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December 4, 2020

Ms. Samantha Meserve
Deputy Director, Renewable and Alternative Energy Division
Massachusetts Department of Energy Resources
100 Cambridge Street, 10th Floor
Boston, MA

Subject: Next Grid Markets Comments on APS

Dear Ms. Meserve,

The purpose of this letter is for Next Grid Markets (Next Grid) to provide comments on the Alternative Energy Portfolio Standard (APS) review being conducted by the Massachusetts Department of Energy Resources (DOER). These comments pertain to both the Daymark study, as well as the questions put forth by the DOER.

We appreciate the opportunity to provide input during this important process. Since its inception, the APS has been extremely successful in helping to promote a number of technologies that enhance resiliency, decrease GHG emissions and reduce utility expenses. We applaud and appreciate the Commonwealth's commitment to a cleaner, more innovative future and look forward to engaging with the DOER in shaping how the APS can play a role in making that future become a reality.

With that being said, we believe it is imperative that the DOER take action to address the oversupply / price suppression issue as soon as possible, not just for CHP but for all technologies in the program. This program plays an important role in helping to make alternative energy projects a reality, and historically low prices obviously don't support those goals. In addition, we urge the DOER to recognize the benefits of CHP and continue to support CHP's inclusion in the program. The Daymark study did an extremely poor job of representing the economic, GHG reduction, and resiliency realities of CHP, and the benefits these projects provide.

BACKGROUND

Next Grid is a Massachusetts-based company focused on developing and optimizing distributed generation assets, predominately in Massachusetts. Next Grid is uniquely qualified to provide comments on the APS due to fact that Next Grid has worked, and continues to work, with numerous CHP, heat pump, energy from waste, and biodiesel clients to successfully qualify, verify and monetize their energy credits, and is the Commonwealth's leading marketer of renewable and alternative energy credits, managing hundreds of thousands of Alternative Energy Portfolio Standard (APS) and Renewable Energy Portfolio Standard (RPS) certificates per year. Next Grid also holds the MA statewide contract for alternative and renewable energy certificate services with the Division of Capital Asset Management and Maintenance (DCAMM).

In addition to its role monetizing APS credits, the Next Grid team has been instrumental in developing over $100 million worth of cogeneration projects in Massachusetts, including the recent development of the below projects. Next Grid helps to lead and coordinate CHP projects from the very beginning; to take the projects from initial feasibility assessment all the way through engineering, procurement, construction, start-up, commissioning, and operation. Our role also includes helping to negotiate EPC contracts and Long-Term Service Agreements with the major equipment providers.

Paper Mill in Western MA – 5.5 MW Solar Turbines gas turbine, 50,000 lbs/hr HRSG. Began commercial operation in December 2015.

Paper Mill in North Central MA – 3.5 MW Solar Turbines gas turbine, 50,000 lbs/hr HRSG. Began commercial operation in January 2016.

Hospital in Worcester MA – 2.7 MW reciprocating gas engine, with heat recovery & absorption chiller. Began commercial operation in October 2018.

Hospital in Leominster MA – 2 MW reciprocating gas engine, with heat recovery & absorption chiller. Began commercial operation in June 2018.

Semiconductor plant in Middlesex County MA – Development of 2.6 MW Jenbacher reciprocating engine, hot water chiller, and 630 kW/1500 kWh battery storage. Currently in design and construction.

Manufacturing plant in Worcester MA – Development of a 4.6 MW gas turbine and HRSG. Currently in design and construction.

In the next sections we provide comments on the Daymark study, followed by specific responses to the DOER stakeholder questions posed.

COMMENTS

Comment #1 – The Daymark CHP economic assumptions dramatically understate the costs to build and operate a CHP project in Massachusetts

The Daymark study suggests that CHP projects do not need Alternative Energy Credits (AECs) to be economically viable. This is false. Daymark provided very little information as to the assumptions that led them to that conclusion. For example, Daymark did not provide their assumptions on electric and natural gas costs. They did state the assumed tariffs, but these costs make up a relatively small percentage of the overall bill, and they tariffs that were not applicable for CHP projects of that size.

To the extent that Daymark did provide assumptions (in Table 17), they were inconsistent with the reality we have experienced in being involved with more than 40 CHP projects in Massachusetts.

Large System

Assumption	Daymark	Actual (Based on Current Projects)
Installed Cost ($/kW)	$2,028	$3,500 - $5,000
Fixed O&M ($/kW-year)	$8	$120+
ITC	10%	Does not apply to non-profits

In terms of Installed Cost, $2028/kW may be sufficient to cover the cost of the equipment, but not the engineering, labor, construction, permitting, start-up, or installation. The true cost is ~2 – 3 times the cost of the equipment, or about $3,500 - $5,000 per kW installed.

In terms of O&M costs, we have helped negotiate Long-Term Service Agreement (LTSA) costs for seven CHP system in Massachusetts. For a 3326kW reciprocating engine, just the LTSA with the equipment provider would be at least $50 per Operating Hour. If you assume 92% uptime (8059 hours per year), this equates to more than $400,000 per year, or $121 per kW-year. This does not include natural gas, urea, labor, costs to maintain other equipment like the control systems, boilers, chillers, etc., which would obviously add to the overall costs. For reciprocating engines, we normally assume *all-in* O&M costs of at least $.025/kWh generated (not including labor to operate the plant). If you assume a 3326 kW engine operates 92% of the time, this equates to just under 27M kWh per year, or ~$670,000 per year in operating costs, or about $201/kW-year.

It is also worth noting that the federal Investment Tax Credit (ITC) only applies to for-profit entities. While certainly some CHP projects have been developed by for-profit companies, the majority are non-profits, such as hospitals, universities, municipalities, and state agencies. In these cases, the ITC does not apply.

In short, Daymark provided very little information as to their economic assumptions, and the information they did provide demonstrates a fundamental lack of understanding of the costs to build and operate a CHP system. Based on true economics, the APS is critical to making these projects possible; based on our experience, it is an important revenue stream that often puts a project over the top from an approval standpoint.

Comment #2 – Greenhouse Gas Reductions

CHP plays an important role in reducing Greenhouse Gas emissions. The below table[1] represents CO2 emissions in ISO NE from 2018, the most recent year for which there is a report.

2017 and 2018 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

LMU Marginal Emission Rates					
	Time-Weighted			Load-Weighted	
	2017 Annual Rate	2018 Annual Rate	Percent Change 2017 to 2018	2018 Annual Rate	2018 Load-Weighted vs. 2018 Time-Weighted
	(lbs/MWh)	(lbs/MWh)	(%)	(lbs/MWh)	(%)
All LMUs					
NO_X	0.15	0.17	13.3	0.20	17.6
SO_2	0.08	0.11	37.5	0.13	18.2
CO_2	654	655	0.2	745	13.7
Emitting LMUs					
NO_X	0.23	0.28	21.7	0.27	-3.6
SO_2	0.12	0.17	41.7	0.16	-5.9
CO_2	971	1,005	3.5	971	-3.4

The emissions rate that Daymark used ("All LMUs" 2017 Annual Rate- 654 lbs CO2 per MWh) does not accurately reflect the emissions that CHP displaces. According to the ISO 2018 Air Emissions Report, the "All LMUs" included resources that were transmission constrained. See the below from the ISO report (p 19):

> *In 2018, as in 2017, wind often displaced gas as the price-setting fuel. However, wind predominantly set price in small, local export-constrained areas of the system, as opposed to setting price for large parts of the system. Though wind was marginal 16% of the time in 2018, it was generally marginal in a very local congested area and did not directly impact system price. At the system level, wind was the marginal fuel type approximately 1% of the time.*

The more representative number at the system level is 1,005 lbs CO2 per MWh, which is the ISO Report's 2018 number for "Emitting LMUs". If the emission reduction calculation is based on "Emitting LMUs",

[1] 2018 ISO New England Electric Generator Air Emissions Report, Table 1-2; https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf

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then an efficient CHP system results in lower GHG emissions. Our belief that CHP displaces emitting resources the great majority of the time is bolstered by the following EPA report on CHP (p 29)[1]:

> *Because the CHP capacity operates continuously (or near continuously), the load duration curve shifts downward. The additional CHP capacity displaces an equal amount of generation each hour that it runs, shifting the load curve down while it runs. The CHP system therefore displaces power from the last unit of generation that would have been dispatched in each of these hours. Generators with a lower dispatch order, such as nuclear, hydro, and certain renewables, are unaffected. These resources operate whenever they are available so are unaffected by changes in power demand that result from CHP additions.*

Daymark also used a lifecycle emissions rate for natural gas, but did not appear to use a lifecycle rate for electricity. This is therefore an apples and oranges comparison. The published EPA emissions rate (CO2 factor) for natural gas is ~117 lbs CO2/MMBtu[2]. If this is used as the natural gas emissions rate, then a CHP's effective electric emissions rate is estimated to be 550 - 750 lbs CO2 per MWh[3], which represents a 25% - 45% savings compared to the emissions that CHP displaces.

It is also important to note that the Carbon Intensity (CI) of the grid at the system level is not static, but rather dynamic; it is always changing. This information is available from the ISO on a real time basis and has also been modeled by our partner, Icetec Energy Services, for a common client of ours.

The DOER could therefore structure CHP's participation in the APS based on whether the CHP system is contributing to lowering GHG emissions. In other words, the DOER could provide a "carbon signal" and the CHP system could respond to that signal.

The technology exists to not only track this data, but respond to it in real time. In the case of our common client with Icetec Energy Services, the client is responding to that signal by lowering CHP output at the times when the CI of the grid is lower than the CHP. And, when the CHP system's CI is lower than the grid, it maximizes CHP output, therefore resulting in a significant reduction in GHG reductions.

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[1] Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems https://www.epa.gov/sites/production/files/2015-07/documents/fuel_and_carbon_dioxide_emissions_savings_calculation_methodology_for_combined_heat_and_power_systems.pdf

[2] Emission Factors from EPA Greenhouse Gases Inventories, 26 March 2020; Table 1, https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf; Electronic Code of Federal Regulations Default CO2 Emissions factors and High Heat Values for Various Fuel Types; https://www.ecfr.gov/cgi-bin/text-idx?SID=d7605b0c56cb1513877be74469c5ad19&mc=true&node=ap40.23.98_138.1&rgn=div9

[3] The range depends on technology (reciprocating engine vs. gas turbine) and efficiency (thermal utilization).

Comment #3 – CHP Projects Provide Resiliency Benefits

It is important to note that CHP projects are located at facilities that need 1) resiliency and 2) high temperature hot water or steam. These include hospitals, research institutions, and critical manufacturing. In these cases, the CHP system provides islanding capabilities so that the CHP system can continue to provide electricity and steam in the event of a grid outage. In addition, these locations need steam, which are better served from CHP systems.

These comments are not meant to denigrate the importance of heat pumps and other renewable thermal technologies. We have a number of clients that utilize these technologies and we fully support their development, implementation, and participation in the APS. Rather, we think there is a time and place for those technologies, and highly critical facilities that use steam and need to island cannot reasonably rely on grid-connected renewable thermal technologies.

Additionally, CHP projects often help to facilitate microgrid and alternative/renewable projects that might not otherwise be pursued due to a facility's economic goals. For instance, of the new projects that we are working on, two-thirds are incorporating battery storage.

Comment #4 – To promote biogas, Massachusetts should not require physical delivery and should allow and promote long-term contracts with Natural Gas Local Distribution Companies

The Daymark study encouraged the use of biogas (a.k.a., Renewable Natural Gas). We agree that increased biogas utilization would be beneficial but there is a limited supply of biogas, particularly in New England. To the degree that biogas is being generated and injected to a pipeline, it is likely to go to more valuable markets like the California Low Carbon Fuel Standard (LCFS) and/or the federal Renewable Fuel Standard (RFS). Neither the LCFS nor the RFS require physical delivery. In other words, a user in California can enter into a contract with a digester in, for example, Ohio, inject the biogas into the pipeline, and be eligible for the LCFS and RFS credits without having to physically deliver that biogas to California.

If Massachusetts were to change its rules and not require physical delivery, and if the Commonwealth allowed the utilities to enter into long term contracts for biogas (similar to the Section 83A provision that allows for long term contracts for wind), it could compete with other markets on the basis of participation in the RPS, APS, Clean Peak Energy Standard, and long-term contracting. Without these changes, biogas will continue to flow to other, more valuable, markets, like the LCFS and RFS.

STAKEHOLDER QUESTIONS

Next Grid provides the following comments to questions posted by the Department of Energy Resources.

Questions 5 and 6: Is the current APS minimum standard and the annual rate of increase adequate? Please include details and any data supporting why or why not, where possible. Do you anticipate a growth or decline in the supply of AECs in the APS program over the next 5 years? 10 years? If so, how would you quantify this increase in growth rate? Please include details and any data supporting your conclusions.

It is clear that the current market is significantly over-supplied and the Obligation needs to be increased. The Daymark study accurately reflected that. In terms of the growth of supply, we do believe that the Daymark study over-stated the future contribution of CHP. As the DOER is aware, there is a large project coming online at the end of 2020 that will significantly add to supply. Other than that, most large “Meds and Eds” (i.e., hospitals and educational institutions) that are capable of installing CHP, have done so. The low hanging fruit in the manufacturing sector, which usually relates to thermal availability, has also largely installed CHP. This isn’t to say that there won’t be more CHP installed; there will be. However, we believe that the Daymark assumptions on future CHP generation were over-stated.

Question 7: Are there modifications to the APS program that could be made to reduce the volatility of the APS market?

Mechanisms that respond to market conditions, such as increasing the obligation the following year if supply is greater than demand, could aid in reducing volatility of the market. We don’t believe that the DOER needs to recreate the wheel as the Department has already created mechanisms that address volatility. For example, the Clean Peak Energy Standard’s obligation self-corrects based on generation. This would be useful in applying to the APS. In addition to a responsive mechanism like CPS, creating a floor price for AECs, could also provide some longer-term certainty for project investment decisions. If the project owner thinks the program is here to stay, developers can better encourage moving the project forward.

Question 10: Are there currently eligibility criteria in the APS program that you believe are a barrier to participation in the program? How would you address these barriers?

The APS currently only allows for renewable heating, and not cooling, to be counted toward APS certificates. Additionally, intermediate and large renewable thermal systems require some form of direct or indirect metering to calculate useful thermal. Next Grid has reviewed numerous private, municipal, state and university renewable thermal projects, and is in the midst of applying for multiple intermediate/large heat pump projects. Based on experience with commercial-sized projects, particularly for heat pumps systems (air source and ground source), these requirements raise costs and create complexity, therefore constructing a high hurdle in terms of program participation.

Often these projects have equipment that simultaneously heat and cool. Having to meter and calculate these potential scenarios can be complicated. Allowing for cooling as eligible would eliminate this issue.

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At a minimum, allowing for instances of simultaneous heating and cooling without having to create complicated methodologies would be a benefit. Alternatively, if DOER created standard assumptions (rather than metering) to account for simultaneous heating and cooling for heat pump projects, it could reduce complexity and streamline program applications. We recognize that DOER has been instrumental working with these projects and developing methodologies within the current program confines that assist with program entrance, but it would be useful to have updates that provide more overarching metering simplicity.

Due to aforementioned factors, and unless a site is designing for the program specifically in mind at the onset of a project, then we have found it can be difficult and often expensive to meet current program requirements. Additionally, there can be a disincentive for sites that are more efficient (but not Passive House, "Zero Energy", or HERS rated which can receive a multiplier), as they potentially generate less credits because they efficiently heat a space and have a low designed EUI. These sites' projects are still expensive, but do not necessarily benefit from significant APS potential revenue.

Some further specific issues and suggestions for addressing barriers for APS projects are:

- Relaxing ANSI C12.20 standards for kW meters for renewable thermal projects, or to allow for metering points within the equipment itself. Revenue-grade kW metering is required on grid electric for intermediate/large projects. Revenue grade metering for often numerous heat pumps can be cost prohibitive, but there are still accurate metering alternatives that are not necessarily "revenue-grade."
- If DOER can provide a public list of BTU compliant and affordable meters it would aid in program entrance. BTU meters can also be expensive.
    - For instance, allowing EN1434 BTU flow meters, a European Standard, to be used may be a cost-efficient and still accurate alternative.
- Based on past DOER guidance, insertion type flow meters have not been allowed for the program. It would be useful to have clarification if this is still the case. If so, a suggestion is to allow insertion flow meters as it can avoid purchasing the common alternative of more costly flange type meters.
- Increase the intermediate metering threshold (which is capped at 1 MMBTU/hr for heat pumps) to capture a larger portion of commercial buildings. Based on current guidelines, this would allow more sites to use kW metering for estimating thermal rather than more costly BTU meters in addition to kW meters.
- With respect to VRF air and ground source systems, a suggestion is to simplify the calculations by measuring/calculating the net amount of heat being sent to the building via the outdoor unit, instead of individually monitoring terminal unit loads, which can provide increased data management and complexity.
- Add multipliers for efficient projects (ex. EUIs under a baseline) that may not necessarily be Zero Energy or Passive House.

To summarize for commercial-sized projects, the cost of complying with some of the metering requirements compared to projected APS generation can prevent program entrance, and for sites considering investing in these new technologies, provide less of an incentive to pursue a project (**DOER Question 8**).

Question 11: What revisions to the existing APS eligibility criteria would you propose to improve and simplify the APS program, if any?

Please see the above response to Question 10, namely allowing for cooling and relaxing metering requirements.

We appreciate the opportunity to provide these comments and are available should you have any questions.

Best regards,

Matthew Wolfe
Managing Partner, Next Grid Markets, LLC