Policies to Cost-Effectively Retain Existing Renewables in New York

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EXECUTIVE SUMMARY

New York will rely on a diverse array of renewable generators to meet its ambitious Renewable Energy Standard (RES) target of 50 percent renewable electricity by 2030. Meeting the 2030 target will require an "all hands on deck" effort. New York is not starting from scratch on its way to 50 percent: It is starting from a 29 percent renewable baseline (Baseline) established based on renewable energy used in New York in 2014.[1] The Baseline includes the output from hydroelectric facilities owned and operated by the New York Power Authority (NYPA), imported hydropower, and the output from independently owned facilities that served New York load in 2014. In developing the RES, New York policymakers assumed that the Baseline resources would continue to serve New York, so that the policy could focus on developing new resources.

The Alliance for Clean Energy New York (ACE NY) commissioned Synapse Energy Economics (Synapse) to analyze the impact of the policy status quo on New York's progress toward its 2030 goals and the relative cost and benefits of other policy options. Synapse is a research and consulting firm specializing in energy, economic, and environmental topics.

This report is concerned with threats to New York's Baseline assumption resulting from the risk of export or retirement of independent Baseline resources that began operation before January 1, 2015. In total, these independent resources contributed 10 TWh in 2014, or just short of one quarter of the Baseline.

To meet its 2030 target, New York entities will need to retain ownership of the renewable energy credits (REC) corresponding to 50 percent of 2030 load. If Baseline resources export their RECs to other jurisdictions or retire, New York will need to replace them with additional and likely more expensive new Tier 1 RECs. **This report analyzes policy options to retain RECs from existing resources and shows that they could save New York ratepayers between $135 and $377 million between 2019 and 2023 (present value).[2]**

If New York does not establish policies designed to retain RECs from existing independent generators, it will lose some of its Baseline and backslide below the 29 percent starting level. This will make meeting the 50 percent target both more difficult and more expensive than it would be if existing resources were retained.

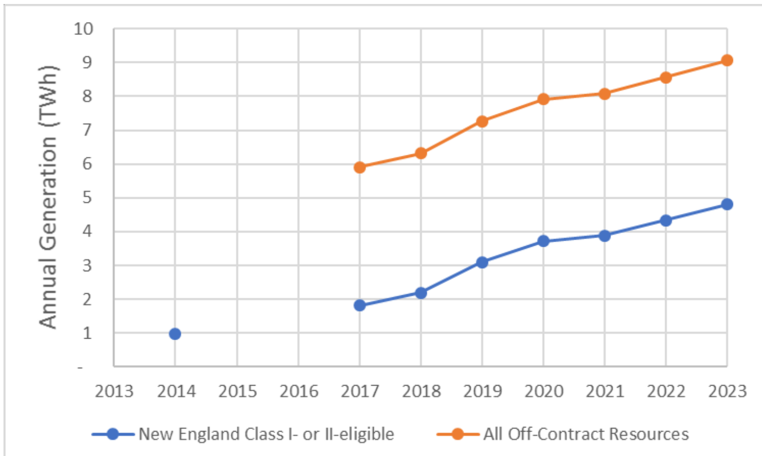
Backsliding would begin by 2019, when generators with expiring NYSERDA contracts, along with uncontracted older resources, find opportunities to export that exceed the amount of new Tier 1 resources coming online. Replacing just the 2.1 TWh of increased likely REC exports to New England in

[1] New York Public Service Commission. Order Establishing Clean Energy Standard. CASE 14-E-0302, issued August 1, 2016. The 29 percent value is relative to the expected 2030 load, after accounting for energy efficiency. The Baseline resources generated about 27 percent of 2014 load.

[2] Present values are calculated to 2018 with an 8% discount rate.

2019 with new wind generation would require more than 725 MW of new resources to come online, assuming a 33 percent capacity factor. Further erosion of the Baseline is possible from older resources selling RECs to voluntary or lower-value markets. While some new generation will come online by 2019, it will be adding to a retained Baseline of 27.5 percent or lower of 2030 load, rather than adding to the expected Baseline level of 29 percent of 2030 load.

Figure 1: The amount of independent existing New York generation that is not contracted in New York and eligible to export to New England or otherwise sell RECs outside of New York, 2017 to 2023. The 2014 data point is the actual REC exports to New England in that year.



If New York takes no policy action for existing renewable generators and instead acquires Tier 1 resources to make up for their loss, we estimate that the present value of ratepayer costs in the five years from 2019 to 2023 will be $706 million. Based on our projections of Tier 1 REC prices and the costs of the Maintenance Program, ratepayers will pay an average of $28/MWh for renewable attributes. Adopting the Department of Public Service (DPS) Staff proposal for the Maintenance Program[3] would increase the cost per MWh to over $29 because it would result in less Maintenance Program participation than the status quo and thus require the acquisition of additional Tier 1 RECs.

The Public Service Commission (PSC) could take several varying approaches to keeping New York's independent renewable generators operating in and serving New York. We developed and modeled five alternative policies that either reduce ratepayer costs or attract existing renewable resources in addition to the Baseline, or both:

1. Tier 2 RECs purchased from all comers at 75 percent of the average Tier 1 REC price for each year;
2. Tier 2 RECs purchased from all comers at 100 percent of the average Tier 1 REC price for each year;

[3] New York Department of Public Service, "Staff Report Regarding Retention of Existing Baseline Resources Under Tier 2 of the Renewable Energy Standard Program," Case 15-E-0302, issued Oct. 19, 2017.

3. Tier 2 RECs purchased from all comers at the social cost of carbon emission avoided by those generators, adjusted for expected Regional Greenhouse Gas Initiative (RGGI) revenues;

4. Tier 2 RECs purchased from all comers at the social cost of carbon emission avoided by those generators, adjusted for expected RGGI revenues and for expected market energy prices; and

5. A rolling REC auction in which one third of the off-contract existing independent generation in the Baseline is acquired each year through competitive procurement.

All of these policy options start with an obligation for New York's load serving entities (LSEs) to purchase the Tier 2 RECs acquired through the policies. We have analyzed the period 2019 to 2023 to reflect that fact that program changes would likely not be fully implemented until 2019, and projections past 2023 are increasingly uncertain due to changes in market conditions and rules (including RPS rules in New York and other states as well as incorporation of carbon pricing into wholesale markets).

Table 1: Present value costs of each policy option from 2019–2023, along with per-MWh costs (not present-valued) of renewable energy New York can claim in each case. Parenthetical numbers in red are negative (savings from the Base Case).

Policy Option	Total Cost ($ millions)	Cost vs. Base Case ($ millions)	Avg. REC Cost ($/MWh)[4]	Avg. REC Cost vs. Base Case ($/MWh)
Base Case/Status Quo	657		28.04	
DPS Staff Proposal	684	27	29.17	1.12
1: 75% of Tier 1 Avg.	522	(135)	22.26	($5.79)
2: 100% of Tier 1 Avg.	760	103	29.12	1.08
3: Carbon Value	480	(177)	20.43	($7.61)
4: Market Responsive Carbon Value	462	(195)	19.60	($8.44)
5: Rolling REC Auction	280–429	(377)–(228)	$14.71–$22.25	($13.34)–($5.80)

Table 1 summarizes the results of our policy analysis. Four of the five options have lower ratepayer costs on both a total present-value basis and a per-MWh basis, with cost savings from $135 to $377 million in present value, or between $5.79/MWh and $13.34/MWh.

[4] Average REC costs are the costs for Tier 1 and Maintenance RECs in the Base Case/Status Quo and DPS Staff Proposal cases, and Tier 2 and Maintenance RECs in the five policy option cases.

1. BACKGROUND

New York has a Renewable Energy Standard (RES) target of 50 percent renewable electricity by 2030. To meet this goal, the state will need a broad combination of renewable generators that use a wide range of technologies and fuels such as solar, wind, hydroelectric, biomass, and landfill gas. This combination will include both new and older facilities, facilities inside and outside of New York, and generators owned by public authorities and independent power producers.[5] In short, meeting the 2030 target will require an "all hands on deck" effort.

New York starts more than halfway to the 50 percent renewable target. In fact, in establishing the RES, the Public Service Commission (PSC) incorporated a set of Baseline renewable resources amounting to 29 percent of projected 2030 load. The Baseline includes the output from hydroelectric facilities owned and operated by the New York Power Authority (NYPA), imported hydropower, and the output from independently owned facilities that served New York load in 2014. This leaves just 21 percent left to acquire between 2016 and 2030, provided the state can maintain its Baseline resources. This report is concerned with a subset of the resources that New York is counting on as part of the Baseline, but which the RES policy does little to retain in operation or serving the state. These are the independently owned facilities that began operation before January 1, 2015.

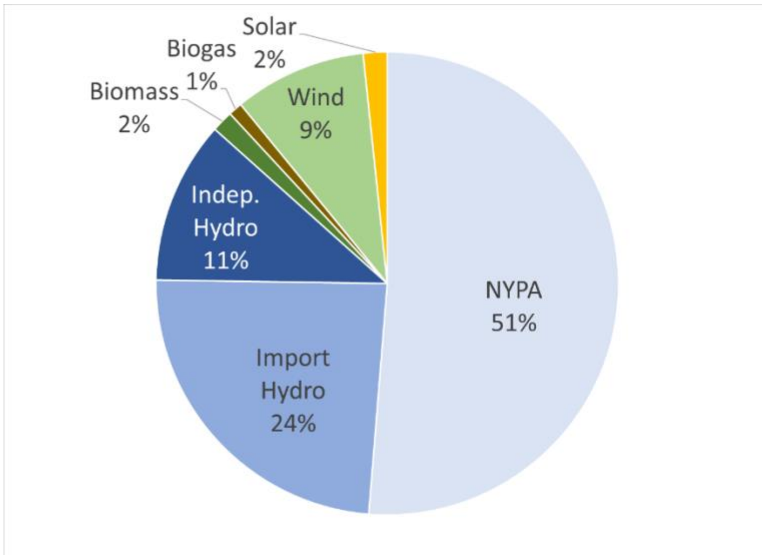
1.1. Clean Energy Standard: The Baseline

The Baseline resources that the PSC identified when establishing the RES cumulatively provided 41.3 TWh of electricity to meet New York load in 2014. More than half of this was provided by NYPA, predominantly from its Niagara and St. Lawrence projects. About another quarter was provided by hydroelectric projects outside the scope of this report: imports (such as from Quebec). The remainder were the contributions from the class of generators that are the focus of this report: independently owned and operated hydroelectric, biomass, biogas, wind, and solar facilities. In total, these independent facilities provided 10 TWh for the Baseline.

Throughout this report we will be concerned with the loss of Baseline. We hold NYPA generation and large hydro imports constant, so the Baseline retained or lost is a product solely of the disposition of the independent existing generators.

[5] There are also a small number of facilities reported to the U.S. Energy Information Administration as being owned by electric utilities; we have excluded these from our analyses of independently owned facilities.

Figure 2: Composition of the Baseline. This report is concerned with the upper left quadrant: independent in-state existing resources.



Pre-Existing Exports

New York generators in 2014 produced more than the 10 TWh of renewable resources credited to the Baseline, but New York has only claimed 10 TWh because the remainder was exported to New England and used for compliance with New England state renewable portfolio standards (RPS).

The 2014 renewable portfolio standard (RPS) compliance report in Massachusetts[6] indicates that more than 880 GWh of New York resources that would otherwise have been part of the Baseline were instead exported to New England. This includes 427 GWh of wind and 454 GWh of biogas. About 100 GWh of New York attributes were used for 2014 RPS compliance in Connecticut[7] and are thus also excluded from the Baseline. More than 3 percent of the target for new resources by 2030 could have been avoided by retaining these resources in New York, but the combination of policies and market forces that drove the export of clean energy attributes has led to a larger expected need for new Tier 1 resources.

Because New York had no generator attribute tracking system (GATS) until recently, there is no comprehensive accounting of the ownership and location of the renewable attributes claimed in the 2014 Baseline. New York has accounted for attributes that transferred to New England or other jurisdictions along with the associated power. However, there is no accounting for the unbundled sale of

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[6] Massachusetts Department of Energy Resources, "Massachusetts RPS & APS Annual Compliance Report for 2014." 2016.

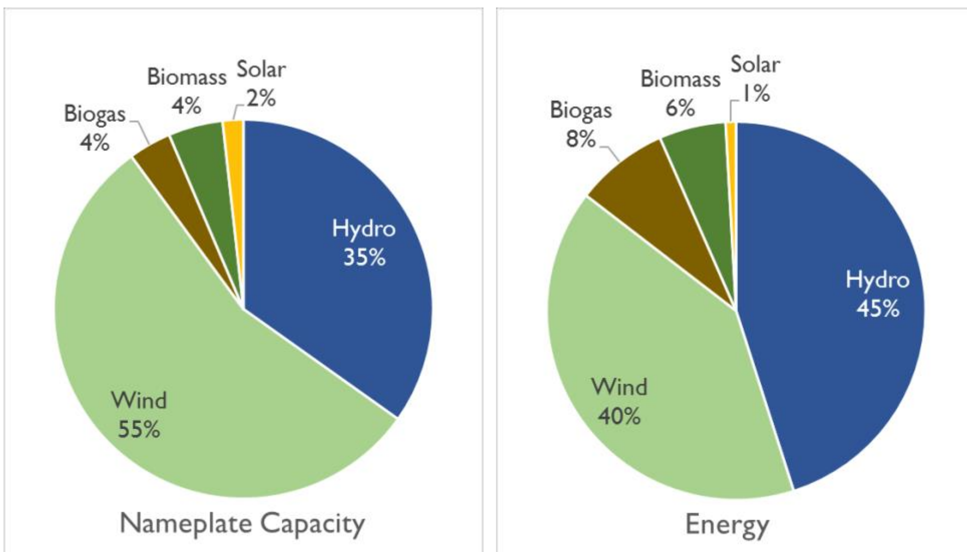
[7] Connecticut Public Utilities Regulatory Authority, Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in The Year 2014, Docket No. 15-09-18, issued Sept. 28, 2016.

renewable attributes in 2014. New York may therefore be counting in its baseline attributes which were sold to entities outside of the state, who have the right to exclusive claim on those attributes.

1.2. Diverse Independent Resources

Independent in-state renewable generators in operation before January 1, 2015 total 3,179 MW of capacity and generate 9.3 TWh of electricity annually.[8] We refer to these generators as "existing" generators because they predate the cutoff for eligibility for Tier 1 of the New York RES. While wind power makes up more than half of the capacity of the existing independent generator fleet, the higher capacity factor of hydroelectric generation means that hydro produces 45 percent of the energy, while wind generates 40 percent. Biogas, woody biomass, and solar together make up 10 percent of the capacity and generate 15 percent of the energy.

Figure 3: Composition of the independent existing generators in terms of capacity and the proportion of energy produced



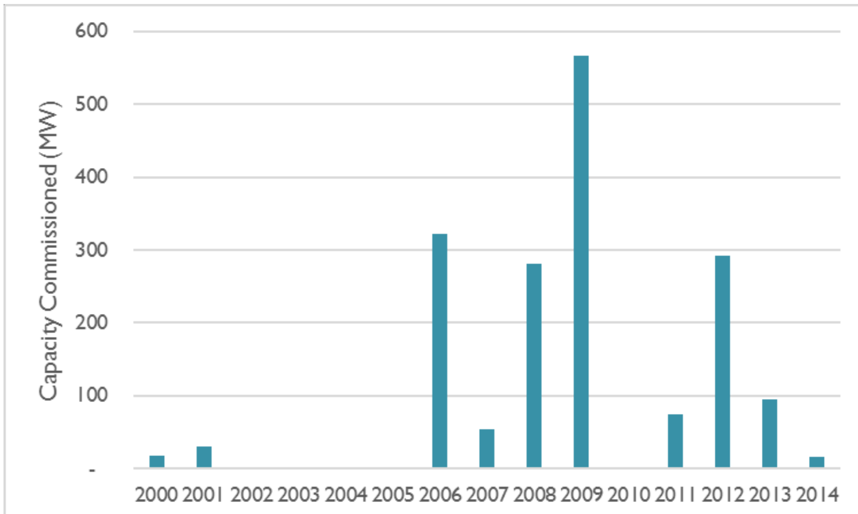
Wind

Existing independent wind generators are almost exclusively facilities that were developed under the previous form of the New York RPS. They typically have 10-year contracts to sell their renewable attributes to the New York State Energy Research and Development Authority (NYSERDA). Of the 1,751 MW of existing wind, 1,703 MW came online in 2006 or later. These 19 recently built facilities range in size from 20 to 322 MW. More than 20 percent of existing wind generator capacity (377 MW) has

[8] Five-year average energy production, 2012–2016. This number is less than the 10 TWh of independently owned resources included in the Baseline because the universe of generators we are considering does not include behind-the-meter solar (0.6 TWh/yr. difference) and 2014 biomass, wind, and hydroelectric production were noticeably above the five-year average (0.1 TWh difference for biomass, 0.2 TWh difference for wind, and 0.5 TWh difference for hydro).

passed the expiration of their NYSERDA contracts, and 849 MW more will pass 10 years of operation by the end of 2019. Together, the independent existing wind fleet generates about 3.7 TWh of electricity each year.

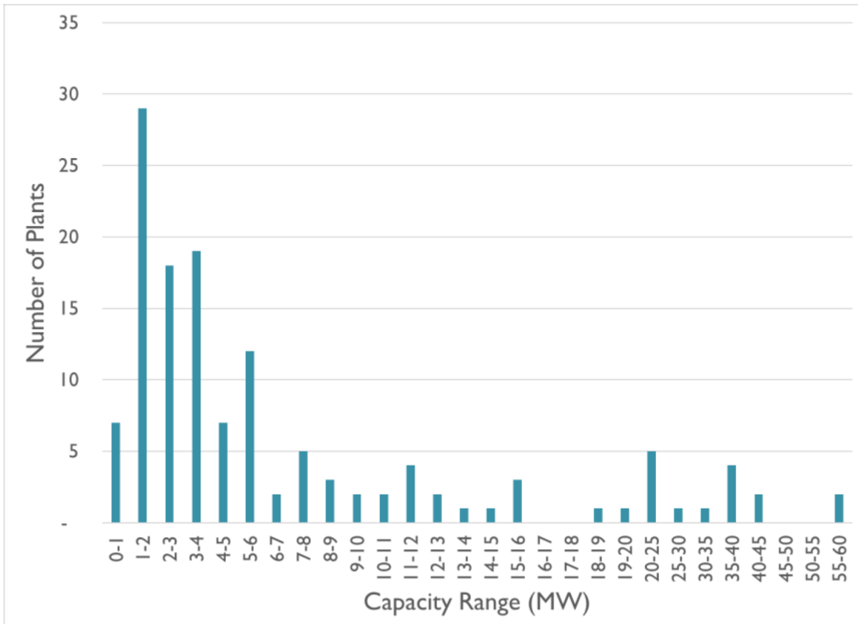
Figure 4: Existing wind generation capacity by year of commissioning



Hydro

In contrast to the relatively few, large, and young wind facilities, New York's existing independent hydroelectric fleet consists of many small and older facilities. We have identified 134 existing independent hydroelectric plants, ranging in size from less than 1 MW to 59 MW. The oldest entered service in 1908; the newest in 2012. More than three quarters of these plants are less than 10 MW in capacity. Together these small plants have a capacity of 378 MW and they generate about one third of the existing hydro energy. Taken together, the independent in-state existing hydroelectric fleet generates about 4.2 TWh of electricity each year.

Figure 5: Distribution of New York's existing independent hydroelectric generation fleet by capacity



2. Generator Options

Owners of existing generators are economic actors, and they respond to economic forces—in particular, to prices. When presented with a set of options for how to sell the output of their facilities, including their environmental attributes, they will select the options that offer the best combination of risk and reward. Given the robust wholesale energy and capacity markets in New York, New England, and PJM, there is little difference in risk between options for plants' energy and capacity. Therefore, the deciding factors for the sale of each plant's output will be prices for energy and capacity combined with state policy and programs.

Generator owners will do the economically rational thing:

- Keep energy and attributes in New York;
- Send energy and attributes to be used for RPS compliance elsewhere; or
- Sell energy in New York but sell attributes to serve the voluntary REC market elsewhere.

If none of these options allow for the prospect of a net positive income (after accounting for the costs of debt and equity for any necessary capital investment), the rational thing to do is to retire the facility.[9]

Our analysis aims to estimate what owners will do under the status quo or various policy scenarios. The remainder of this section summarizes the options available to different types and vintages of generators.

2.1. Export Options

New England Class I

The "new renewables" tiers of New England state RPS programs are generally referred to as "Class I." While eligibility requirements vary somewhat between states, the dominant markets in Massachusetts and Connecticut are largely compatible. New England Class I RECs have generally been among the highest value RECs in the country, with prices at times close to the alternative compliance payment levels of more than \$50/MWh (and sometimes over \$60/MWh in Massachusetts). Recent prices have been near \$15–\$25/MWh.[10] RECs are tracked in the NEPOOL Generator Information System and must be associated with energy delivered into ISO New England.

All New York-based wind, solar, and landfill gas generators are eligible for at least one Class I program in New England if they export their energy into the region. The lost Baseline from wind and landfill gas that New York experienced in 2014 was exported to these markets. Some recently upgraded hydroelectric generators are also eligible, and New York biomass electric generation could be eligible for Connecticut's Class I program if it meets that state's NO_X threshold of 0.075 lbs/MMBtu.

Slightly more than half of the generation from independent existing generators would be eligible for Class I treatment: 4.6 TWh per year. As discussed above, almost 1 TWh/year of generation from these sources was already exported in 2014 and is thus not in the Baseline. Additional possible exports are therefore 3.6 TWh per year. Many of these resources were developed under the Main Tier of the previous New York RPS, which placed them under 10-year contracts for 95 percent of their RECs. However, these REC contracts are ending. Class I exports of New York Baseline RECs could rise from 0.47 TWh in 2017 to 1.8 TWh in 2019, 2.5 TWh in 2021, and 3.5 TWh in 2023. See Figure 8 in Section 3.1 for the increase in eligible exports by year.

Existing resources associated with Class I resources in New England state procurements

New England states have run several single- or multiple-state procurement processes for Class I RECs in the last few years. Most recently, in March 2017 Massachusetts distribution utilities solicited 9.45

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[9] A facility operator may be able to cut costs that would otherwise enable long-term operation and continue to operate for some period; but when capital investment is required, retirement will be the rational choice.

[10] Indicative REC prices from Karbone, August 30, 2017.

TWh/year of Class I resources with firm delivery; existing hydroelectric resources can be used to firm that delivery and would also be eligible for Massachusetts's Clean Energy Standard.[11] One bidder proposes to use 70 New York hydroelectric plants (which have an annual output of 2.9 TWh per year) as the firming resource for new wind and solar located in New York, along with new transmission capacity to bring those resources to New England. If this bidder were to be successful in the Massachusetts procurement, these existing hydroelectric resources would be lost to New York past 2030. Even if this bidder is not successful this year, the existence of this procurement process (and its predecessors) suggests that there will be a continued risk that existing New York renewable resources will find a willing buyer offering a long-term contract in New England. These at-risk resources include both those that generate Class I-eligible attributes and those which can be part of an eligible suite with Class I-eligible resources.

Massachusetts Class II

Low-impact hydroelectric generators (as certified by the Low Impact Hydropower Institute (LIHI)) generate attributes that are eligible for Class II of the Massachusetts RPS. Massachusetts operates Class II so that it is in a state of permanent shortfall. This keeps the Class II REC prices at the level of the Alternative Compliance Payment for this Class, which was set at $25/MWh in 2009 and rises with inflation. Its level in 2017 is $27.79/MWh.[12] Existing low-impact hydroelectric generators in New York generate about 360 GWh per year, and these resources' attributes would export to New England if the energy from the facilities is also exported.

Other New England RPS Classes

The other tiers or classes of New England RPS programs generally offer only minimal compensation (typically less than $5/MWh, and much less in some cases). However, the existing independent generation fleet in New York would be eligible to supply attributes for these programs. Of the 9.3 TWh of total generation, 4.2 TWh are not eligible for a New England Class I program or Massachusetts Class II, but are eligible for Connecticut or Maine Class II, New Hampshire Class II, Rhode Island's "existing resources" tier, or Vermont's "total renewable energy" tier. Of these, only Vermont's has a rising obligation over time.

PJM

Of the RPS programs in PJM, the Maryland RPS is the most attractive option for existing New York resources without higher-paying options in New England. More than 2.5 TWh of New York hydropower and all of New York's woody biomass resources would be eligible in Maryland. In contrast to exports to New England, there are transmission costs associated with exports to PJM from the NYISO region that

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[11] See https://macleanenergy.com/83d/ for the documentation, timeline, and submitted bids from this request for proposals.

[12] NC Clean Energy Technology Center/DSIRE, "Renewable Portfolio Standard," http://programs.dsireusa.org/system/program/detail/479 , accessed December 20, 2017/

are not compensated for by differences in locational marginal price across the border. These costs may or may not exceed the value of PJM RECs, which are currently in the range of $3–5/MWh.[13] In the past few years, PJM REC prices have been somewhat higher, although still typically less than $10/MWh.

Voluntary markets

Renewable attributes may be separated, or "un-bundled" from a generator's energy, and sold separately to a willing buyer. Buyers may wish to make green claims without necessarily procuring the energy associated with the renewable resources. For example, they may be in a state without retail choice. There is no centralized tracking system for the transfer of attributes in this voluntary market. In fact, some attributes that New York is claiming in its Baseline may have been sold to non-New York buyers through bilateral or other contracts. Voluntary RECs tend to have the lowest prices—measured in cents per MWh.[14] This typically makes them the least attractive option for generators. However, the only eligibility requirement is agreement from the buyer, and there is no overhead cost from requiring sales of energy into a particular region. As a result, generators may find that this is the most profitable option available to them. Voluntary sales could result in significant loss of attributes from New York, although the lack of tracking means that some fraction of them could be enabling in-state green claims.

Existing generators which have short-term contracts with their interconnecting utility may have contract terms which also transfer attribute ownership. If the utility retains and retires those attributes they are effectively voluntary New York RECs. The interconnecting utility has significant market power in its interactions with small generators due to its economies of scale and scope for using the generator's energy and capacity output. It may therefore be able to use this power to restrict the ability of generators to choose other, more lucrative, transactions for their attributes.

2.2. Retirement Risk

Wholesale energy market prices in NYISO have fallen considerably over the last several years and are not expected to rise soon. Prices may also continue to fall as more Tier 1 resources enter the market and bid zero or even negative prices. While low capacity prices may rise to partly compensate for low energy prices, the resources most at risk of retirement (e.g. small hydroelectric plants) are not generally well suited to capture such gains due to seasonal generation patterns or intermittent production.

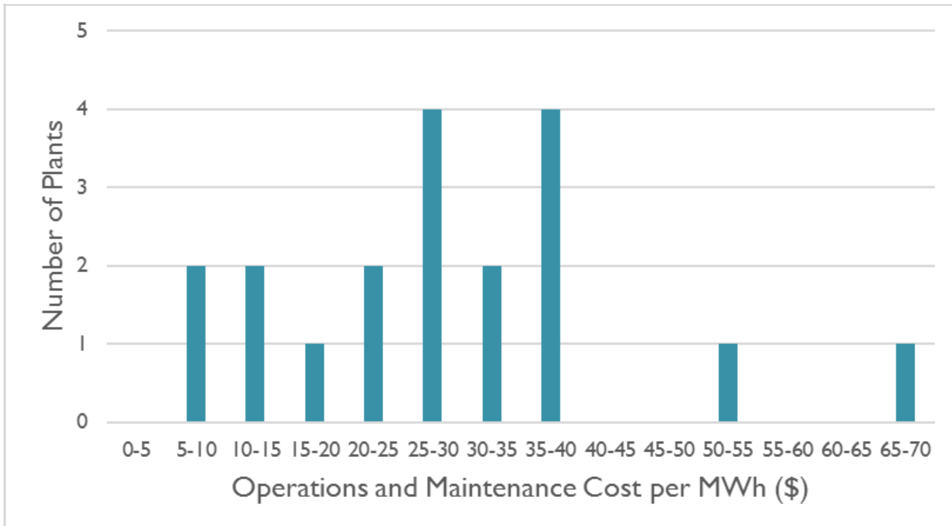
Generators without a "premium" value in New York or elsewhere receive only the wholesale energy and capacity prices, plus voluntary or low-value RPS compliance market REC prices. These include older hydroelectric facilities that are not certified as low impact, as well as woody biomass electric generators. Extended periods of losses at such facilities will result in plant closures, with the associated loss of Baseline.

[13] Indicative REC prices from Karbone, August 30, 2017.

[14] *Ibid*.

Losses are determined by the comparison of ongoing costs and revenues. Ongoing costs vary greatly among facilities, and they can vary over time as capital needs arise. We conducted a survey of ACE NY hydroelectric members that provides an indication of the spread in operations and maintenance (O&M) costs among small plants. Average O&M expenses across these under-10 MW plants is about $28/MWh, with a standard deviation of $15/MWh.

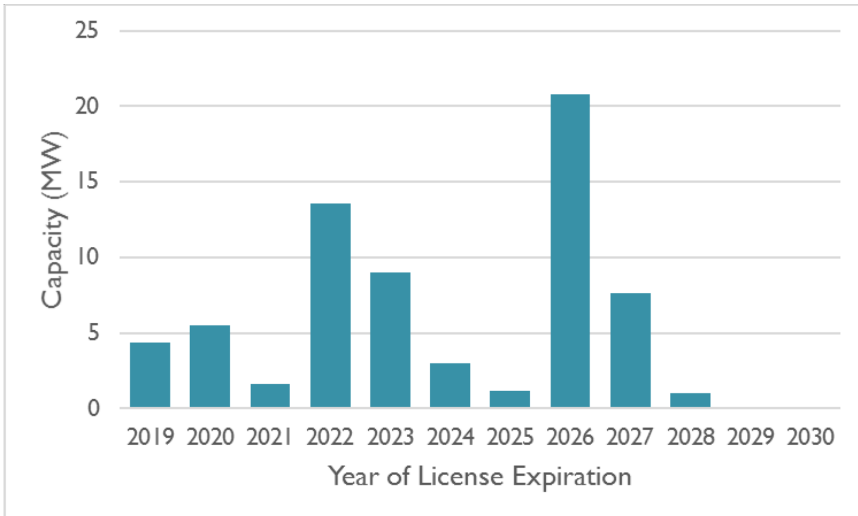
Figure 6: Distribution of O&M costs per MWh from a sample of 19 ACE NY member plants smaller than 10 MW



Merely recovering O&M costs means an increased risk of closure at relicensing or when capital investment is needed. FERC re-licensing is likely to create significant capital costs and to-go costs as used to date in Maintenance Program contracts have not provided sufficient support to allow plants to make the necessary investments. Relicensing can also result in reduced production or income due to required changes in water flow.

As shown in Figure 7, 68 MW of hydro plants under 10 MW and without LIHI certification (and thus without any current substantial REC market options) have licenses expiring in 2030 or before.

Figure 7: Capacity of small, non-LIHI hydroelectric plants with expiring FERC licenses, by year



3. THE STATUS QUO AND DPS STAFF PROPOSAL

Under current law and PSC Orders, New York load-serving entities have no obligation to purchase or retire renewable attributes from generators that are not participants in Tier 1 of the present RES (including resources under contract from the Main Tier of the previous RPS). The DPS Staff have proposed changes to the Maintenance Tier (Tier 2) of the RES in their report issued on October 19, 2017.[15] This section analyzes the potential near- and medium- -term impacts of an unchanged status quo or the status quo if the DPS Staff Proposal were implemented as proposed. We have analyzed the period 2019 to 2023 to reflect that fact that program changes would likely not be fully implemented until 2019, and projections past 2023 are increasingly uncertain due to changes in market conditions and rules (including RPS rules in New York and other states as well as incorporation of carbon pricing into wholesale markets).

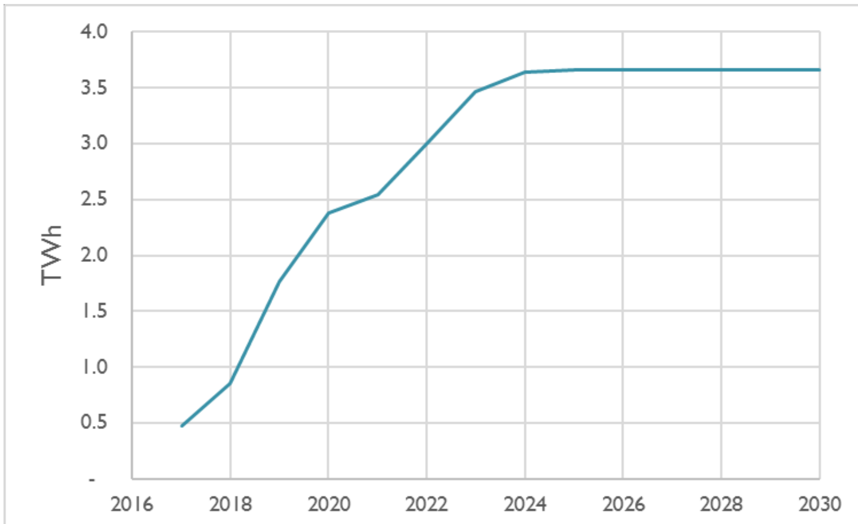
3.1. Loss of Baseline to Exports

The primary risk that New York faces in the status quo, unaffected by the DPS Staff Proposal, is that existing resources will export their attributes from New York along with their energy in response to RPS policies in nearby states. This will result in an erosion of the Baseline. Contracts such as the Main Tier RPS contracts for Tier 1 resources are the primary mechanisms keeping these attributes in New York today, and as resource contracts expire we expect exports to increase.

[15] New York Department of Public Service, "Staff Report Regarding Retention of Existing Baseline Resources Under Tier 2 of the Renewable Energy Standard Program," Case 15-E-0302, issued Oct. 19, 2017.

Exports of Baseline resources to New England's Class I markets (that is, exports additional to the 1 TWh that were already exported in 2014) will rise from about 470 GWh in 2017 to 3,700 GWh by 2025. Figure 8 shows this increase. These Baseline exports represent 8.9 percent of the Baseline and 2.6 percent of the expected 2030 sales. If New York does not acquire new contracted resources eligible for Tier 1 to replace these losses, the amount of renewable electricity that New York could claim would fall from 29 percent of 2030 load in 2014 to 27.6 percent in 2020 and 26.7 percent in 2025.

Figure 8: Expected New England Class I exports of Baseline resources by year



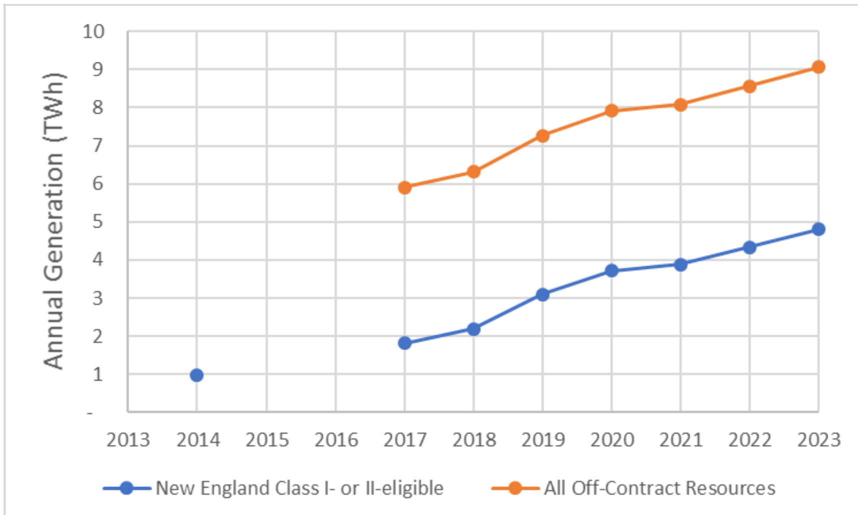
About 360 GWh per year of New York Baseline generation is eligible for Class II in Massachusetts, and in our status quo model case we assumed it would be exported to capture the available REC value under that program.

Backsliding would begin by 2019, when generators with expiring NYSERDA contracts, along with uncontracted older resources, find opportunities to export that exceed the amount of new Tier 1 resources coming online. Replacing the 2.1 TWh of increased likely REC exports to New England in 2019 with new wind generation would require more than 725 MW of new resources.[16] The challenge grows over time: New York would have to acquire another 1.7 TWh of Tier 1 resources by 2023 (for a total of 3.8 TWh). This is equivalent to siting and constructing about 1,300 MW of new wind by 2023. If Tier 1 resources were to demand a REC price of $30 in 2023, this would mean an annual cost of $115 million.

Figure 9 shows the increasing amount of New York generation that is off-contract and eligible to export, including the fraction that is eligible for Class I treatment in New England or Class II in Massachusetts.

[16] This assumes a 33 percent capacity factor.

Figure 9: The amount of independent existing New York generation that is not contracted in New York and eligible to export to New England or otherwise sell RECs outside of New York, 2017 to 2023. The 2014 data point is the actual REC exports to New England in that year.



3.2. Loss of Baseline to Voluntary REC Sales and Minor REC Markets

About 4 TWh of annual generation in 2023 will be uncontracted and not eligible for premium treatment in New England RPS programs. These generators have motive and opportunity to find markets for their renewable attributes in either the voluntary markets or the less lucrative REC markets in other states, such as Maryland, Vermont Tier 1, Rhode Island's existing tier, and Maine Class II. Generators will also look for opportunities to pair with new renewables, as in the recent Massachusetts RFP. Generators will balance the value of their attributes to different buyers with the transaction costs associated with exporting bundled attributes or finding voluntary bilateral buyers. If a net profit of even a few cents per MWh is achievable, which we believe to be the case, generator owners are likely to take the opportunity. This means New York will be left with even fewer attributes to claim toward its Clean Energy Standard goals.

To avoid net backsliding due to losses to voluntary markets and minor REC markets, New York will have to acquire an extra 4.2 TWh of Tier 1 resources by 2023, in addition to the resources required to offset exports to New England. This is equivalent to siting and constructing more than 1,400 MW of new wind.[17] If Tier 1 resources demand a REC price of $30 in 2023, this would mean an annual cost of $127 million.

[17] This assumes a 33 percent capacity factor.

3.3. Retirement Risk and the Maintenance Program for Small Hydroelectric Plants

We developed assumptions regarding the continued operation of small hydroelectric plants and the cost of the Maintenance Program under both the status quo and the recent DPS Staff proposal.

We have not attempted to quantify the impact of either case on New York's operating biomass electric facilities—these plants have their own challenging economics and are long-term participants in the Maintenance Program. Our analysis operates at a generic level, above the level of plant-specific issues such as those which dominate consideration of these facilities.

Current Maintenance Program

The current Maintenance Program offers the opportunity for plant-by-plant consideration of the "to-go" costs necessary to avoid the closure of the plant. However, it does not account for the need for capital investment. Nor does it account for the need for plant owners to achieve a return on equity or pay for debt incurred to fund past capital improvements. As such, it may be insufficient to prevent plants from closing, especially at the time of FERC relicensing. We have assumed in our analysis of the status quo Base Case that half of plants under 10 MW retire when their current FERC licenses expire.[18] We assume that all such plants retire because low wholesale energy prices, lack of other policy support, and lack of Maintenance Program support for the financial costs of capital investment make the risk of substantial investment for an additional 40 years of operation too high to proceed.

For operating plants, we estimated the fraction of small hydroelectric plants under 10 MW that require compensation above current and projected market energy prices from a survey of ACE NY members (see Section 2.2). Half of these generators require some additional compensation to avoid retirement, and the average amount of break-even need between 2019 and 2023 is $13/MWh.

[18] This assumption has no effect on the relative cost of the policy options, because these plants are assumed to be selling their RECs to the extent possible in advance of their closure.

DPS Staff Proposal

DPS Staff proposed a set of changes to the Maintenance Program. These include the establishment of a simpler application option, the imposition of soft caps in the compensation at the level of the social cost of carbon minus RGGI (and a hard cap at the Tier 1 REC price), and the inclusion of a process to partly account for capital investments. However, we calculate that this program would be insufficient to avoid plant retirements. This is because some plants require more than the Tier 1 REC price to remain in operation, which is driven in part by a growing separation between the wholesale energy price forecast incorporated in DPS Staff's proposal and the actual low energy prices seen and projected in the market.

In the DPS Staff case, we modeled the compensation that plants would be eligible for under the DPS Staff Proposal and assumed that plants would not necessarily retire at the time of FERC license expiration, in recognition of Staff's intention to allow for capital investment recovery. However, we estimate that the approximately 10 percent of small hydroelectric plants which require compensation above the Tier 1 REC price to be profitable would retire over the next five years; this would be a loss of about 40 MW of capacity. We estimate that 15 percent of plants would qualify for assistance under the DPS Staff rubric, and we calculated the average level of Maintenance payment that these plants would be paid under the proposed rubric: $18/MWh.

Although not the subject of this report, we do note that the DPS Staff Proposal responds to some of the concerns and criticisms of the Maintenance Tier that have been expressed during the Clean Energy Standard, but not all. For example, historically, some companies have been unwilling to participate in the Maintenance Tier as demonstrating financial hardship and allowing the financial information of the facility to be subject to PSC scrutiny would have raised other operating issues.

Existing Generators as Distributed Generation

Theoretically, a renewable energy generator currently participating in the wholesale markets, such as a 2 MW hydroelectric plant, does have the option of re-developing as a distributed resource such as a customer-sited generator, a remote net-metered generator, or a community distributed generation project. Around 2014, for example, some existing hydro facilities were exploring options for gaining access to retail net metering compensation, essentially by becoming behind-the-meter resources. This type of re-development was very much in keeping with the REV philosophy: market compensation was driving private investment and allowing these aging facilities to receive the investment they needed to continue to operate and maintain their RECs in New York.

One decision in the Value of Distributed Energy Resources (VDER) proceeding has closed down this option. In the Phase One Value Stack approach, a hydro project that becomes behind-the-meter (by recruiting subscriptions and becoming a community hydro project) is not eligible for the E value because it is not a "new" generator. There is not a strong rationale for undervaluing the environmental attributes of an older DER as compared to a new DER. This decision is at odds with a policy goal of keeping existing generation in-state and contributing to the 50% renewable energy goal.

3.4. Summary of Resulting New York Claims and Costs

Without a Tier 2 obligation on load-serving entities, the only renewable attributes New York is assured to be able to claim from existing independent renewable generators are the attributes obtained in exchange for support under the Maintenance Program. New York is therefore faced with the choice to either increase procurement of new Tier 1 renewable attributes above the level considered during the development of the Clean Energy Standard or slide below the Baseline level of renewable energy served to New York customers and risk missing the 2030 target.

New York's projected 2030 load is 141 TWh. In the CES analysis, Baseline resources were assumed to make up 41.3 TWh of this, or about 29 percent. If generators are able to take their economically rational actions and sell renewable attributes, by 2019 the Baseline will contribute only 25 percent. By 2030, it will approach 23 percent. Procurements by 2019 of new renewables (online after January 1, 2015) from either the Main Tier of the RPS or Tier 1 of the RES are not expected to amount to the 4.5 percent of 2030 sales (6.3 TWh) required to keep the state from backsliding.

If New York intends to avoid or minimize backsliding by acquiring Tier 1 RECs in excess of those that were contemplated in the Order establishing the Renewable Energy Standard, its ratepayers will need to pay for either expanded Tier 1 procurements in the near term or import of qualifying RECs from other jurisdictions. We have estimated the cost of acquiring these RECs for the 2019–2023 period. The exact number of RECs to be acquired depends on the utilization of the Maintenance Program (which procures RECs from existing resources) and the extent of retirements.

Our modeling indicates different Maintenance Program costs, REC procurements, and retirements, based on whether the current Maintenance Program continues or is replaced by the DPS Staff Proposal. The current Maintenance Program is more administratively burdensome but has the potential to be more generous than the DPS Staff Proposal. In particular, we believe that the case-by-case consideration in the current program would avoid more retirements, while the DPS Staff Proposal's caps on maintenance payments would result in an increased risk of retirement among the highest-cost generators.

Based on the distribution of hydroelectric generator O&M costs described in Section 2.2 and our projections of wholesale energy prices, we estimate that about 40 percent of existing hydro generators under 10 MW are at risk of retirement in the next five years without some effective form of support (such as a Maintenance Program). The plants most at risk of retirement are those due for relicensing at the FERC, of which there are about 34 MW between now and 2023. Maintenance support that addresses only the limited set of costs considered under the current Maintenance program may not be sufficient to encourage the necessary capital investment, associated debt, and risk of reduced power production associated with relicensing.

Balancing the advantages and disadvantages of both the status quo and the DPS Staff proposal, we estimate that:

- Retirements in the status quo case would result in a loss of 59 GWh of annual generation by 2030, while retirements in the DPS Staff Proposal case would result in a loss of about 140 GWh in the next five years.

- Maintenance payments in the status quo case would total $7 million per year for 530 GWh, while in the DPS Staff Proposal case they would total $3.6 million per year for 200 GWh.

Maintenance payments in the Status Quo case avoid more retirements than the DPS Staff proposal case because the Status Quo can support needs above the "SCC minus RGGI" level. The payments per MWh in the Status Quo case are lower on average because they are available to more generators because they can better reflect lower energy price forecasts.

After accounting for the retirements, costs, and renewable attribute acquisitions associated with each Maintenance Program, we calculated the resulting total ratepayer cost under each program design for the combination of maintenance payments and Tier 1 RECs. We assumed that the Tier 1 program would be expanded to acquire 33 TWh of replacement RECs over the 2019 to 2023 period, spread between years in the same fashion as the Tier 2 RECs acquired under three of the five policy options we consider below. This allows a relatively close apples-to-apples comparison.

- We estimated the total ratepayer cost over the 2019 to 2023 period in the status quo case to be $657 million, in present value terms. Ratepayers would acquire 33.0 TWh of renewable attributes in exchange for that expenditure (30.4 TWh of Tier 1 resources plus 2.6 TWh of Tier 2 Maintenance resources). The average cost of per REC that New York can claim would be $28.04/MWh (using non-discounted costs and MWh). If the status quo were continued to 2030, we estimate the present value of its cost would be $1.51 billion to acquire 95.2 TWh of renewable attributes.

- Under the DPS Staff Proposal the present value of the 2019–2023 cost would be $684 million. Ratepayers would acquire 33.0 TWh of renewable attributes in exchange for that expenditure (32.5 TWh of Tier 1 resources plus 0.5 TWh of Tier 2 Maintenance resources). The average cost of per REC that New York can claim would be $29.17/MWh. If the DPS Staff case were continued to 2030, we estimate the present value of its cost would be $1.57 billion to acquire 95.2 TWh of renewable attributes.

4. A Tier 2 Obligation Would Be Cost-Effective, Fair, and Efficient

4.1. Policy options

It would be more cost-effective for New York to acquire renewable attributes from the existing in-state, independent resources and thereby maintain the Baseline than for New York to make up for erosion of the Baseline by acquiring additional Tier 1 resources. Tier 1 resource acquisition could then remain focused on building above the Baseline to make real progress towards 50 percent. This section describes a set of policy options that we modeled to demonstrate the advantages and disadvantages of various policy approaches the state could take to capture this benefit.

Each of these options includes a requirement for load-serving entities to acquire and retire their pro rata share of RECs acquired from Tier 2 resources. The amount varies by policy.

In each case, we modeled a cap on the size of hydroelectric facilities eligible to participate at 60 MW. This makes clear that large existing hydroelectric generators in New York or in nearby jurisdictions are not the intended resources for this program. For Tier 2 RECs to be eligible, energy must be delivered to New York along with the attributes.

The five policies we modeled were:

1. Tier 2 RECs purchased from all comers at 75 percent of the average Tier 1 REC price for each year;
2. Tier 2 RECs purchased from all comers at 100 percent of the average Tier 1 REC price for each year;
3. Tier 2 RECs purchased from all comers at the social cost of carbon emission avoided by those generators, adjusted for expected RGGI revenues;
4. Tier 2 RECs purchased from all comers at the social cost of carbon emission avoided by those generators, adjusted for expected RGGI revenues and for expected market energy prices; and
5. A rolling Tier 2 REC auction in which the equivalent of one third of the off-contract existing independent in-state generation in the Baseline is acquired each year through competitive procurement.

Policy options 1 through 4 set the price rather than the quantity of RECs to be acquired. Depending on the market prices of RECs in New England, these policies could result in New York acquiring significantly more RECs than the amount of in-state generation they are intended to retain. To avoid over-acquiring and undercutting Tier 1, we have modeled them as though New York applies a cap at the amount of generation acquired at the level of the expected output from in-state existing independent generators that are not under NYSERDA contracts.

Commerce Clause concerns would likely prevent New York from restricting eligibility to only in-state resources for any policy option. The final mix of New York and out-of-state resources contributing is outside of the resolution of our modeling.

As discussed above, we have analyzed the period 2019 to 2023 to reflect that fact that program changes would likely not be fully implemented until 2019, and projections past 2023 are increasingly uncertain due to changes in market conditions and rules. Table 2 summarizes the costs and benefits of each of these policies, compared with the Base Case, which is the policy status quo (the implications of which are described above).

Table 2: Present value costs of each policy option from 2019–2023, along with per-MWh costs (not present-valued) of renewable energy New York can claim in each case

Policy Option	Tier 1 RECs Acquired (TWh)	Tier 2 RECs Acquired (TWh)	Cost of Tier 1 RECs ($ millions)	Cost of Tier 2 RECs ($ millions)	Cost of Maint. Prg. ($ millions)	Total Cost ($ millions)	Cost vs. Base Case ($ millions)	Avg. REC Cost ($/MWh)[19]	Avg. REC Cost vs. Base Case ($/MWh)
Base Case/Status Quo	30.4	2.6	632		25	657		28.04	
DPS Staff Proposal	32.5	0.5	677		6	684	27	29.17	1.12
1: 75% of Tier 1 Avg.		33.0		515	7	522	(135)	22.26	($5.79)
2: 100% of Tier 1 Avg.		36.3		760	0	760	103	29.12	1.08
3: Carbon Value		33.0		475	5	480	(177)	20.43	($7.61)
4: Market Responsive Carbon Value		33.0		457	5	462	(195)	19.60	($8.44)
5: Rolling REC Auction		26.9		238–387	42	280–429	(377)–(228)	$14.71–$22.25	($13.34)–($5.80)

[19] Average REC costs are the costs for Tier 1 and Maintenance RECs in the Base Case/Status Quo and DPS Staff Proposal cases, and Tier 2 and Maintenance RECs in the five policy option cases.

4.2. Option 1: 75 Percent of the Tier 1 REC Price

In this policy option, New York would offer 75 percent of the most recent average Tier 1 REC price to all comers for Tier 2 resources, and then require load-serving entities (LSEs) to acquire and retire their pro rata share of the Tier 2 RECs acquired through that process. This option corresponds to legislation that has been recently considered in the New York legislature.

We expect New York Tier 1 RECs to be somewhat more costly than New England Class I RECs on average over the five-year study period, although the relative prices vary year by year.[20] Our forecasts for REC price can be found in the Appendix. In 2019 and 2020, we project that New England Class I REC prices will remain above 75 percent of the average New York Tier 1 price, so the only resources that New York's policy will retain in those two years are the resources not eligible for Class I in a New England state or Massachusetts Class II. Beginning in 2021, we project that New York's average Tier 1 prices will rise, and New England Class I REC prices will fall, to the point that 75 percent of the Tier 1 is greater than the New England Class I market price. At that point, New York will both retain all of its Baseline (minus the Massachusetts Class II-eligible RECs) and attract home the existing resources outside the Baseline that have historically been exporting to New England Class I.

We presume that New York would not be able to adjust Tier 1 procurement quickly enough to procure additional Tier 1 RECs to replace the Baseline lost to New England in 2019 and 2020. As a result, the year-by-year results can be summarized as shown in Table 3.

We estimate that a small number of hydroelectric and biomass facilities would require additional maintenance-type financial support, above the Tier 2 REC price, to remain in operation, and that New York would support them with an average of $9/MWh. This results in an additional cost, also shown in Table 3. The Maintenance cost shown here is the incremental cost; all Maintenance plants also receive the REC value.

Table 3: Five-year benefits and costs of Policy Option 1.[21]

	Tier 2 RECs acquired by policy (TWh)	Policy cost ($ millions)	Maintenance cost ($ millions)	Cost vs. Base Case ($ millions)
2019	4.2	79.6	1.9	(18.0)
2020	4.2	86.2	1.9	(19.1)
2021	7.7	170.8	1.9	(46.2)
2022	8.2	174.0	1.9	(48.1)
2023	8.7	214.0	1.9	(59.3)

[20] New England market REC prices are generally lowered by the state procurement processes that occur outside those markets, whereas New York's Tier 1 prices are set by its state procurement.

[21] Red values are negative, indicating savings.

The present value of this policy option's costs from 2019 to 2023 would be $484 million; New York would acquire 33.0 TWh of Tier 2 RECs for this expense. The average REC cost across this period is $22.26/MWh (using non-discounted costs and MWh). This represents a savings of $135 million in present value or $5.79/MWh (non-discounted) from the Base Case. If the policy were continued to 2030, we estimate the present value of its cost would be $1.07 billion and the state would retain 81.3 TWh of Tier 2 RECs.

4.3. Option 2: 100 Percent of the Tier 1 REC Price

In this policy option, New York would offer the most recent average Tier 1 REC price to all comers for Tier 2 resources, and then require LSEs to acquire and retire their pro rata share of the Tier 2 RECs acquired through that process.

In 2019, we project New England Class I prices will exceed the New York Tier 1 price, so Class-I eligible Baseline resources will export. In 2020 and after, we project that New York's average Tier 1 prices will exceed New England Class I REC prices. Under this policy, as a result, New York will both retain all of its Baseline (except the Massachusetts Class II-eligible RECs) and attract home the existing resources outside the Baseline that have historically been exporting to New England Class I markets. The year-by-year results can be summarized as shown in Table 4.

We assume that under this policy framework, no facilities would be offered maintenance support above the Tier 1 REC price, so there is no Maintenance Program cost.

Table 4: Five-year benefits and costs of Policy Option 2

	Tier 2 RECs acquired by policy (TWh)	Policy cost ($ millions)	Maintenance cost ($ millions)	Cost vs. Base Case ($ millions)
2019	4.2	106.1	0.0	6.7
2020	7.6	207.1	0.0	99.9
2021	7.7	227.7	0.0	8.8
2022	8.2	232.0	0.0	8.0
2023	8.7	285.3	0.0	10.1

The present value of this policy option's costs from 2019 to 2023 would be $760 million; New York would acquire 36.3 TWh of Tier 2 RECs for this expense. The average REC cost across this period is $29.12/MWh (using non-discounted costs and MWh). This represents a net cost of $103 million in present value or $1.08/MWh (non-discounted) relative to the Base Case. If the policy were continued to 2030, we estimate the present value of its cost would be $1.65 billion and the state would retain 98.6 TWh of Tier 2 RECs.

4.4. Option 3: Carbon Value

In this policy option, New York would internalize the otherwise-externalized carbon value of existing generators' output. New York would offer the social cost of carbon minus the expected RGGI clearing price, adjusted to energy terms, to existing generators. We assume that New York would use the same formulation of the social cost of carbon and RGGI prices as used for the Zero Emission Credit (ZEC) program. This credit value would be available to all comers for Tier 2 resources, and New York would then require LSEs to acquire and retire their pro rata share of the Tier 2 RECs acquired through that process.

In 2019 and 2020, we project that New England Class I REC prices will remain above the social cost of carbon minus RGGI, so the only resources that New York's policy will retain in those two years are the resources not eligible for Class I in a New England state or Massachusetts Class II. Beginning in 2021, we project that the combination of a rising social cost of carbon, and falling New England Class I REC prices will attract otherwise exported resources back to New York. New York will both retain all of its Baseline (except for the Massachusetts Class II-eligible RECs) and attract home the existing resources outside the Baseline that have historically been exporting to New England Class I.

We presume that New York would not be able to adjust Tier 1 procurement quickly enough to procure additional Tier 1 RECs to replace the Baseline lost to New England in 2019 and 2020. As a result, the year-by-year results can be summarized as shown in Table 5.

We estimate that a small number of hydroelectric and biomass facilities would require additional maintenance-type financial support, above the social cost of carbon minus RGGI, to remain in operation, and that New York would support them with an average of $6/MWh during 2019–2023. This results in an additional cost, also shown in Table 5. The Maintenance cost shown here is the incremental cost; all Maintenance plants also receive the REC value. The need for maintenance support falls over time as the social cost of carbon rises.

Table 5: Five-year benefits and costs of Policy Option 3

	Tier 2 RECs acquired by policy (TWh)	Policy cost ($ millions)	Maintenance cost ($ millions)	Cost vs. Base Case ($ millions)
2019	4.2	72.7	1.8	(24.9)
2020	4.2	82.1	1.3	(23.8)
2021	7.7	151.2	1.3	(66.4)
2022	8.2	175.4	1.0	(47.6)
2023	8.7	186.0	1.0	(88.3)

The present value of this policy option's costs from 2019 to 2023 would be $480 million; New York would acquire 33.0 TWh of Tier 2 RECs for this expense. The average REC cost across this period is $20.43/MWh. This represents a savings of $177 million in present value or $7.61/MWh (non-discounted) from the Base Case. If the policy were continued to 2030, we estimate the present value of its cost would be $1.26 billion and the state would retain 95.2 TWh of Tier 2 RECs.

4.5. Option 4: Market-Responsive Carbon Value

This policy option builds on the Carbon Value policy by adding a provision that limits the size of the REC payment based on market energy prices. We have assumed the same policy structure as adopted for the ZEC program. This credit value would be available to all comers for Tier 2 resources, and New York would then require LSEs to acquire and retire their pro rata share of the Tier 2 RECs acquired through that process. The ZEC structure has an energy price level ($39/MWh in that case) above which the value of the payment would be reduced on a dollar-for-dollar basis. Recognizing that market energy prices continue to change, we have evaluated this policy with the assumption that the energy price level at which the REC price would be reduced would be $30/MWh, rather than $39/MWh. If we retained the $39/MWh value, this policy would be nearly identical to the Carbon Value option because we do not project the relevant energy prices rising above $39/MWh until almost 2030.

Our modeling showed that even the $30/MWh market level only begins to affect the REC price in 2022, so the policy cost and generator behavior impacts are small compared to the Carbon Value policy in the 2019–2023 analysis period. In the longer term, however, if energy prices do rise and stay above $30/MWh, this policy option could be significantly less costly than the pure Carbon Value. Generator behavior in all but 2030 is the same under this policy as under the Carbon Value option. (In our admittedly uncertain assessment of 2030 itself, the resulting REC price falls below the New England Class I value and significant resources are lost to New England compliance.)

Table 6 shows the costs and benefits of the first five years of this policy; note that the first three years are identical to the Carbon Value (Option 3) case.

Table 6: Five-year benefits and costs of Policy Option 4

	Tier 2 RECs acquired by policy (TWh)	Policy cost ($ millions)	Maintenance cost ($ millions)	Cost vs. Base Case ($ millions)
2019	4.2	72.7	1.8	(24.9)
2020	4.2	82.1	1.3	(23.8)
2021	7.7	151.2	1.3	(66.4)
2022	8.2	167.4	1.2	(55.5)
2023	8.7	165.8	1.5	(108.0)

The present value of this policy option's costs from 2019 to 2023 would be $462 million; New York would acquire 33.0 TWh of Tier 2 RECs for this expense. The average REC cost across this period is $19.60/MWh. This represents a savings of $195 million in present value or $8.44/MWh (non-discounted) from the Base Case. If the policy were continued to 2030, we estimate the present value of its cost would be $1.03 billion and the state would retain 90.6 TWh of Tier 2 RECs.

4.6. Option 5: Rolling REC Auction

In contrast to the options involving a price established by the State, New York could choose to use a competitive procurement process to retain enough Tier 2 RECs to avoid loss of Baseline. We analyzed an option in which New York would procure one third of the otherwise-lost independent Baseline each year, for three-year contracts. In that way, by 2021 the state would have recovered lost Baseline and have a market-responsive structure in place to ensure that the full baseline is available for state policy objectives and claims. As with the other options, LSEs would be required to procure their pro rata shares of Tier 2 RECs.

This policy does not acquire the entire lost Baseline every year because generators that roll off NYSERDA Main Tier RPS contracts would have a short window between the end of their contracts and beginning this annual contract process. However, this is about a 5 percent effect and fades away as the last generators come off their NYSERDA contracts.

In order to have a reasonably well-functioning market and a reasonable resulting clearing price, the policy should be designed to mitigate market power and direct bids to be reasonable. This would include, for example, a cap on bids at the Tier 1 REC price (or a slight discount) and eligibility rules that allow resources from neighboring states and provinces to compete fairly.

Unlike the other policy options considered, this policy option acquires a known quantity of renewable attributes each year. However, given uncertainty in market forces and the bids of each generator, the cost per REC is more uncertain than in the other options. For this reason, we modeled a high-bid and a low-bid scenario and present the results as a range. These scenarios reflect the uncertainty in the suite of resources that will respond to the solicitation, and in their bidding strategies. Under this option, the State could use a competitive auction with a market clearing price, which is different than the approach used in New York's current Tier 1 REC procurement, or use an as-bid approach.[22]

In the high-bid case, we assume that the marginal resource setting the clearing price every year for the competitive market is choosing between New England Class I and New York. We further assume that this resource is willing to take a 5 percent discount on the projected New England Class I price in exchange for the certainty of the three-year contract. (This case could also occur if resources use a bidding strategy tied to the belief that the marginal resource is a Class-I-eligible resource.)

In the low-bid case, we assume that hydroelectric plants with low costs set the REC price in the first year at $10/MWh, somewhat higher-case hydroelectric plants set the price for the second competition at $15/MWh, and resources with New England Class I options set the price only in the third year, when lower cost resources are all under contract. This progression corresponds to the amount of generation available from hydroelectric generators and the amounts that would be procured under each year's procurement. If New York attracted significant interest from non-Class-I-eligible resources from outside the state, the third year might also clear at a lower price. Thus, the low-bid case does not reflect a floor on New York's costs.

[22] Economic theory asserts that in a competitive and well-informed process, these two approaches would have equivalent outcomes.

We assume that New York would separately maintain a Maintenance Program for facilities that are not able to win a contract through this process and would close without some higher REC compensation. This would be a relatively small number of plants, but they necessarily require REC compensation above the clearing prices of the competitive process. We have assumed this to be $20/MWh, rising with inflation. To avoid retirements, this is somewhat more generous that the Status Quo or DPS Staff proposal's net effects, and it is used by all plants with a need. The Maintenance cost shown here reflects the total compensation awarded to the Maintenance plants; they do not also have auction contracts.

Table 7 shows the costs and benefits of the first five years of this policy presented as a range between the low-bid and high-bid scenarios.

Table 7: Five-year benefits and costs of Policy Option 5

	Tier 2 RECs acquired by policy (TWh)	Policy cost ($ millions)	Maintenance cost ($ millions)	Cost vs. Base Case ($ millions)
2019	2.3	17.8–43	10.9	(70.8)–(45.5)
2020	4.4	49.2–97.6	11.1	(46.9)–1.5
2021	6.2	79.8–132.1	11.3	(127.7–(75.5)
2022	6.8	91.1–136	11.5	(121.4)–(76.5)
2023	7.2	100.6–132.4	11.8	(162.8)–(131.0)

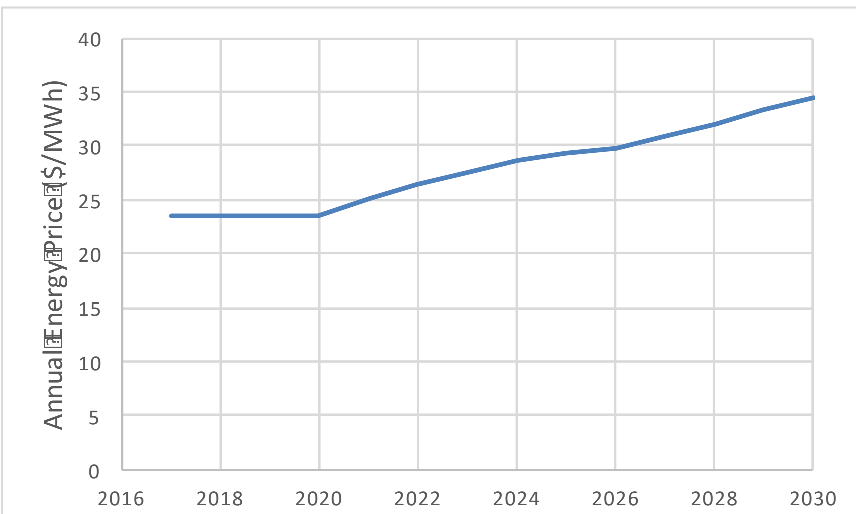
The present value of this policy option's costs from 2019 to 2023 would be between $280 and $429 million; New York would acquire 26.9 TWh of Tier 2 RECs for this expense. The average REC cost across this period is between $14.71/MWh and $22.25/MWh. This represents a savings of $228 to $377 million in present value or $5.80/MWh to $13.34/MWh (non-discounted) from the Base Case. If the policy were continued to 2030, we estimate the present value of its cost would be between $729 and $1,000 million and the state would retain 77.3 TWh of Tier 2 RECs.

APPENDIX: ENERGY AND REC PRICE FORECASTS

Energy Price Forecast

We developed an energy price forecast for NYISO based on energy prices in the last two years combined with the U.S. Energy Information Administration's 2017 Annual Energy Outlook (AEO). We assumed that wholesale energy market prices would remain flat in nominal terms through 2020, and then rise at the rate of increase in the AEO Reference Case for natural gas consumed in the Mid-Atlantic electric power sector. This forecast balances competing forecasts: AEO projects a near-term rise in natural gas prices, while the futures markets for natural gas is nearly flat in nominal terms to at least 2020.[23] We used the historical ratios of energy prices in the various NYISO zones to develop zone-specific forecasts. Figure 10 shows the energy price forecast for Zone E (Mohawk Valley), which is home to the plurality of the generators considered in this report.

Figure 10: Wholesale energy price forecast for Zone E (Mohawk Valley)



REC Price Forecasts

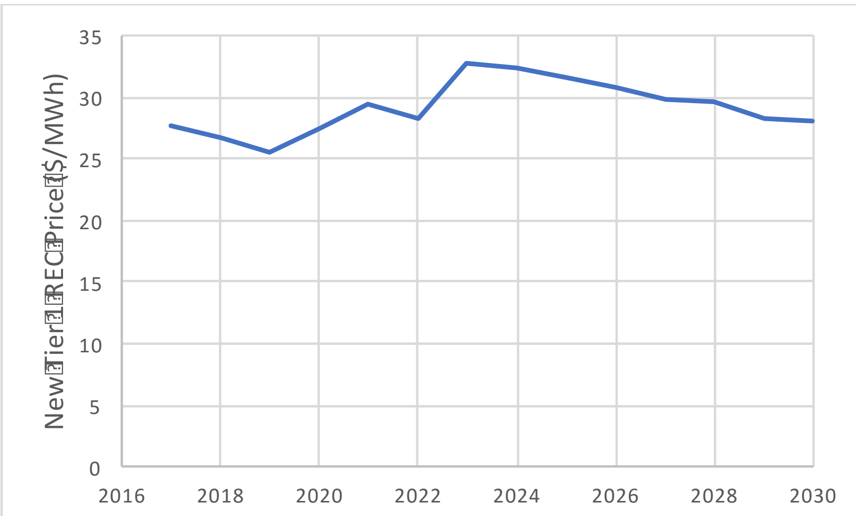
New York Tier 1

We based our projected REC prices for the New York Tier 1 process on the difference between the cost to develop new large onshore wind projects and expected revenues from wholesale markets. To develop such a forecast, we relied upon an analysis of the Massachusetts RPS that Synapse recently completed in partnership with Sustainable Energy Advantage for a projection of the levelized cost of

[23] Based on Henry Hub Natural Gas Futures quotes from the CME Group, accessed from http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html on December 7, 2017.

new onshore wind generation in the region.[24] Combining that projection with the NYISO energy price forecast allowed us to develop a REC price projection. Historically, average NYSERDA REC prices have covered only about two thirds of the difference between energy market projections and the cost to develop wind; we applied a factor to normalize for that market effect.[25] Figure 11 shows the resulting REC price for each year.

Figure 11: Forecast Tier 1 REC price from annual NYSERDA procurement



New England Class I

Our New England Class I REC price forecast was also informed by the recent Massachusetts RPS project.[26] That work projects that if New England states do not change their RPS policies, the regional REC markets will be swamped with RECs from state-led procurement efforts. This would result in very low REC prices by the mid-2020s. However, for this analysis we assumed that New England states would increase their RPS policies in a way equivalent to Massachusetts changing its RPS to rise at 2 percent per year instead of 1 percent per year.[27] Based on Synapse's recent work on the Massachusetts RPS, we understand that over time this policy change would result in REC prices roughly equivalent to prices that

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[24] "An Analysis of the Massachusetts Renewable Portfolio Standard" available at http://www.synapse-energy.com/sites/default/files/Analysis-MA-RPS-17-004.pdf.

[25] Such behavior could come from respondents who are selected through NYSERDA's process being those who have either lower costs than average or a more bullish outlook on future energy revenues.

[26] "An Analysis of the Massachusetts Renewable Portfolio Standard" available at http://www.synapse-energy.com/sites/default/files/Analysis-MA-RPS-17-004.pdf. Confidentiality commitments prevent us from using the exact model outputs from this report.

[27] If no New England state changes its RPS policies and Class I REC prices fall and stay low in the early 2020s, the policy options considered in this report will attract greater interest from New England resources. For policy options 1 through 4, this would mean both increased cost and increased benefit for New York. For policy option 5, it would mean the same benefit with lower cost. This scenario would not impact the Base Case or DPS Staff Proposal cases.

stay level in real terms at the level projected for 2021 in that report ($17.25 in 2015 dollars). Figure 12 shows the resulting REC price forecast in nominal dollars.

Figure 12: New England Class I REC price forecast