic service visit from a heating appliance technician"); *But c.f.*, Sack Energy, "Comments on Biodiesel as a Thermal Resource," July 8, 2020, p. 4, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/fc2892ba91d65bb1852585a40008d307/$FILE/Ct%20TREC%207-13-2020.pdf (for blends beyond B50 "there will be a need of a replacement burner. This can range in price from $650 to $1,800").

herein, Connecticut currently incentivizes building-envelope improvements and, to a lesser degree, electric heat pumps through the C&LM program, the State's utility-administered energy efficiency program. A variety of measures can improve the emissions profile of fuels for heating equipment, including biodiesel blended with heating oil, as well as solar water heating, solar space heating, and renewable natural gas. Other states and jurisdictions have developed, are developing, or are considering initiatives to support some or all of these measures, such as: establishing thermal renewable portfolio standards; developing group-buying programs for renewable thermal equipment; incorporating GHG emissions reduction in utilities' primary cost-effectiveness tests; changing building codes to expand use of renewable thermal technologies; mandating use of this equipment in new government buildings; promoting use of district heating; requiring thermal fossil-fuel utilities and distributors to contribute to energy-efficiency funds; instituting low-carbon thermal fuel standards; instituting carbon taxes on thermal fuels; and prohibiting new natural-gas hookups.

Public Act 19-35 requires this IRP to consider only one option: adoption of a thermal RPS. The Department believes the two primary paths for employing the existing RPS as a vehicle for a thermal RPS would be detrimental.

T-RPS as an expansion of existing RPS – A thermal RPS *expanding* Connecticut's existing RPS – that is, imposing a thermal obligation on top of existing electric obligations – would increase the price of electricity. It would place an additional regulatory compliance obligation on electricity suppliers, who would pass compliance costs on to electricity customers in the form of higher rates. Under this scenario, a subsidy for heating-oil retailers would be supported by electricity ratepayers. In essence, customers heating with electric technologies would subsidize customers heating with fossil fuels. This cross-subsidization would have three negative policy consequences:

- It would undermine other Connecticut climate policies, including electrification of vehicles and adoption of electric heat pumps, by making these technologies more expensive to operate.
- It would exacerbate the problem that Connecticut electric ratepayers already face the highest electricity prices in the continental United States as well as rising consumer utility expenses (due in part to escalating, climate-driven summer consumption of electric cooling[335]).
- It would exacerbate the challenges of the economic downturn prompted by the COVID-19 pandemic, in which affordability of electricity is already an acute problem.

Requiring customers of Connecticut's two investor-owned electric utilities[336] to financially support non-electric resources in a T-RPS also would thwart the principle of cost causation: it would make electric ratepayers responsible for subsidizing the use of fuels that are unrelated to electricity generation, transmission, and distribution. The costs of compliance with the thermal RPS would be passed on to electric ratepayers in the form of higher electric (generation) rates. Meanwhile fossil fuel suppliers, who have no compliance obligation under the existing RPS (and are subject to no thermal-sector carbon tax), would financially benefit from this arrangement by enjoying a subsidy disproportionately supported by

[335] DEEP analysis of National Weather Service temperature data from the weather station at Bradley Airport indicates that between 1905 and 2019, the prevalence of "cooling degree days" increased from ~640 to ~870 annually and the prevalence of days of 90˚ F. or higher increased from ~8 to ~23 annually.

[336] As further described in Objective 1, only the two investor-owned utilities, Eversource and United Illuminating, are subject to Connecticut's RPS requirements. Customers of the state's municipally owned utilities are not.

ratepayers other than their own retail customers. In contrast, a program based on the principle of cost causation would equitably distribute these costs among all thermal providers – electric, oil, gas, and propane – in proportion to the fossil-fueled thermal energy they provide.

The National Biodiesel Board has argued that it would be cheaper for electricity ratepayers as a whole to subsidize the use of biodiesel through a thermal RPS program than to support expanded electric generation and distribution for broad use of electric heat pumps.[337] It is not clear that this is so. The next Comprehensive Energy Strategy will explore a policy for broad deployment of heat pumps, and only at that point will there be a firm basis for understanding the likely scope and pace of statewide heat pump deployment. At the same time, the various grid-modernization proceedings PURA is conducting are weighing new rate structures and demand-response programs, and DEEP is investigating demand-response programs within the C&LM Plan, all of which could reduce or offset the grid impacts of heat pumps. Only as this work is completed will there be a firm basis for understanding how much pressure broad deployment of heat pumps would be likely to place on grid infrastructure and electricity prices.

T-RPS as carve-out within existing RPS – Some biodiesel advocates have suggested that a thermal RPS should be structured as a carve-out *within* Class I of the existing RPS. The carve-out approach would help to mitigate incremental costs of the program, because it would not place additional compliance obligations on electricity suppliers. However, it would undercut traditional RPS support for needed expansion of renewable resources on the electric grid. The Class I obligation is scheduled to escalate from 21 percent in 2020 to 40 percent in 2030 in order to vigorously push the region's electricity-generation fleet toward clean technologies.[338] (More information on Connecticut's RPS is provided in Objective 2.) Shifting part of that obligation to non-electric resources such as biodiesel inevitably would diminish the program's market support for zero-carbon electricity, which in turn would reduce the carbon-emissions-reduction benefit of thermal and transportation electrification – undermining the central decarbonization strategy envisioned by the Governor's Council on Climate Change.[339]

Conclusion

In light of the concerns outlined here, a thermal RPS should not be created in Connecticut to support biodiesel blended into fuel oil at this time. If there were a desire to support the biodiesel industry despite these concerns, in keeping with principles of cost causation, support for biodiesel to reduce GHG emissions associated with delivered fuel oil should be provided not by electricity ratepayers, but by delivered fuel oil suppliers and their customers. A pilot program first should be conducted to monitor

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[337] National Biodiesel Board, "Response to June 24, 2020, Notice of Technical Meeting and Opportunity for Public Comment: Biodiesel as a Thermal Resource," July 8, 2020, p. 22, *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/b1ee3fdd1793cba3852585a0005df5d1/$FILE/NBB%20Comments%20-%20CT%20DEEP%20Biodiesel%20Technical%20%207-8-2020%20FINAL.pdf.

[338] Connecticut Renewable Portfolio Standard, *available at* https://portal.ct.gov/PURA/RPS/Renewable-Portfolio-Standards-Overview.

[339] The Council sees decarbonization of the electricity sector as the linchpin of decarbonization in the transportation and thermal sectors. *See* Building a Low-Carbon Future for Connecticut, 2018, https://portal.ct.gov/-/media/DEEP/climatechange/publications/BuildingaLowCarbonFutureforCTGC3Recommendationspdf.pdf.

ambient NOx concentrations in urban areas with a high density of biodiesel-fired boilers. All standards, protocols, and certifications needed for high-biodiesel blends (e.g., B75 or higher) and their widespread use would need to be in place prior to any significant commitment to support biodiesel deployment. And it would be advisable to restrict allowable feedstocks to waste food oils and greases, as in the Massachusetts program. In the process, the State should consider whether public policy aims relating to biodiesel could be achieved at lower cost by instead merely imposing a statewide biodiesel blending mandate to replace the mandate established by Conn. Gen. Stat. § 16a-21b.[340]

In the upcoming Comprehensive Energy Strategy process, DEEP will conduct a comprehensive exploration of mechanisms – including carbon pricing, low carbon fuel standards, and a thermal RPS – to support transformation of the thermal sector, inclusive of all viable renewable thermal measures, not just biodiesel. Any mechanism established in Connecticut should adhere to the principle of cost causation, distributing the cost of subsidies equitably among the parties in proportion to their carbon emissions. It should avoid driving up electricity costs. And it should not come at the expense of diminishing the existing RPS program's incentives for clean electricity.

With respect to a thermal RPS in particular, the Comprehensive Energy Strategy will explore a number of other design factors:

- breadth of the array of renewable thermal technologies that should be included;
- whether the state should establish a formal target for deployment of renewable thermal technologies;
- whether metering should be required for all technologies in all contexts;
- whether RECs should be tradeable;
- whether priority should be given to technologies producing zero emissions at point of use;
- whether woody biomass should be included, and, if so, how the resulting air-quality impacts should be regulated;
- how the value of Alternative Compliance Payments should be established; and
- how such a program should be structured so that the administrative burden on state agencies would be manageable.[341]

Reviewing these and other issues raised in stakeholders' written and oral comments, the Comprehensive Energy Strategy will make a recommendation on whether a comprehensive T-RPS or other program reflecting cost causation and supporting resources based upon sound evidence of relative GHG reduction benefits should be established and, if so, how it should be designed. For now, this IRP recommends against creation of a T-RPS that subsidizes non-electric technologies within the existing, electricity-ratepayer-funded RPS.

[340] Conn. Gen. Stat. § 16a-21b(b)(1) imposes a biodiesel blending requirement for heating oil sold in Connecticut (minimum of 20 percent biodiesel as of July 2020) contingent on New York, Massachusetts, and Rhode Island adopting equivalent legislation. This requirement has not been implemented as only Rhode Island has adopted equivalent legislation.

[341] DEEP, "Renewable Thermal Portfolio Standard Programs in New England States," Nov. 2019, http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/47469b57e3d1a355852584c40070531d/$FILE/Background.pdf.