May 21, 2021

Mark D. Marini, Secretary
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D.P.U. 20-75

Pope Energy Reply Comments – Second Set of Information Requests of the Department of Public Utilities to Non-EDC Participants This Proceeding D.P.U. 20-75

Submitted by Doug Pope, President

Dear Secretary Marini:

We continue to be appreciative of the Department's engagement in investigative proceedings involving non-EDC participants in dockets that otherwise would be litigated proceedings excluding direct participation of stakeholders such as ourselves who are needed to execute the yet-to-be finalized 2025 and 2030 Clean Energy Climate Goals.

Requests:

Stakeholders-2-1
Refer to National Grid's response to EDC-1, at 8-9. Please provide your perspective on National Grid's proposal to allocate up to 40 percent of the DG interconnection costs as system benefits to all customers.

Enabling DG as Opposed to Constraining DG:

The old and existing cost causation model is "if you break it, you fix it," or if a developer proposes a project that causes cost disruption from the status quo, the developer of that disruptive asset pays for such cost. The National Grid proposal that 60% of all cost to upgrade the grid to the CECP 2030 and 2050 Decarbonization Roadmap requirements will be borne by solar and other DG is a continuation of that old cost causation model.

The Global Warming Solutions Act of 2008 (GWSA) and *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy*, just signed into law by Governor Baker in 2021, charges EOEEA to create and enable renewable generation and reductions in the building and transportation sectors to 85% net zero from 1990 levels by 2050 with 50% of that total being accomplished by 2030. Through the Secretariat, the legislature has charged the Department to enable solar and other DG to meet the climate and emission reductions goals. Enabling means that the process to commercial operation for the emission reductions technology needs to be economic. In the case before the Department, interconnection to the grid needs to be enabled to be timely, dependable and economic; otherwise, the Interim 2030 CECP as written and 2050 Next Generation Roadmap goals will not be met.

The National Grid proposal that charges 60% of all grid upgrades to distributed generation is not based upon data that looks forward to the emission obligations set by the legislature. All of National Grid's proposals have been based upon static conditions using completed applications as the basis of all responses. The 60% proposal is just that – a proposal, a guess, a compromise – but is it based only upon the cost distributed generation assets or is it based upon transmission assets as well?

The Energy Pathways to Deep Decarbonization[1] conducted by EEA states that two of the four pillars of decarbonization are the "98%+ reduction in the carbon intensity of electricity production" and the "3.5x increase in the share of final energy delivered by electricity." Having read the 2050 Decarbonization Roadmap, National Grid somehow asserts that only 40% of the cost to upgrade the grid should be borne by ratepayers? Please see Exhibit 1 attached.

Does the National Grid 40% proposal differentiate between feeder and substation improvements that will be required to accommodate 750,000 EVs and 1,000,000 heat pumps by 2030? Does the National Grid assignment of 60% of the cost to upgrade the grid to DG interconnections include the doubling or tripling of final energy supplied buy electricity to meet 2050 Roadmap goals? No, solar PV + storage and other DG are being penalized as a first movers not enabled as an emission reduction resources.

The only data that exist is the Cost_Data_Entry_040416, Sustainable Energy Advantage as part of a consulting engagement with DOER that was conducted in the feasibility study to establish a tariff for the SMART program. The data below was considered part of the economic feasibility to enable a starting point for the SMART program.

Interconnection Costs ($/W DC)

Interconnection costs include costs relating to connecting to the grid, such as construction of transmission lines, permitting costs with the utility, and start-up costs. This category will also include the cost of a new substation, if necessary.

For each of the project size/type categories below, we provide our initial estimate ("SEA Starting Point") of the typical MA interconnection costs per Watt DC as a reference. Please provide your typical range of costs for each bin by filling in the "Low End of Range" and "High End of Range." For bins which you cannot provide cost data, please write "N/A."

Project Type Assumptions: ***Brownfield/Landfill:*** *Assume projects < 250 kW would be Rooftop Solar.*

MA Interconnection Costs - $/W DC (2015-2016)

Project Type	<25 kW			25-250 kW			250 kW-1 MW			>1 MW			Range (Low to High)		
	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range	SEA Starting Point	Low End of Range	High End of Range
Ground-Mount Solar	N/A	NA	NA	N/A	$0.13	$0.25	$0.11	$0.13	$0.25	$0.11	$0.18	$0.25	**$0.11 - $0.11**	**$0.13 - $0.18**	**$0.25 - $0.25**
Brownfield Solar	N/A	NA	NA	N/A	NA	NA	$0.11	NA	NA	$0.11	NA	NA	**$0.11 - $0.11**	**$0.00 - $0.00**	**$0.00 - $0.00**
Community Shared Solar	N/A	NA	NA	N/A	$0.13	$0.25	$0.11	0.13	0.25	$0.11	0.18	0.25	**$0.11 - $0.11**	**$0.13 - $0.18**	**$0.25 - $0.25**
Landfill Solar	N/A	NA	NA	N/A	$0.13	$0.25	$0.11	$0.13	$0.25	$0.11	$0.18	$0.25	**$0.11 - $0.11**	**$0.13 - $0.18**	**$0.25 - $0.25**
Solar Canopy	N/A	NA	NA	$0.17	0.13	0.25	$0.11	$0.13	$0.25	$0.11	$0.18	$0.25	**$0.11 - $0.17**	**$0.13 - $0.18**	**$0.25 - $0.25**
Rooftop Solar	$0.00	NA	NA	$0.17	$0.13	$0.25	$0.11	$0.13	$0.25	$0.11	0.18	0.25	**$0.00 - $0.17**	**$0.13 - $0.18**	**$0.25 - $0.25**
Low Income Solar	$0.00	NA	NA	$0.17	0.13	0.25	$0.11	0.13	0.25	$0.11	0.18	0.25	**$0.00 - $0.17**	**$0.13 - $0.18**	**$0.25 - $0.25**

[1] Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, December 2020, Figure ES1, Page 2

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As indicated in our comment letter of April 13, 2021, we agree with National Grid's findings in their response to EDC-3 Page 2 of 3 that states that the average interconnection fee is between $133/kW and $226/kW.

National Grid's findings in this instance validate both the reality on the ground and the efficacy of solar policy that has enabled solar PV for the commercial operation as an emission reduction resource.

Accordingly, consistent with our advocacy in comment letters in D.P.U. 19-55 and D.P.U. 20-75 for project differentiation we propose the following interconnection fee including point of common coupling cost where the fee is cumulative based on total AC capacity size.

- 5 cents/watt for the first 60 kW AC
- 15 cents/watt for the capacity over 60 and up to 500 kW AC
- 20 cents/watt for the capacity over 500 and up to 1 MW AC
- 21 cents/watt for the capacity over 1 MW and up to 2 MW AC
- 22 cents/watt for the capacity over 2 MW and up to 3 MW AC
- 23 cents/watt for the capacity over 3 MW and up to 4 MW AC
- 24 cents/watt for the capacity over 4 MW and up to 5 MW AC

On May 13, 2021 at 5:39 PM, EEA Secretary Kathleen Theoharides sent an email to all 2030 CECP Commentors and Stakeholders stating that EEA, in accordance with the requirements of *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (2021), the emission limits, sublimits, and carbon sequestration baseline and goals will be finalized by July 1, 2022. Given that D.P.U. 19-55 intended to expedite a decision-making process relative to interconnection to keep solar projects from falling out of the queue and that the Department and all stakeholders have to wait another 13 months for policy direction from EEA, the Department should adopt the above interconnection fee schedule, without an adjudication process, as an interim measure until EEA provides 2025 and 2030 CECP policy direction. Upon issuance of the 2025 and 2030 CECP, which will have the force of law[2], the Department will be in a better position to evaluate the impacts of the pathways to a 50% reduction from 1990 emissions levels by 2030.

The interconnection of solar has costs, and those costs have been captured by National Grid data collection of the average cost of interconnection mentioned above and the SMART investigation conducted by SEA on behalf of DOER; the ratepayer advocate has ample evidence that the ratepayer interest are reasonably protected by the application of these fees for interconnection of solar and other DG emission reduction resources.

It is our assertion that the Department will continue to struggle to find a scientific apportionment of cost for solar and other DG, beyond the table of interconnection cost listed above, due to the aggressive 50% reduction of emissions by 2030 demanded by the legislature and concurrent beneficiaries in the transportation, building and renewable generation sectors.

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[2] EEA Presentation 2050 Roadmap Building Solutions to Address Climate Change in the Commonwealth, April 1, 2020 siting Kane vs. DEP, Page 5

In the public forum of the TSRG, on May 20, 2021, on a RingCentral meeting, the difficulty in establishing a scientific basis for apportionment of cost was described by the Shahir-Eversource comment in the chat at 03:37 PM. “Distribution System is so dynamic that it is extremely difficult to match exactly what you see in the Software.” So, modeling of coincident emission reduction beneficiaries will be nearly impossible; hence the assignment of reasonable cost on a $/kW basis.

The policy that the Department should establish is that solar PV and other DG are assigned a reasonable cost of $/kW to interconnect, and all other DG and transmission cost are rate-based on a 40-year amortization schedule. The substation-to-substation infrastructure and supporting transmission system should be installed based upon the emissions reduction requirements for the next twenty years. Amortizing those cost over 40 years will not unnecessarily burden ratepayers for requirements that exist in current legislation and will need to be installed anyway. We continue to assert that these improvements should be financed with tax-exempt debt, particularly with today’s low rates. Illustratively, an AA-Rated Muni Bond for 30 years is 1.75% versus the 3% or higher offered by the EDCs.

Stakeholders-2-2

Refer to Stakeholder responses to Stakeholder-4, which include recommendations for a 30- to 45-day Department review of an EDC’s provisional system planning program proposal. Refer to (a) G.L. c. 30A, §§ 1(1), 10, 11, 12; and (b) 220 CMR 1.00. Considering the interests and issues involved in the review of an EDC’s provisional system planning program proposal, the Department may be required to conduct the reviews of these proposals through an adjudicatory proceeding, which includes notice, intervention, discovery on petitioner’s filing, opportunity for intervenors to file direct cases, discovery on intervenors’ cases, opportunity to present rebuttal testimony, evidentiary hearings, briefs (initial and reply). Assume you are a party to an adjudicatory proceeding to review an EDC’s provisional system planning program proposal, identify the time period you would request for each of these procedural steps.

Given the 13-month delay in EEA 2025 and 2030 CECP emission reduction obligations decision, the existing SMART program obligations, the information available from the Interim 2030 CECP and 2050 Decarbonization Roadmap and attendant technical reports, the question should be: is the Department prepared to make emergency determinations until a larger emissions reduction framework is established by EEA?

If the Department established the DG interconnection cost as listed above on an emergency basis and instructed the EDCs to issue Early ISAs capable of satisfying the SOQ requirements in SMART and then issuing final ISAs 12 months prior to a potential commercial operations date, the goals of retaining solar projects in the queue would be achieved. For circuits and substations that have a lead time of over 3 years, the solar developer today most likely would not be the same developer that would take the project to commercial operation in 3 to 5 years, but the ISA would have value and be capable of being sold to developers who will finish the projects.

The next question is, in the absence of direction from EEA, using the Brattle Group report of September 2019, is the Department to use the next 13 months to direct the

EDCs to study the cost of upgrading the substation to substation infrastructure and attendant transmission system that will be required for the next twenty years?

We support the Department's 30- to 45-day review of EDC's provisional planning system. The EDCs increasingly recognize the larger emission reduction obligations enacted by the legislature; however, the EDCs continue to assert that their planning is based upon completed applications. Why would the Department engage in an adjudicated proceeding that is meaningless in light of the near-term obligations in front of Massachusetts?

Stakeholders-2-3
Refer to your response to Stakeholders-2-2. Explain how such a process would affect your decision to move forward with your DG project.
a) Provide a response based on an adjudicatory proceeding timeline of 3 months;
b) Provide a response based on an adjudicatory proceeding timeline of 6 months; and
c) Provide a response based on an adjudicatory proceeding timeline of 9 months.

A. For companies who build greater than 10 kW and less than 500 kW size solar systems and who need work to retain staff, a 3 month plus 45-day review by the Department may be too long.
B. Our firm would prefer a 4.5-month adjudicated process plus a 45-day review by the Department, totaling 6 months as a reasonable time frame.
C. Nine months plus a 45-day review period by the Department represents the same choppy solar policy that has plagued an otherwise well-managed solar program. It will most likely be made meaningless by the publication of the 2025 and 2030 CECP by EEA on July 1, 2022.

We appreciate the fact that the Department has previously said it was not prepared to entertain the larger rate basing of required infrastructure improvements. The Act passed by the legislature this year has advanced the rate-basing issue front and center in a fashion that substantial progress will not be made without addressing the issue affirmatively.

Best Regards,

Doug Pope
President

Exhibit 1

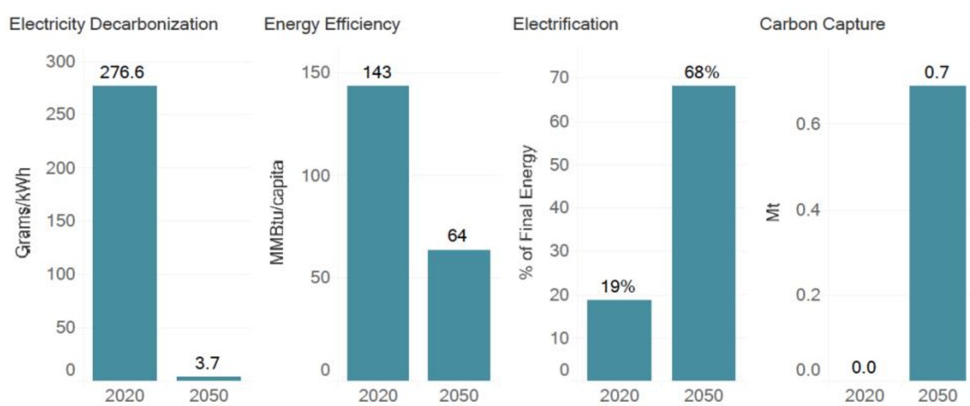
EEA Presentation 2050 Roadmap Building Solutions to Address Climate Change in the Commonwealth, April 1, 2020 siting Kane vs. DEP, Page 5

and the more flexible the end-uses in terms of their time of use, the more competitive electrification is relative to using decarbonized fuels.

- **Decarbonizing electricity** – As the main form of energy consumed, electricity is the foundation of a decarbonized energy system. For total energy system emissions to reach the target, the carbon intensity of electricity must reach nearly zero.
- **Using carbon capture technology** – Not all end uses can or will be electrified, therefore some fuels are required. Carbon capture is an integral part of managing fuel use in a net-zero energy system, applied to the production of net-zero fuels and/or to capturing emissions from fuel combustion.[1]

These basic strategies— "the pillars of decarbonization"— have been identified in previous pathways studies, in the U.S. and internationally. The key metrics for each pillar in Massachusetts are shown in Figure ES1, which contrasts the Net Zero system in 2050 to today's system.

Figure ES1. Four pillars of decarbonization for the All Options pathway. Key metrics include a 98%+ reduction in the carbon intensity of electricity production, a 55% reduction in per capita energy consumption, a 3.5x increase in the share of final energy delivered by electricity, and captured carbon within Massachusetts of 0.7 MMt.



The modeling included a number of assumptions that increase the realism and comparability of these results. No behavior change was assumed that would decrease the demand for "energy services" such as driving, flying, heating, and manufacturing. Consequently, these results demonstrate that the Net Zero target was achievable even while meeting the latest U.S. government projections of long-term energy service demand. All technologies used are either already commercially available or have been demonstrated at a large pilot scale. There was no early retirement of end use equipment before the end of its economic lifetime. Finally, a number

[1] Carbon capture is a pillar of decarbonization that is applied in all pathways, including the 100% primary renewable energy pathway in which captured carbon is needed for producing renewable fuels. However, carbon capture and storage (CCS), in which the captured carbon is geologically sequestered, is not; CCS is used in only one pathway, in which the sequestration occurs out-of-state. Most carbon capture opportunities are also outside Massachusetts, in states better suited for the production of net-zero fuels; in theory all carbon capture could occur out-of-state. However, since carbon capture is essential to a net-zero energy system regardless of physical location, it is included here as a pillar of decarbonization. In these pathways, bio-asphalt is a form of carbon sequestration employed in Massachusetts, but it does not involve carbon capture.

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