

The PPA Crutch

**The Implications of Renewable Energy
Power Purchase Agreements in New England**
*Lessons Learned from Public Utility Regulatory
Policy Act Independent Power Producers*

Master of International Business Thesis

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Executive Summary

The proliferation of long-term, fixed-price contracts, known as Power Purchase Agreements (PPAs), for renewable energy in a context of decreasing prices may pose unanticipated obstacles for New England's electric power sector. The amount of electricity the region generated from such renewable sources as wind and solar has increased by a third between 2010 and 2015 due to falling technology costs and supportive policy.¹ This growth has resulted in an increase in the share of electricity generation under PPAs from 6% in 2010 to 9% in 2015 and, if New England achieves its Renewable Portfolio Standard (RPS) requirements, 17% in 2020.² Simultaneously, the price of these PPAs has been dropping: U.S.-wide average wind prices decreased from \$60 per megawatt hour (MWh) in 2010 to \$20 per MWh in 2014, while solar fell from \$150 per MWh in 2010 to \$50 per MWh in 2015.^{3 4} As renewable energy PPA prices consistently decrease, they render the electricity contracted under older PPAs uncompetitive. If New England meets its RPS targets and PPA prices continue to drop by 22% per year, the region will have locked in a net present value of \$595 million in costs above market prices for renewables in the next five years alone.⁵ These "stranded costs" will eventually have to be accepted by either the shareholders of the power producers, the shareholders of the offtakers, ratepayers, or taxpayers. This promises to be a contentious issue that must be recognized today.

The current situation has strong parallels with the debate over the integration of Independent Power Producer (IPP) PPAs, which resulted from the Public Utility Regulatory Policy Act (PURPA) of 1978, into wholesale markets upon the deregulation of the electric power sector in the 1990s. As such, some of the strategies that were successful then may be helpful now for different stakeholders. The offtakers, such as utilities, that are locking into these long-term liabilities must recognize the looming risk, and act to either minimize the number of PPAs they sign or to mitigate the negative consequences through shorter agreements, contract buyouts, or voluntary renegotiations. While power producers benefit from these long-term contracts in the short term, they may need to worry about their competitiveness or their customers' creditworthiness in the long term as the risks of PPAs become apparent. They should therefore consider buyouts or renegotiations of existing contracts, and develop innovative new PPA structures that minimize the identified tensions. New England state policy makers should consider establishing voluntary contract renegotiation mechanisms, incrementally adjusting subsidies and regulations to keep PPA prices steady, regulating the length of PPAs, or even passing on stranded costs to taxpayers. Regardless, all of the stakeholders must proactively address this issue if they want to avoid a deadlock similar to the stranded-cost debate of the 1990s, and pave the way to a cheap, clean, and reliable electric power system.

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List of Acronyms

C&I	Commercial and Industrial
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
GWh	Gigawatt Hour
IOU	Investor-Owned Utilities
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt Hour
LCOE	Levelized Cost Of Energy
MWh	Megawatt Hour
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policy Act
REC	Renewable Energy Certificates
RFP	Request For Proposals
RPS	Renewable Portfolio Standard

Introduction

In 2010, long-term contracts to buy solar power were \$150 per megawatt hour (MWh). In 2015, new 20-year contracts were \$50 per MWh. In 2020, the price will be even lower. While the decrease in renewable energy prices has been impressive, the linkage of these prices to long-term contracts poses challenges. How will utilities that in 2010 committed to rates that are now above market pay for those commitments over the next two decades? How will power producers who depend on those utilities to be continuing and creditworthy customers be impacted? How will policy makers who are charged with overseeing the provision of cheap, clean, and reliable power resolve this issue?

There has been much debate about the impact of renewables on the operation of New England's grid, but almost no discussion of the effects of the associated long-term, fixed-price contracts known as Power Purchase Agreements (PPAs). The goal of this paper is to examine the implications of, and potential approaches to dealing with, the increasing number of utility-scale renewable energy PPAs in the New England market. It will do so by studying the integration of Public Utility Regulatory Policy Act (PURPA) Independent Power Producer (IPP) PPAs into wholesale markets after the deregulation of the electric power sector in the 1990s.

The paper commences by providing a brief history of the electric power system in the United States. It then characterizes New England's power system and several of its main challenges. New England is chosen for this study because of its deregulated market and relatively high penetration of renewables.

The paper then traces the growth of renewables in New England due to supportive policy and decreasing technology costs, and, importantly, identifies the resulting increasing quantity and decreasing price of PPAs. Next, the paper

examines the issues caused by the proliferation of these long-term contracts, such as stranded costs and decreased scope for competition.

To understand the implications of an increased number of PPAs in the context of decreasing prices, the paper turns to a similar example from several decades ago: the integration of the PURPA IPP PPAs into new wholesale markets. PURPA had encouraged a similar proliferation of PPAs in the 1980s, which created problems when the deregulation of the electricity market in the 1990s caused the industry to expect a decrease in market prices; no utility wanted to be left with the stranded cost of the now-expensive PPAs they had been caused to sign. The paper examines some of the issues caused by these PPAs, and outlines various strategies stakeholders employed to deal with those problems.

The paper then discusses the similarities and differences between the historical PURPA IPP PPA example and the present renewable energy PPA issue, in order to identify lessons learned and applicable strategies. Finally, the paper offers recommendations for utilities, power producers, and policy makers.

Context

United States' Power System History

For most of the 20th century, electricity was produced and distributed by vertically integrated utilities in the United States. The government granted these monoliths “natural monopolies” over their service territories to avoid multiple companies building duplicative infrastructure, thus minimizing the cost to serve customers. In exchange for this concession, these utilities agreed to be closely regulated by public utility commissions, which set tariffs and approved system planning.⁶ This system worked well in expanding the electricity grid throughout the United States, but by the 1970's, the lack of competition in the industry was starting to take its toll on service quality and cost.⁷

To introduce competitive pressure and encourage the use of renewable energy, the U.S. Congress passed PURPA in 1978. This legislation required utilities to purchase electricity from IPPs at or below the avoided cost of the utilities generating it themselves.⁸ This electricity was usually purchased through PPAs, which often lasted 25 to 30 years.⁹ While these contracts were relatively long-term and inflexible, PURPA effectively introduced a modicum of competition, and began to break up the utilities' long-held monopoly on the production of power.

Only in the 1990s did deregulation open the way to fully competitive spot markets for electricity. The Energy Policy Act of 1992 created a category of competitive wholesale suppliers and allowed the Federal Energy Regulatory Commission (FERC) to open the transmission network to them.¹⁰ In 1996, FERC Orders 888 and 889 mandated non-discriminatory access to the grid, leading to the creation of Independent System Operators (ISO) to implement and manage competitive wholesale markets.¹¹ Today, there are seven ISOs in the United States that serve the FERC's requirement of providing generators open access to transmission.¹²

New England's Power System Characteristics

The power system that serves Massachusetts, Connecticut, New Hampshire, Rhode Island, Maine, and Vermont is composed of a wholesale market and transmission network with an ISO, as well as distribution and retailing companies.

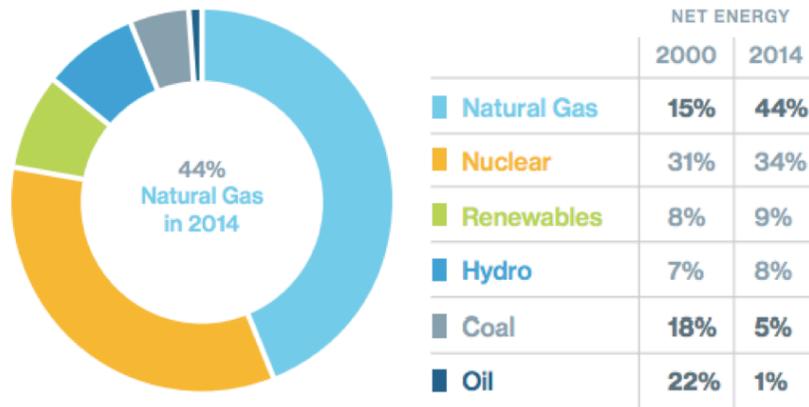
New England's wholesale market is managed by the Independent System Operator of New England (ISO-NE), which is regulated by FERC.¹³ The market includes over 400 buyers and sellers of electricity, who traded \$10.5 billion in wholesale electricity in 2014.¹⁴

Independent System Operator of New England and Control Centers Map¹⁵



The region's 350 generators currently operate 31 GW of capacity, with another 12 GW proposed.¹⁶ In 2014, New England's energy was generated from 44% natural gas, 34% nuclear, 9% renewables, 8% hydro, 5% coal, and 1% oil, as outlined in the figure below.¹⁷ This system serves 6.5 million households and businesses, which generate a demand that has peaked at 28 GW and is forecasted to grow by 1% annually.¹⁸ In 2014, the demand was mostly residential (38.8%) and commercial (37.3%), with industrial at 23.5%, and a small amount for transportation (0.3%).¹⁹

New England Power Production Mix (2014)²⁰



The electricity from the wholesale market is carried via 8,500 miles of high-voltage transmission lines that stretch across the region.²¹ There has been \$6.6 billion in transmission investment in the last decade, and another \$4.5 billion is planned in the next three years, including for proposed projects to access carbon-free energy.²² The system has 13 interconnections with neighboring regions, including New York and Eastern Canada, over which it imported 16% of energy needs in 2014.²³

This system, which has operated successfully for over a decade in its current form, is faced with several challenges, discussed below.

New England’s Power System Challenges

According to ISO-NE, the key factors affecting the performance of New England’s power system resources and grid reliability are natural gas infrastructure constraints, power plant retirements, and renewable energy resource integration.

Natural Gas Infrastructure Constraints

Between 2000 and 2014, the share of electricity produced from natural gas increased from 15% to 44%, at the expense of coal (18% down to 5%) and oil (22% down to 1%).²⁴ Further, natural gas makes up 57% of all the new generation capacity that is requesting interconnection with the grid.²⁵ While this shift in New England's generation mix has resulted in falling average emissions rates for nitrogen oxides (66%), sulfur dioxide (94%), and carbon dioxide (26%), it has created new constraints for the system.²⁶

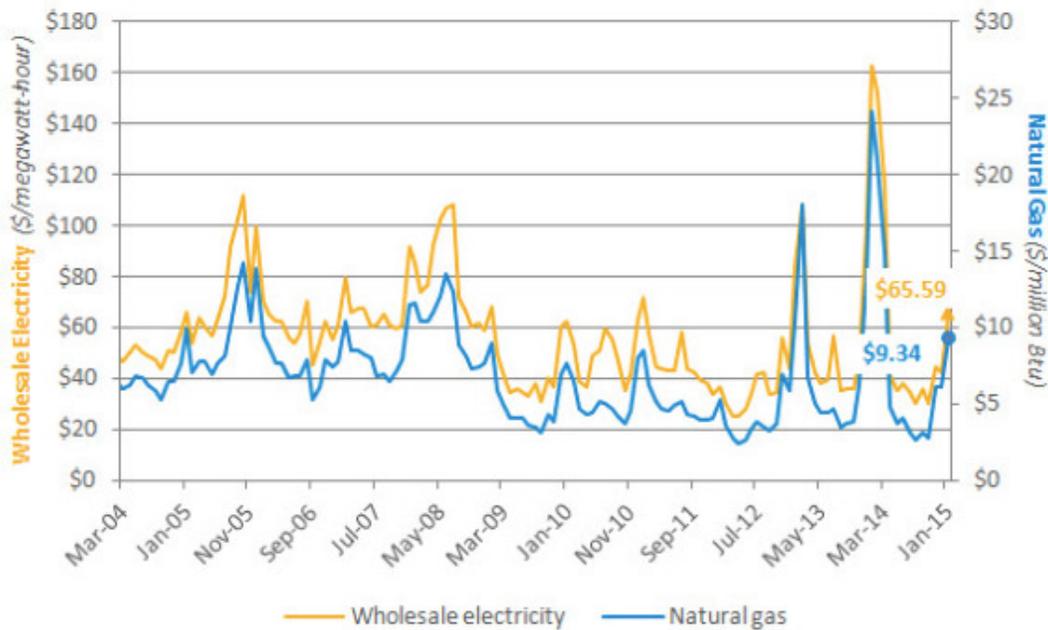
The current infrastructure to supply the gas required for the gas-powered generation is inadequate. The vast majority of New England's gas supply comes via pipeline from the continental United States, particularly from the nearby Marcellus Shale. Unfortunately, there is "only so much space on a pipeline," and the priority goes to customers who have signed long-term contracts for the gas, which are usually the local natural gas distributors.²⁷ As a result, natural gas generators are generally able to source their inputs on a day-to-day basis from these distributors but, especially in cold winter months when most gas is used for heating purposes, this supply is not guaranteed.

Furthermore, the means to avoid this bottleneck are limited. Some generators are able to use liquefied natural gas, which allows them to circumvent the constrained pipelines, but this tends to be four to five times more expensive.²⁸ Storing gas for use during periods of scarcity is not a sufficient option because most plants have little to no on-site storage for gas.²⁹

This dependence on natural gas, as evident in the linked gas and electricity prices in the figure below, has several related negative impacts on the electric power system.³⁰ The system's reliability is decreased due to its reliance on such an interruptible resource. This variability in the supply of natural gas leads to

price spikes, especially in the winters. These spikes, in turn, lead to the emergency use of oil- and coal-powered plants, which increases regional air emissions.

Wholesale Electricity and Natural Gas Prices³¹



This dependence on natural gas generation and constrained supply also poses problems for the integration of renewable and distributed generation resources. Electricity generation from wind and solar resources is inherently variable and, in the absence of significant amounts of electricity storage or demand response capacity, requires flexible back-up generation technologies to ensure grid reliability. Without sufficient gas-based generation to fill this role, the operator must turn to other sources, including coal plants.

Power Plant Retirements

While 12 gigawatts (GW) of new capacity is proposed, more than 3.5 GW of ISO-NE’s generation capacity is set to retire by 2018. Mostly coal- and oil-powered,

these plants are facing decreasing utilization and are unable to recover the investments necessary to continue operating.³² Additionally, licenses for 2 GW of hydropower will expire between 2014 and 2022, and new environmental considerations could decrease the flexibility of their operations.³³

Generation Retiring or At Risk³⁴

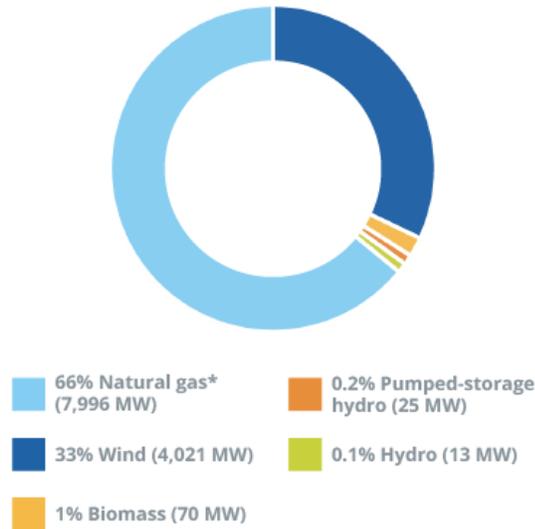


These retirements have several negative impacts, such as further increasing the power system's reliance on the constrained gas generation. It could also result in insufficient resources for the region's forward capacity market, increasing the auctions' prices as natural gas supply decreases.³⁵ Finally, the regulation and reserve functions provided by the hydro plants were crucial in the integration of renewable resources into the energy system; as a fully dispatchable power source, hydro is well suited to offset the intermittency of renewables.

Renewable Energy Resource Integration

Non-hydro renewable resources generated 9% of New England's electricity in 2014.³⁶ Looking ahead, wind energy generation provides a third of the proposed new capacity in New England.³⁷

*New England Generation Capacity Proposal Pipeline (2015)*³⁸



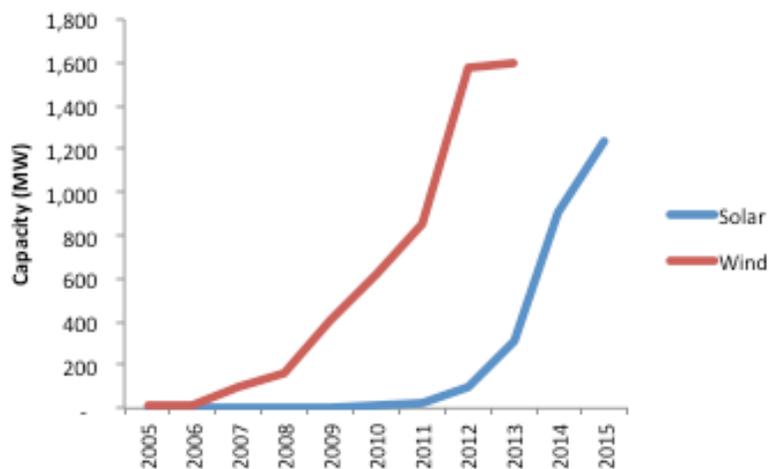
These added renewable resources, while beneficial for environmental goals, pose several difficulties for operating the grid.³⁹ By their very nature, the variability of wind and solar energy's output makes it hard for the operator to plan the dispatch of supply. Wind and solar also have a limited ability to serve peak loads at different times of the year, due to less wind in the summer and less sunshine in the winter. Finally, the system occasionally cannot absorb all the electricity generated by these resources, causing the operator to curtail them.

Problem Analysis

Renewable Energy in New England

Despite the technical difficulties of integrating wind and solar, these technologies have been growing by leaps and bounds in New England during the last decade; from negligible levels in 2005, wind power capacity had grown to 1,600 MW in 2013 and solar to 1,233 MW in 2015, as illustrated in the chart below.⁴⁰ This rapid growth is due to a favorable policy environment and falling costs.

New England Wind and Solar Capacity Growth⁴¹



Favorable Policy Environment

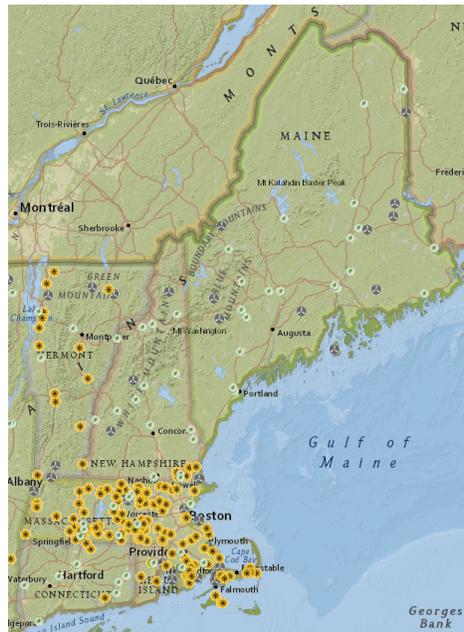
Renewable energy technologies have been encouraged by regulations, tax credits, subsidies, and other policies. This increased emphasis on renewable energy sources has grown as the public and politicians have increasingly understood the environmental, as well as geopolitical and economic, impacts of our energy system. The growing social and political support driving these policies is apparent in climate marches throughout the country and, more recently, the international agreement at the December 2015 United Nations Climate Change

Conference in Paris. Some of the most significant policies, both at the federal and state level, are discussed below.

At the federal level, the Production Tax Credit (PTC) and Investment Tax Credit (ITC) have been some of the primary driving forces of renewable energy throughout the United States. These credits were available under 26 U.S. Code § 45 and § 48, and were expanded significantly under the American Recovery and Reinvestment Act of 2009.^{42 43} The ITC allows businesses across the United States to receive a 30% tax credit for any investment in renewable energy systems, though it is mostly used for solar. That is, installation of a \$1 million solar system results in a \$300,000 tax credit. This is a significant incentive, which Congress has extended through 2020. The PTC is a similar policy, though it provides a tax credit based on ongoing production levels, instead of just the up-front investment, and is mostly used for wind projects.

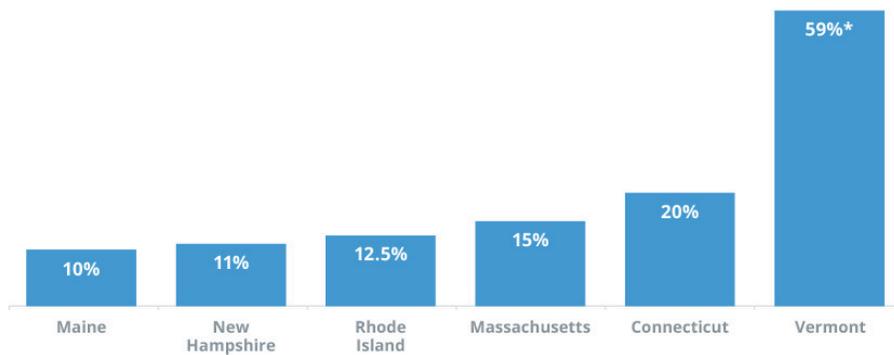
Other federal policies have also helped bolster investment in renewables in the United States. For example, the Modified Accelerated Cost-Recovery System provides accelerated depreciation tax treatment for renewable energy assets.⁴⁴ In other words, the value of a capital investment in a wind or solar installation can be depreciated more rapidly, creating tax shields earlier, which is valuable in terms of the time value of money. This treatment is helpful for renewable energy assets, which have relatively much higher up-front fixed costs than do traditional energy sources, which have ongoing and variable fuel costs. The federal government also provides loan guarantees to help finance demonstration projects, helping newer renewable energy technologies reach the deployment stage.

Map of New England Renewable Energy Installations⁴⁵



At the state level, New England has some of the most progressive and supportive policies in the country. All six New England states are among the 29 states with Renewable Portfolio Standards (RPS), which set requirements for the amount of renewable energy consumed on the grid.⁴⁶ Under this policy, Investor-Owned Utilities (IOU) are required to source a certain percentage of their electricity supply from renewable sources, either by generating it themselves or by purchasing Renewable Energy Certificates (REC) minted for each MWh of renewable energy produced by someone else. New England states' RPS targets for 2020 range from 10% in Maine to 59% in Vermont, as outlined in the figure below. Most states' RPS systems are technology agnostic, though some states provide extra credit for solar energy, such as in Massachusetts, resulting in relatively more of this type of generation than in other states, illustrated in the map above.⁴⁷ Unlike many other policies that focus on improving the economics of renewable energy projects, RPSs are significant because they create a demand for these clean assets.

New England's Renewable Portfolio Standards for 2020 (Class I Systems)⁴⁸



* Vermont's Renewable Energy Standard has a total renewable energy requirement (reflected above), which recognizes large-scale hydro and all other classes of renewable energy.

Another important policy adopted by all of the New England states is net metering. This regulation makes it possible for owners of renewable energy assets to sell surplus power to the grid at retail rates. Connecticut and Maine have no limit to the amount of distributed generation that can be connected to the grid and be eligible for net metering credits.^{49 50} The other four states have net metering caps that limit the amount of renewable electricity that can be sold under this program, ranging from 50 MW in New Hampshire to 35% of peak load in Rhode Island. Periodic increases to these caps are hotly debated in legislatures and the media.^{51 52 53} Net metering policies not only guarantee that renewable energy assets have access to a market and a mechanism of being compensated, but also provide the additional incentive of being compensated at the retail rate, which is much higher than the wholesale rate most generators receive.

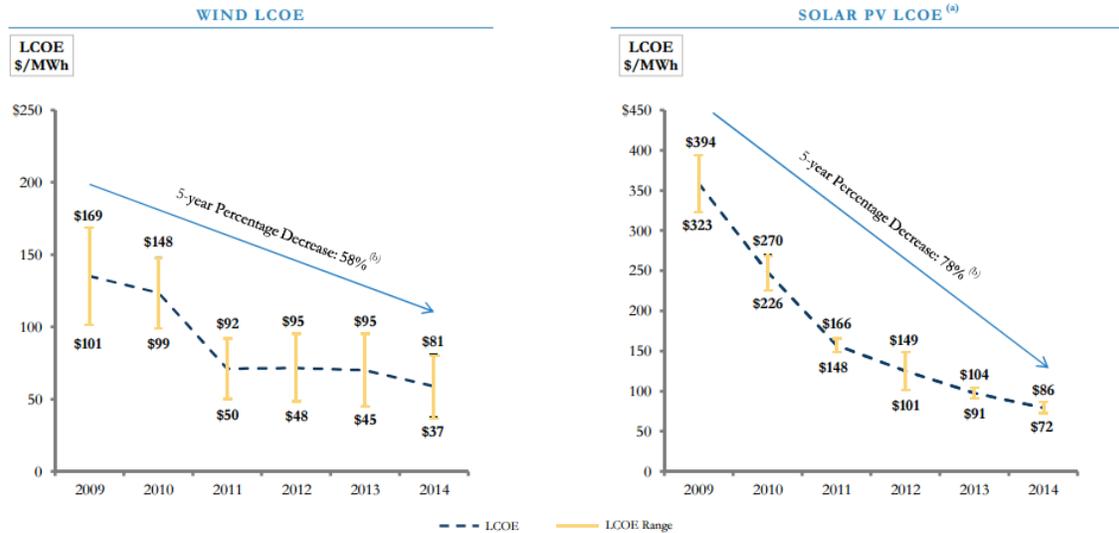
Beyond these foundational policies, the states in New England provide other incentives to promote renewables. Many have property tax exemptions, which preclude renewable energy owners from having to pay increased taxes on the value added by a generation asset, or sales tax exemptions, which negate sales taxes on the purchase of the system.⁵⁴ Some, such as New Hampshire, have renewable rebate programs that will reimburse \$0.75 per watt up to 50% of the

cost of the system. Vermont will even guarantee payment of a feed-in tariff for 10 to 25 years through its Standard Offer Program.⁵⁵ These types of policies have been key to making New England one of the most attractive markets for renewable energy investment in the United States, and therefore one of the best regions to take advantage of the consistently decreasing system costs.

Falling Renewable Energy Costs

The installed costs for wind and solar have dropped drastically, partially as a result of the economies of scale resulting from the policies discussed above and investments in innovation. The Levelized Cost Of Energy (LCOE) for utility-scale wind power dropped by a factor of six between 1980 and 2000, and decreased another 58% between 2009 and 2014 to around \$60 per MWh.^{56 57} At these prices, wind energy is cheaper than many other sources of energy and is often competitive with natural gas, which has an LCOE between \$52 and \$96 depending on fuel costs.^{58 59} This has contributed to a tripling of wind power capacity in the United States between 2008 and 2014.⁶⁰ In New England, wind LCOEs can be slightly higher than the nationwide average, usually between \$55 and \$81 per MWh.⁶¹

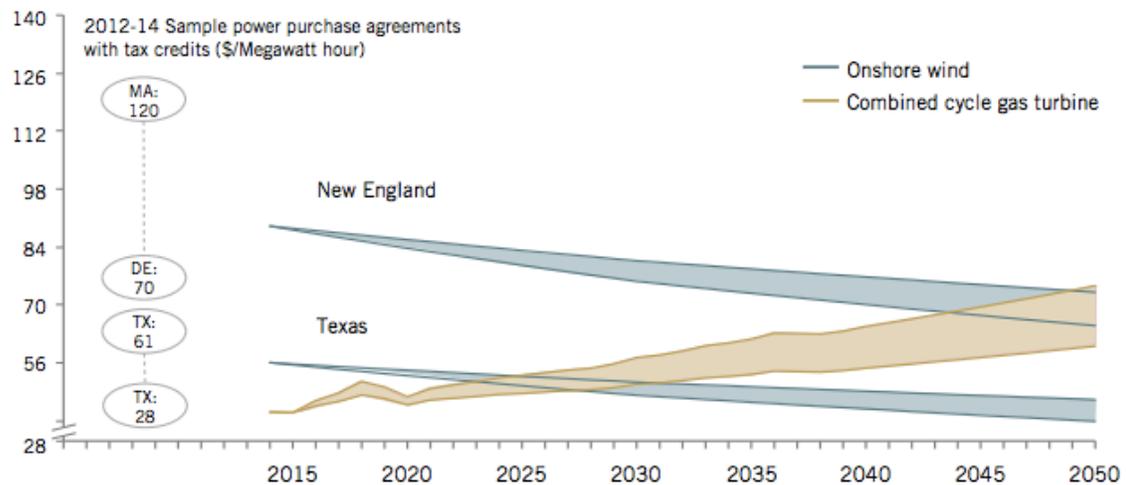
Falling Costs: Historical U.S. Utility-Scale Wind and Solar LCOE⁶²
 (New England Specific Data Not Available)



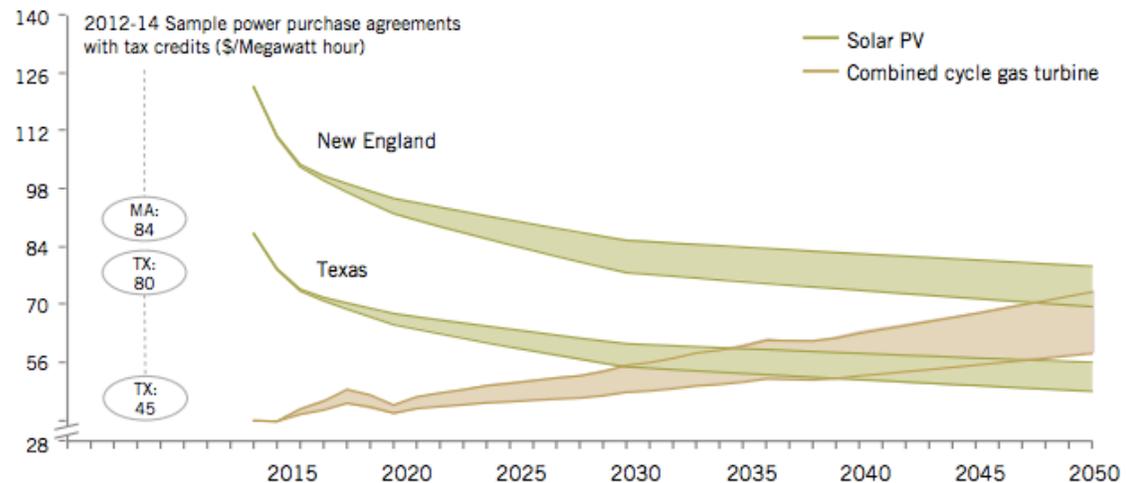
The LCOE for utility-scale solar power has fallen even more significantly in recent years; between 2009 and 2014 the cost of solar power decreased by 78% to around \$80 per MWh.⁶³ The ability to achieve year-on-year cost savings in solar continues to impress. Looking forward, some optimists even go so far as to predict a “solar singularity”, in which the technology would be so inexpensive that it would become the new default power source.⁶⁴ Utility-scale solar LCOEs in New England are higher than in the rest of the country, due to less optimal solar resources, and can vary from \$100 to \$221 per MWh.⁶⁵

Falling Costs: Projected New England Utility-Scale Wind and Solar LCOE⁶⁶

Average unsubsidized onshore wind LCOE (\$/Megawatt hour)



Average unsubsidized solar PV LCOE (\$/Megawatt hour)



While the estimates of LCOE vary significantly across regions and across different reports, the trend is clear: the cost of renewables is dropping considerably. As illustrated in the charts above, LCOEs for both wind and solar in New England are projected by the Harvard Business School to continue dropping. These declining costs, paired with favorable energy and environmental policies, will facilitate the growth of renewable energy technologies throughout the country and especially in New England.

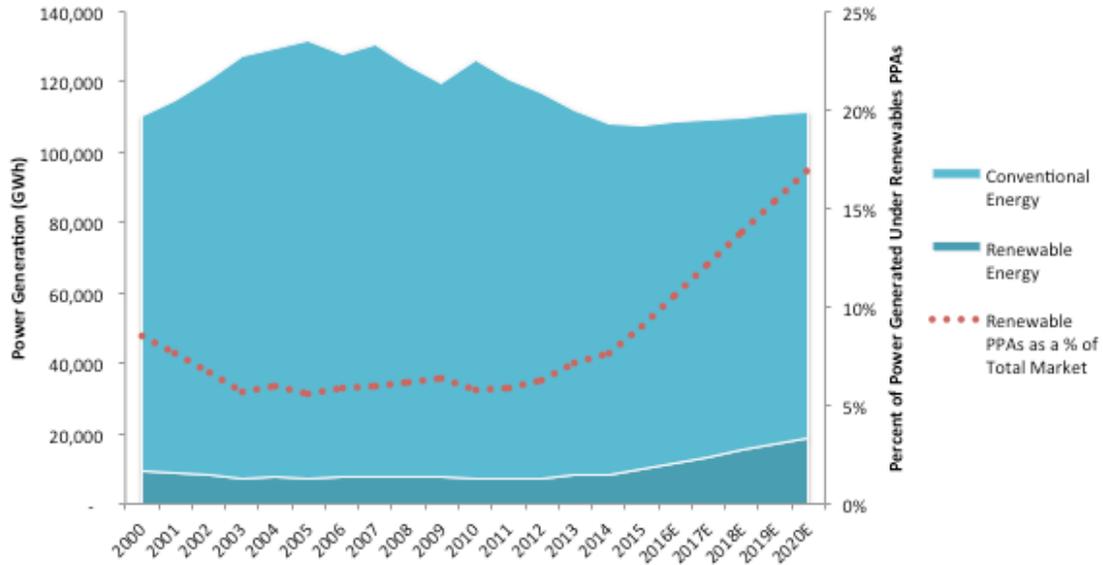
Power Purchase Agreements for Renewable Energy in New England

PPAs are one of the most common means of buying and selling renewable energy. These long-term, fixed-price, take-or-pay contracts guarantee that offtakers such as utilities will pay power producers a set price for electricity for 20 to 30 years. This type of agreement is a key risk-mitigation mechanism that enables project developers to access the financing necessary to build the installations. This arrangement is also beneficial for the offtakers, like utilities, because they can avoid the high up-front investment cost and uncertain maintenance costs associated with owning renewable energy assets themselves. Recently, New England has experienced an increase in the quantity of renewable energy PPAs and a decrease in their prices, with both positive and negative implications, discussed below.

Increasing Power Purchase Agreement Quantity

The increase in renewable energy capacity in New England has resulted in a commensurate proliferation of PPAs. Assuming that the New England states will reach their RPS targets and that the projects will employ PPAs, there will be 18,916 gigawatt hours (GWh) per year of renewable energy contracted under PPAs by 2020, as displayed in the figure below.⁶⁷ As such, 17% of New England's electricity would be generated under long-term contracts for renewables, up from 9% in 2015 and 6% in 2010. Having such a significant proportion of the states' electricity production tied to long-lasting agreements for renewables could have both positive and negative impacts on the electricity market.

New England Renewable Energy Power Purchase Agreements⁶⁸



There is no guarantee that the New England states will meet their RPS goals, which could potentially be frustrated by physical or political constraints. As discussed, there is a continuing debate about how much renewable energy can be integrated into the grid due to the intermittency of renewables. The growth of renewable energy is not only dependent on its cost and supporting policies, but also on transmission constraints, the availability of back-up power or storage, and other factors that affect the flexibility of the grid. Additionally, the goals or implementation of the policies could always change based on the states' politicians. For example, the Massachusetts governor elected in November 2014 is less of a proponent of renewables than the previous governor, as evidenced by the decrease in supportive policies: as of February 2016, he has not increased caps for either the amount of renewable energy that can be sold to the grid via net metering or the number of RPS RECs distributed to generators.⁶⁹

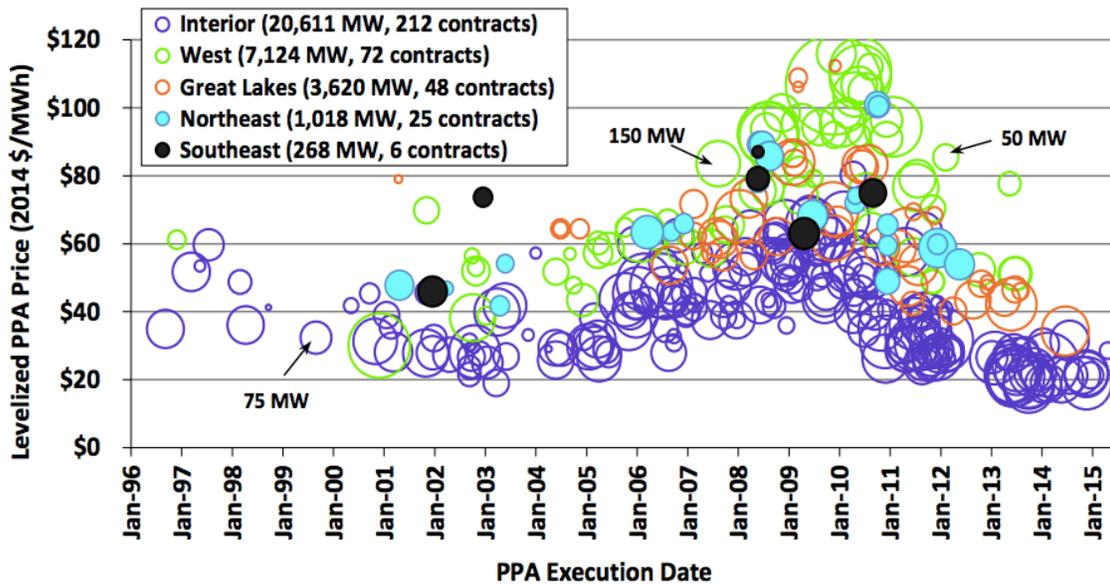
Nevertheless, the New England states seem to be pushing ahead with meeting their renewable energy targets. In November 2015, for example, Connecticut, Massachusetts, and Rhode Island issued a joint Request For Proposals (RFP)

seeking additional renewable energy production. While Rhode Island did not specify the amount of renewables it was looking to procure, Connecticut and Massachusetts sought an additional 5,067 GWh per year at fixed prices, representing 8% of their 2014 generation.⁷⁰ Based on New England's past performance and its future commitments, it seems likely that the renewables, and hence the long-term contracts associated with them, are on the rise.

Decreasing Power Purchase Agreement Prices

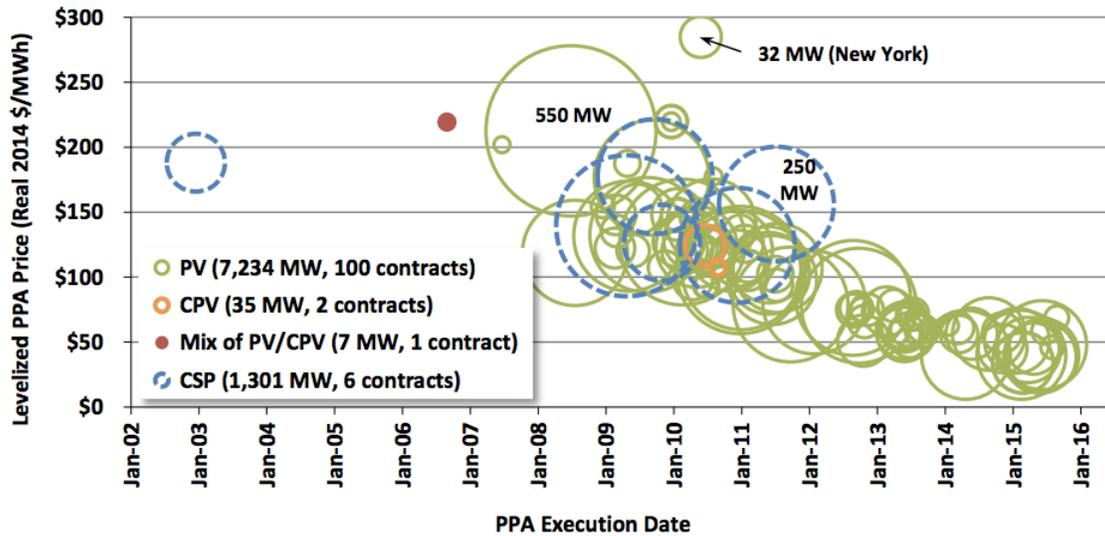
In the face of decreasing costs, supportive policy, and a competitive marketplace, renewable energy PPA prices have also been dropping. While the average wind PPA nationwide in 2010 was over \$60 per MWh, it had dropped to just over \$20 per MWh by 2014.⁷¹ This decline is due to declining turbine costs, except for a brief increase between 2005 and 2010 due to premature scale-up of the technology. Since 2013, these wind PPAs have been less expensive than just the variable costs of existing natural gas plants, not to mention the additional fixed costs of new ones. Wind PPA prices in New England tend to be higher than the national average, but have still dropped from \$80 per MWh in 2010 to \$55 per MWh in 2012, as illustrated in the figure below.⁷²

Falling Prices: Utility-Scale Wind Power Purchase Agreement Prices⁷³



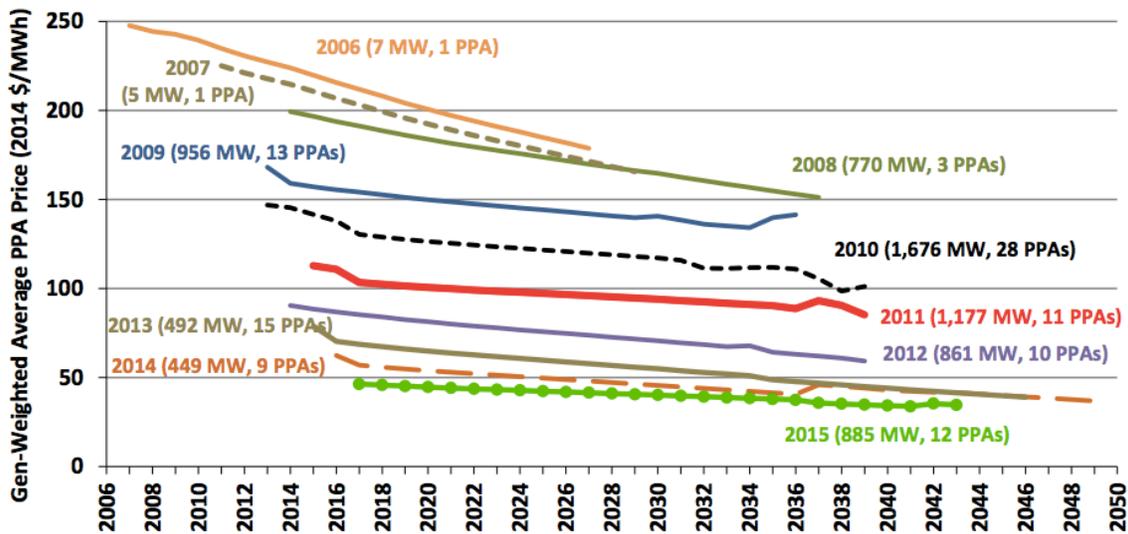
Solar PPA prices have dropped even more drastically. As indicated in the figure below, prices have dropped from around \$150 per MWh in 2010 to less than \$50 per MWh in 2015, and are sometimes even priced as aggressively as \$40 per MWh.⁷⁴ The vast majority of the solar capacity included in that sample is located in the southwest of the country, where solar energy is more abundant than in New England. That said, some solar PPA prices in Massachusetts have fallen as low as \$50 per MWh in 2015.⁷⁵

Falling Prices: U.S. Utility-Scale Solar Power Purchase Agreement Prices⁷⁶



With such rapidly decreasing renewable energy PPA prices, the real competition may come from within the renewables industry rather than from conventional fuels. As shown in the figure below, solar PV PPAs are more and more attractive year after year. These levelized real PPA prices fell consistently each year by almost \$25 per MWh between 2006 and 2013, and by around \$10 per MWh in 2014 and 2015.⁷⁷

U.S. Utility-Scale Solar Photovoltaic Power Purchase Agreement Prices Over Time by Vintage⁷⁸



There is scope for renewables prices to drop even further. While prices have started to decrease by a smaller amount, they will most likely not stop once they beat natural gas prices because of the high competitiveness of the renewables; several recent RFPs issued by utilities in other parts of the county seeking renewable energy PPAs were solicited with 13 to 26 times the level of capacity required.⁷⁹ A number of potential developments could help drive renewable energy prices down, including continued technical improvements in renewables technology, the incorporation of cost-effective energy storage, and the shift towards a smarter grid that can enable distributed generation.

The Problem with Power Purchase Agreements

Long-term PPAs can be beneficial to various stakeholders due to their ability to decrease price uncertainty for renewables' electricity output. They accomplish this by serving as an "efficient substitute to vertical integration", facilitating producers' investment in renewable energy assets by hedging price and quantity risks.⁸⁰ Without this type of contract, it is safer to invest in lower capital cost assets such as combined cycle gas turbines that are self-hedged due to the close

relationship between electricity and gas prices observed in New England.⁸¹ Indeed, renewable energy projects are usually not considered financeable without a PPA, so these contracts are key to building out this new market.

The increased quantity of long-term PPAs has a number of negative impacts, however. They risk creating barriers to entry for future renewable energy players; if a significant amount of the electricity demand is tied up into the future, it could discourage more efficient producers from entering the market.⁸² These long-term contracts may also create barriers to entry “through explicit inclusion of restrictive conditions or by creating dominant positions”, which can deter market entry.⁸³ They can also dull price competition in the market, because the ability for new entrants to undercut prices is therefore limited.⁸⁴ Finally, if long-term contracts come at the expense of shorter-term contracts, there is the risk of detracting from the vibrancy of New England’s spot market because “spot markets deliver better results than bilateral contracting only if sufficiently liquid.”⁸⁵ A liquid and competitive spot market for electricity, as with any well functioning market, creates more transparency into supply, demand, and prices, in a way that long-term contracts cannot.⁸⁶ The spot market also provides a viable alternative to long-term contracts for smaller players, protecting them from larger and stronger entities.⁸⁷

Even more problematic than the increasing quantity of PPAs is their decreasing prices. While these past and potential price decreases may be encouraging to proponents of renewable energy, their linkage to long-term contracts can cause difficulties. As offtakers consider their energy procurement strategy, they perform an analysis of alternatives that includes energy sources of both today and tomorrow; renewable PPAs must compete not only with the prices of natural gas and coal, but against the perception that their own prices will drop in the future and that it might be worth waiting. For example, some customers may decide not to enter into solar PV PPAs this year because they expect that the price will be

significantly lower the following year; instead, they may expect to be better off by accepting a higher spot price for one more year in order to obtain the lower long-term contract price later. In this way, project developers relying on PPAs may in fact be limiting their market, hampered by their own success.

Those offtakers who have already signed PPAs are unfortunately held to a price for the ensuing decades in a context of falling prices. Utilities that are straddled with these stranded costs must nonetheless compete against those who are not yet locked in to energy prices.⁸⁸ For example, if a New England utility with a cost of capital of 3.3% signed a 20-year wind PPA at \$80 per MWh in 2010, it would have a net present value stranded cost of \$314 for each MWh contracted, compared to another utility that waited and signed a \$55 per MWh PPA in 2012. Before the market was deregulated, this additional cost would have been passed on to the ratepayers, but now this kind of structural cost weighs on utilities, rendering them less competitive and less flexible. As laid out in the chart to the right, the wind energy PPAs signed at these prices in 2010 left offtakers across New England with stranded costs with a net present value of \$138 million in 2012. This figure only includes wind PPAs for the one year; the overall amount of stranded costs in New England will only get bigger over time as the quantity of all types of renewable energy PPAs increases and the prices decrease.

The Stranded Costs of 2010 Wind PPAs in 2012	
2010 20-Year PPA Price (per MWh)	\$80
2012 20-Year PPA Price (per MWh)	\$55
Cost of Capital ⁸⁹	3.3%
NPV Stranded Cost (per MWh)	\$314
2010 New Wind Capacity (MW)	208
Capacity Factor ⁹⁰	24%
New Wind Generation (MWh)	437K
NPV Total Stranded Costs	\$138M

Over the next five years, as renewables continue to proliferate and PPA prices continue to drop, these long-term contracts will continue to lock in above-market costs. If the additional capacity for 1,700 to 1,900 GWh of renewable generation

is built annually to meet New England's RPS goals and PPA prices continue to drop by approximately 22% per year, in 2020 alone offtakers will be paying \$43 million more for their existing renewable generation than they would from new renewable assets.⁹¹ Moreover, these PPAs are long-term contracts that can last for over 20 years, locking in these stranded costs for decades into the future; just looking at the contracts that will be signed over the next five years, and even assuming that the price stops decreasing after 2020, New England offtakers with a 3.3% cost of capital will be committing to stranded costs with a present value of \$595 million.⁹² Even if PPA prices begin to decrease by only 11% annually, half of the current rate, the present value of the stranded costs would be \$368 million.⁹³ While long-term contracts can make sense for both buyers and sellers in circumstances of volatile prices that can go either up or down, the benefit may be less evenly split when prices are only expected to go down.

Offtakers may end up facing criticism for "jumping the gun" and signing too many PPAs at too high a price. Unfortunately for them, the contracts' termination clauses are generally strong; typically, offtakers who terminate PPA early are required to pay all of the expected costs.⁹⁴ That said, the impact of the broader energy transition on various offtakers' creditworthiness and ability to pay is unknown. Perhaps locking into these long-term contracts in this period of change will lead to unintentional contract renegotiations that are also unfavorable for the power producer. Increased credit risk on the part of the offtaker is the last thing power producers want, because their assets are usually project-financed with mostly debt, leaving little room for error.

How can these issues be addressed? Fortunately, this is not the first time the industry has been challenged by the proliferation of long-term contracts and the specter of decreasing prices; there are parallels to similar challenges faced during the deregulation of the electric power sector in the 1990s which may inform strategies to deal with the current issue.

Case Study

Public Utility Regulatory Policy Act Independent Power Producer Power Purchase Agreements

Paul Joskow, a renowned scholar of the electric power system, notes that “when the history of the later twentieth century electric power industry is written, the Public Utility Regulatory Policy Act of 1978 will be viewed as having profound effects on both the structure of the industry and the way it is regulated.”⁹⁵ Although Congress passed PURPA in an attempt to promote the use of cogeneration and renewable energy technology, PURPA’s biggest impact was opening the door to non-utility generators.

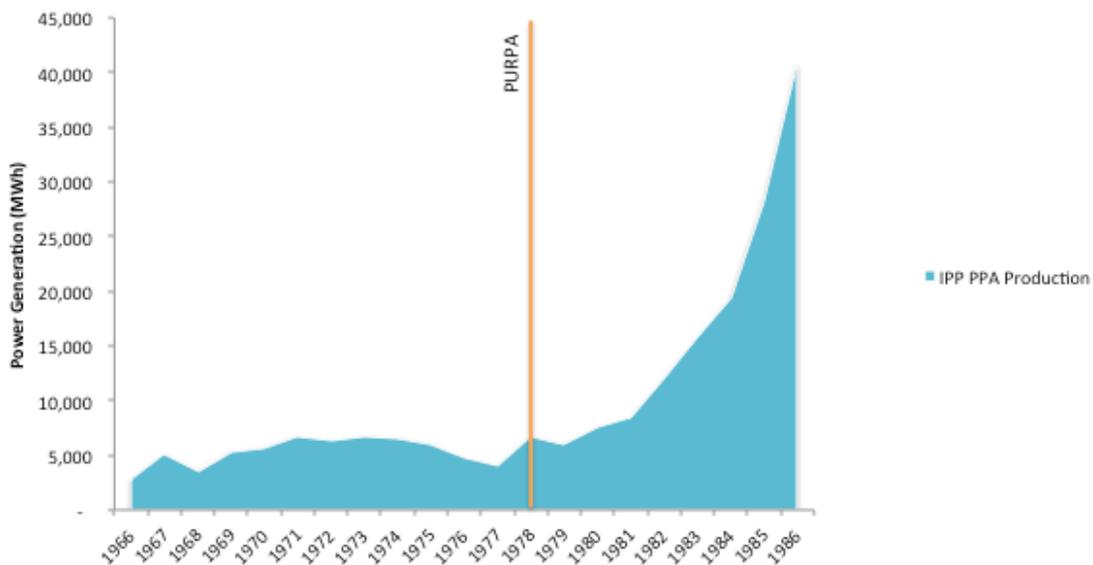
PURPA required utilities to purchase power generated by “qualifying facilities” at or below the “avoided cost” for the utility to produce electricity with similar characteristics. These avoided costs were often projected to be as high as 5 to 9 cents per kilowatt hour (kWh), which was more than enough to compensate many IPPs: in the 1980s, natural gas turbines typically cost \$600 to \$900 per kilowatt (kW) to build and the fuel cost 2.5 to 3 cents per kWh, so IPPs were able and happy to take advantage of the market opportunity created by this policy.⁹⁶ In fact, the average solicitation for independent capacity in 1990 was almost 17 times over-subscribed, often receiving bids from over 40 potential IPPs.⁹⁷

Utilities, too, were content with this arrangement. Due to increases in fuel costs and interest rates, the cost for them to build their own generation capacity was increasing significantly. Regulatory authorities, however, were loath to increase retail electricity rates based on these increased costs, squeezing the utilities’ margins and decreasing the return on investment for new generation capacity.⁹⁸ As a result, the utilities were readily willing to comply with the new federal and state regulations that allowed them to procure their electricity externally and pass

the costs through to their customers. Fundamentally, if the utilities took risks, any cost would be born by them and any benefit would be passed on to the consumer, but now they had the opportunity to outsource the risk associated with generation.⁹⁹

These incentives led to a dramatic growth in the amount of electricity generated by IPPs with PPAs, especially in regions with high cost utilities, such as New England.¹⁰⁰ As illustrated in the chart below, the amount of power generated by IPPs under PPAs with utilities increased eightfold in less than a decade after PURPA was enacted in 1978.¹⁰¹ By 1991, the year before the Energy Policy Act allowed FERC to official open the transmission networks to wholesale suppliers, 32 GW of non-utility capacity had been developed under PURPA, representing 4.3% of all the electricity generated in the United States. By 1995, these non-utility generators produced 7% of all electricity on the grid.¹⁰²

U.S. Power Generated Under PURPA IPP PPAs¹⁰³



The Problem with Public Utility Regulatory Policy Act Independent Power Producer Power Purchase Agreements

These long-term contracts became problematic as the industry shifted to competitive markets in the 1990's. Many of the contracts' prices had been determined by avoided-cost estimates that were much too high, based on aggressive predictions of high fuel costs and inflation rates. After a tumultuous 1970s and 1980s, analysts were forecasting oil prices of over \$100 per barrel and natural gas at \$9 per million British Thermal Units.¹⁰⁴ With these high contracted prices for electricity locked in and expectations that the new competitive markets would drive wholesale prices down, utilities were rightly concerned because any contract price over the market price would become a stranded cost on their balance sheets.

By 1997, the 114 IOUs in the United States were faced with \$122 billion in net stranded costs.¹⁰⁵ There were three categories of stranded costs: regulatory assets, generating plants, and long-term contracts above market cost. PPAs alone accounted for \$54 billion in costs that utilities were unsure they would be able to recover.¹⁰⁶ In fact, the average price of the IPPs' contracted power was 70% higher than that generated by the utilities themselves at the time.¹⁰⁷ Further, these high rates were locked in for a long period of time; of the contracts for at least 200 GWh a year, only 29 percent had expired by 2010.¹⁰⁸

These stranded costs were not spread equally amongst all IOUs. Two thirds of these assets were contracted to just 10 utilities, and a quarter were held by the top two alone: Pacific Gas & Electric and Southern California Edison¹⁰⁹. The former procured 49% of its power from IPPs, while the latter contracted 62%, giving it the highest wholesale power cost in the country, at \$76 per MWh versus \$27 to \$35 per MWh at wholesale market rates.¹¹⁰

As would be expected, these stranded costs directly impacted valuations of IOUs; share prices of the most affected IOUs in California, Pennsylvania, and New England experienced significant decreases in their share prices in the mid-1990s.¹¹¹ In fact, while the market-to-book value ratios for IOUs with and without stranded costs were similar in the regulated market (1970 to 1990), they became statistically different in the post-regulatory period (1993 to 1997): 1.5 for firms with stranded costs versus 1.8 for those without, suggesting that the market perceived the latter to have a meaningful competitive advantage.¹¹² Interestingly, stranded assets resulting from long-term contract commitments were viewed less negatively by investors than those from voluntary operating or investing decisions made by IOUs, as these were considered to have a higher probability of recovery because regulatory authorities had mandated them.¹¹³ As a whole, these stranded costs were considered quite detrimental to the IOUs, with investors anticipating that on average 10% of the costs would have to be borne by shareholders.¹¹⁴

Whether or not IOUs should be compensated for their stranded costs was a contentious issue. Utilities with high levels of stranded costs argued that regulations stemming from PURPA had caused them to enter into the long-term contracts, and that they should be remunerated based on the “regulatory compact” under which they had been operating when they signed the PPAs. Opponents, including IOUs with lower levels of stranded costs that wanted to maintain their competitive advantage, countered this reasoning, contending that such compensation “would subsidize certain high-cost generators to the detriment of competition”.¹¹⁵ The excerpted table below provides an overview of the arguments for and against stranded cost recovery.

Stranded Cost Recovery Debate Arguments (Excerpt)¹¹⁶

Supporting Arguments	Opposing Arguments
<i>“Under the ‘regulatory compact’, legislators and regulators entered into an agreement with utilities that granted certain rights and responsibilities to the utilities. The compact gives the utilities the right for full stranded cost recovery.”</i>	<i>“While regulators might have acted as a surrogate for consumers, few (if any) consumers actually signed and agreed to the ‘regulatory compact’. Full stranded cost recovery slows market entry and denies consumers the immediate benefit of competition.”</i>
<i>“Deregulation without compensation represents a ‘taking’ of property that is restricted under the Taking Clause of Fifth Amendment of the US Constitution.”</i>	<i>“The Taking Clause provides no constitutional guarantee that a regulated industry will never subject to deregulation, market reform, and competition.”</i>
<i>“Unanticipated breaching of the regulatory compact financially harms utility investors and can discourage future investments in the power sector.”</i>	<i>“Deregulation has occurred in other sectors (e.g., transportation, banking, and telecom). Rational investors should have anticipated the forthcoming power market reform. Moreover, post-reform investment continues in other sectors, and there is no reason to believe that investment would stop in the post-reform electricity sector.”</i>
<i>“Financially weak post-reform power companies can cause deterioration of service reliability and quality to the detriment of consumers.”</i>	<i>“Stranded cost recovery protects the financially weak post-reform power companies, frustrates market entry and competition, and perpetuates the inefficiency in the electricity sector.”</i>

As for the impact on regulatory authorities and ratepayers, it rapidly became evident that the discussion over stranded costs was a zero-sum game: either the IOUs’ shareholders would have to accept them, or the ratepayers would. The IOUs had been signing expensive long-term contracts based on the current regulation under which their costs would be covered and, even in the presence of competitive markets, would still fall on the ratepayers.

Independent Power Producer Power Purchase Agreement Integration Strategies

The IPP PPAs had to be integrated into wholesale markets. If not, the scope for competition would be decreased, new entrants would be deterred, and the system would be less efficient if power plants were dispatched out of merit order. In order to do so, integration required modification of some or all of the following: “market rules, IPP contract terms, identity and powers of the contract holder, contract management arrangements, and mechanisms for funding above-market costs associated with the IPP contracts.”¹¹⁷

It was clear that someone had to pay the stranded costs, be it the IPPs’ shareholders, the offtakers’ shareholders, the ratepayers, or the taxpayers. As such, the industry in the United States and abroad worked to devise strategies to integrate the PPAs in ways that minimized above-market costs while increasing market efficiency, liquidity, and competitiveness.¹¹⁸ These strategies included attempting to break PPAs, buying them out, voluntarily renegotiating them, aggregating them, or accepting them with a recovery policy.

Attempting to Break Power Purchase Agreements

As offtakers came to grips with the scale of their stranded costs, their first reaction was often to try to decrease the price of or to break their PPA contracts, leaving the losses with the IPPs’ shareholders. The former strategy rarely worked, as the generation assets were typically project financed with over 80% debt to service, rendering them inflexible to price changes. A few accepted decreased tariffs, however, as a preferable alternative to their offtakers potentially going bankrupt.¹¹⁹ The latter approach also rarely worked, as regulatory authorities and federal courts usually upheld the original contracts, causing the parties to be required to honor their commitments for the life of the

PPAs.¹²⁰ This strategy would not have been optimal anyway, as above-market costs were not reduced, rendering the utilities less competitive and eventually saddling ratepayers with higher prices. Further, allowing offtakers to breach contracts en masse would have hurt the credibility of the government and greatly deterred investors in the future.

Buying out Power Purchase Agreements

Some offtakers worked with IPPs to buy out their contracts, a strategy that decreases uncertainty for both parties. One example is provided by Niagara Mohawk Power Company, which announced in March 1997 that it had bought out 44 PPA contracts from 19 IPPs, representing 90% of its stranded costs. The present value of the contracts was \$9 billion, which the utility purchased in exchange for \$3.6 billion in cash and 46 million share of its stock, a move that was estimated to have saved the company \$5 billion over 15 years.¹²¹ Pennsylvania Power and Light employed a comparable strategy a year earlier, paying \$91 million to terminate a 100 MW PPA.¹²²

Third parties can also employ this strategy, as when Citizen Power restructured a PPA between Central Maine Power and Maine Energy Recovery Corporation. Citizen Power financed the \$80 million contract buy out while transferring some risk to the utility to minimize the cost of capital, decreasing the amount of power purchased at above-market rates, extending the contract by five years, and splitting the price into energy and capacity components, resulting in a saving of \$24 million.¹²³ As demonstrated in these examples, these types of negotiations can benefit all parties. It also has the advantage of “crystalizing” stranded costs sooner rather than later, allowing offtakers to write off a concrete loss instead of letting the uncertainties cloud their performance.

Renegotiating Power Purchase Agreements

Parties to PPAs could also often obtain mutual gains from voluntarily renegotiating their contracts; similar to the Citizen Power example above, contractual terms could be traded off to both the IPPs' and the offtakers' benefit. These included reducing the PPA length or gradually introducing market risk later in the contract term and allowing generators to sell capacity that had not been contracted or to bid into the markets for ancillary services such as frequency and voltage control.¹²⁴ Sometimes these renegotiations were held *ad hoc*, while in other cases they were part of a clear offtaker or government strategy. In California, for example, offtakers had a "firm but fair" policy in which they would attempt to restructure the financial terms of the PPA whenever the IPP requested any contract changes.¹²⁵ The governments of Ontario, Canada, and Thailand had even more systematized contract renegotiation facilitation processes, with managers appointed to find mutually beneficial opportunities to renegotiate PPAs, and who were financially incentivized with a cut of the stranded costs that were avoided.¹²⁶ Under any of these approaches, the benefits from the renegotiated terms could be shared among the parties to reduce stranded costs associated with the PPAs.

Aggregating Power Purchase Agreements

Another approach was to aggregate the management of PPAs from different offtakers. While the individual offtakers still held the contracts, designated contract managers tended to the day-to-day administration of portfolios of PPAs with the main goal of minimizing stranded costs. This arrangement had the benefit of empowering a focused agent, with expertise and a portfolio of assets, to bid contracted generation capacity into the wholesale market, all while preserving the IPPs' contractual rights.¹²⁷ This approach was successful in Victoria, Australia, for example, where existing PPAs were allocated to one of

four “PPA Traders” who did their best to bid the electricity at the lowest loss, which was then eventually passed on to ratepayers.¹²⁸ This integration strategy was innovative in that it optimized the reduction in stranded costs, though it still required consumers to accept those that remained.

Maintaining Power Purchase Agreements, with Stranded Cost Recovery

Finally, many offtakers also pushed for regulatory reform or stranded cost recovery. As mentioned earlier, regulatory authorities determined that IPPs’ shareholders should not be liable for the stranded costs, based on their defensible contracts. Most also decided that offtakers’ shareholders should not be left with the bill, because utilities were acting as mandated by PURPA in signing PPAs with the IPPs. Taxpayers, as well, were not to be charged, because using public funds would be politically difficult and could “provoke criticism.”¹²⁹ Instead, regulatory authorities determined that ratepayers should cover the costs because they were the intended benefactors of the reforms, there was already a billing mechanism in place, and, in any case, they would have had to pay the same costs in the absence of the regulatory change.

FERC’s Order 888, issued in 1996, allowed the recovery of stranded costs from ratepayers and was supported by legislation at the state level.^{130 131} Cost recovery by utilities as a “transition charge” on ratepayers’ bills was implemented in several ways, such as a “headroom charge” in California, a surcharge on energy transmitted in Massachusetts, or a surcharge on current composition or load¹³². Regardless of the cost recovery mechanism, this strategy led to higher retail electricity prices that ratepayers were forced to pay. Similar to the contract breach strategy, this approach does not minimize stranded costs and does not contribute to a more competitive or efficient market.

Discussion

The integration of PURPA IPP PPAs into U.S. wholesale markets is several decades removed from the issue of renewable energy PPAs in New England. So, how applicable is the former as a case study to the latter? While there are some differences, there are many key similarities that recommend PURPA IPP PPAs as a useful source of lessons learned for the current situation.

Similarities and Differences

The main similarity is the significant increase in long-term PPAs for a certain generation class, whether they be PURPA IPPs or renewable energy assets. These increasing trends were a result of regulatory changes for both the IPPs and the renewable energy assets; the implementation of PURPA in the case of the former, and the passage of policies such as RPS and tax credits in the case of the latter. Both cases have similar impacts on stakeholders in terms of stranded costs and decreasing liquidity, transparency, and competitiveness in the market. Finally, both came at, and were linked to, times of heightened uncertainty for offtakers. Utilities were dealing with PURPA IPPs when they were on the cusp of deregulation and the wholesale market, and they will now be grappling with renewable energy PPAs during the transition to distributed generation and attempting to becoming the “utility of the future.”

A key difference, however, is that the integration of PPAs into the wholesale market in the earlier case was mandated, while the reconciliation of renewable energy contracts today is not. Offtakers were forced to confront the stranded costs they had locked in through PURPA IPP PPAs when regulatory authorities started the process of integrating the utilities into wholesale markets. They had to determine whether they would be required to accept these costs themselves, or if they could push them onto someone else. Today, there is no such catalyst.

Utilities will not be faced with a pressing decision about how to address the issue of renewable energy PPAs, but will instead be faced with a creeping calcification of their cost structures. The incremental nature of today's problem could make it harder to garner political support to address it. This may present an opportunity for strategic players to employ some of the approaches discussed in this report. Another difference is that while utilities were directly forced to enter into PURPA IPP PPAs, they are only indirectly being caused to enter into renewable energy PPAs by RPS targets. As such, the utilities may have greater difficulty blaming the law this time for entering into PPAs today that may be considered ill advised in the future.

Lessons Learned

Based on the parallels between the PURPA IPP PPA case study and the current renewable energy PPA issue, there are several lessons that can be extracted. First, any resolution to the current issue will involve adjusting market rules, changing contract terms or management, altering powers of contract holders, or employing stranded-cost funding mechanisms. Second, the goal of any solution should be to minimize stranded costs and increase market liquidity and competitiveness, without compromising system reliability or efficiency. Finally, the case study reinforces that someone will have to pay to resolve this issue: the shareholders of the IPPs, the shareholders of the offtakers, the ratepayers, or the taxpayers. It is thus in these stakeholders' interest to actively search for a resolution that is to their advantage, and in society's best interest to find a solution that meets the goals outlined above.

Some of the strategies employed in the case study are more feasible today than others:

- The first strategy, breaking today's renewable energy PPAs, is unlikely to be successful because of the contracts' rigorous termination clauses, which courts will most likely uphold.
- The second, buying out the PPAs could be a good option, though it would probably be difficult for utilities to get buy-in from their shareholders to execute this approach. While it could be beneficial to crystalize and write off these stranded costs earlier, no utility would want to be the first to voluntarily accept these expenses, in the absence of some external stimulus. There could potentially be room for third parties to add value, however, as in the Citizen Power example.
- The third, renegotiating contracts to make them more flexible, and negotiating new PPAs this way as well, could potentially be the biggest boon for both producers and offtakers, provided the contracts are still bankable.
- The fourth, aggregating PPAs into independently managed portfolios could be an effective approach to minimize stranded costs, and could be an opportunity for entrepreneurial third parties.
- Finally, using a formal recovery mechanism to pass on the stranded costs to a third party is unlikely because, as mentioned above, there is no impetus for anyone but the offtaker to accept these costs.

Conclusion

The problems associated with the proliferation of renewable energy PPAs and continually declining prices have implications for offtakers, power producers, and regulatory authorities.

Offtakers

The stranded costs that utilities accumulate as they sign long-term PPAs for renewable energy generation risks slowly crippling them. In the short term, utilities will continue to pass these costs along to their ratepayers on their bills. This should not be too problematic at first, because demand for electricity is generally inelastic and often not a major concern for most customers. Furthermore, the declining renewable energy prices should in fact bring the weighted average of the utilities' costs down. Eventually, however, these long-term contracts may begin to hurt utilities' competitive position *vis-a-vis* players with less baggage, including competitive electricity retailers without above-market PPAs and solar installers, that could offer lower rates to the utilities' customers. In the longer term, the fixed costs associated with these PPAs could prove to be insurmountable if utilities find themselves in financial trouble; if an offtaker is struggling to transform into the "utility of the future", these contracted costs, like excessive leverage, could conceivably be the *coup de grace* that eventually pushes a company into bankruptcy.

As policy makers are not actively addressing this problem, offtakers must act either to minimize the number of PPAs they sign or to mitigate their negative consequences. Utilities could decide to avoid entering into these long-term agreements until renewable energy prices have stabilized, and just purchase the requisite RECs in the market to meet their RPS targets. This approach would minimize their exposure to stranded cost risks, but would also prevent them from

building the renewable energy knowledge and experience required to be a meaningful participant in any energy transition. Utilities could also begin reducing the length of new PPAs. Duke Energy, for example, now rarely enters PPAs for longer than 15 years, though this requirement could make it harder to procure as much renewable energy as needed.¹³³ Utilities should also strive to minimize the risk associated with their existing and new PPAs. Strategies to pursue mutual gain between offtakers and producers include those discussed above, such as contract buyouts or voluntary renegotiations to increase the flexibility of contracts. Utilities might also examine the possibility of employing certain hedge products to control for price declines, though these are often difficult for electricity.¹³⁴

Power Producers

Unless utilities decide to decrease the number or shorten the duration of PPAs they sign, renewable energy power producers have little to fear in the short term from the stranded costs they are creating. As described above, the existing and new contracts power producers are banking on will most likely be upheld in court. Eventually, however, they may have to start worrying about the creditworthiness of their utility offtakers, which is a major concern for owners of debt-heavy project financed assets.

As with the offtakers, power producers could potentially find opportunities for mutual gain by considering buyouts or renegotiations of their current contracts. A potentially bigger opportunity would be to develop innovative new PPA structures that minimize the tensions identified in this report. For example, as renewable energy costs become more competitive with those of natural gas, instead of continuing to decrease PPA prices, power producers could shorten PPA durations or increase their exposure to market prices later in the contract term. Flexible contracts could serve as both a competitive differentiator, which could allow them to charge a premium, and as a means of decreasing their offtakers'

credit risk, which could decrease producers' cost of capital. Another approach for power producers to minimize their long-term credit risk from utilities could be to diversify offtakers to a larger number of smaller customers. This could include employing Virtual PPAs to increase exposure to commercial and industrial (C&I) customers, or using the "community solar" model to apportion utility-scale renewable projects amongst a large number of residential customers. These C&I and residential customers, for whom electricity is just a fraction of their expenses, are less likely to build up as significant amounts of stranded cost liabilities as utilities and therefore would be less risky as offtakers.

Policy Makers

State policy makers will have to decide whether to intervene in this situation and, if so, how. They could let the market dynamics play out, but this could result in negative consequences for utilities, and therefore negatively impact the reliability of the electric power system. Furthermore, these stranded costs will be included in the rates that customers are paying, which is one of policy makers' biggest concerns. Alternatively, the government could take steps to minimize the negative consequences of PPAs, such as establishing voluntary contract renegotiation mechanisms or incrementally adjusting subsidies and regulations to keep PPA prices steady once the prices reach grid parity. Policy makers could also consider regulating the length of PPAs that are allowed, gradually decreasing the duration of new contracts to push the industry to find solutions to minimize stranded costs. A more aggressive intervention could eventually include passing stranded costs on to taxpayers. Whereas transition charges were passed on to ratepayers after deregulation, because wholesale markets were thought to be to their benefit, the transition to renewable energy could be considered a benefit of society as a whole.

Policy makers must prepare for a debate about renewable energy PPAs that is at least as contentious as the debate over integration of PURPA IPP PPAs into wholesale markets. Instead of merely acting as referees among stakeholders, New England policy makers must consider the broader interests of the region and then work with the stakeholders to achieve them. For this reason, policy makers need to consider this issue now, rather than waiting for the debate to begin and stakeholder positions to solidify. As New England transitions to the electric power system of the future, policy makers must lead the way while balancing the needs of diverse and powerful stakeholders.

Appendix

Stranded Cost Calculation

	2016E	2017E	2018E	2019E	2020E	
Total Prod. (MWh) [i]	108,516,686	109,276,303	110,041,237	110,811,526	111,587,207	
% Renewable [ii]	11%	12%	14%	15%	17%	
Renewable Prod. (MWh)	11,503,437	13,319,073	15,159,564	17,025,169	18,916,150	
Adttl. Ren. Prod. (MWh)	1,791,037	1,815,636	1,840,491	1,865,605	1,890,981	
W.A. PPA Price [iii]	\$ 25.73	\$ 20.03	\$ 15.60	\$ 12.14	\$ 9.45	
Stranded Cost (per MWh)	\$ 7.32	\$ 5.70	\$ 4.44	\$ 3.45	\$ 2.69	
Stranded Costs						Cum. Stranded Costs
2016	\$ 13,113,467					\$ 13,113,467
2017	\$ 13,113,467	\$ 10,349,165				\$ 23,462,632
2018	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214			\$ 31,629,847
2019	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011		\$ 38,074,858
2020	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2021	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2022	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2023	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2024	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2025	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2026	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2027	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2028	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2029	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2030	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2031	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2032	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2033	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2034	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2035	\$ 13,113,467	\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 43,160,605
2036		\$ 10,349,165	\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 30,047,138
2037			\$ 8,167,214	\$ 6,445,011	\$ 5,085,747	\$ 19,697,972
2038				\$ 6,445,011	\$ 5,085,747	\$ 11,530,758
2039					\$ 5,085,747	\$ 5,085,747
						Disc. Rate [iv] 3.3%
						Present Value \$ 594,828,573

Notes:

- [i] Estimated total electricity production in New England based on historical ISO-NE data, growing at 7% annually based on a Kinder Morgan estimate.^{135 136}
- [ii] Estimated percent of total electricity production from renewable sources based on straight line growth of 1.6 percentage points to meet the region's weighted average 17% RPS requirement.¹³⁷
- [iii] Estimated PPA price is a weighted average of current wind and solar prices, decreasing at the weighted average of the two technologies' prices' negative Compound Annual Growth Rate (CAGR) between 2010 and 2015 of -22%.¹³⁸
- [iv] Discount rate based on the Weighted Average Cost of Capital (WACC) of Eversource, a large regional IOU.¹³⁹

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