April 8, 2021

**By Electronic Mail**

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

**Re: Response to the First Set of Information Requests of the Department of Public Utilities to the D.P.U. 20-75 Electronic Distribution List**

Dear Secretary Marini,

On behalf of BlueHub Capital Inc. ("BlueHub Capital" f/k/a Boston Community Capital), please accept the following responses for filing in the above referenced proceeding.

BlueHub Capital is a thirty-five-year-old community development finance institution dedicated to building healthy communities where low-income people live and work. Since 2008, we have worked through our affiliate, BlueHub Energy, to develop innovative financing and business models to expand access to solar in low-income communities. We have developed and operate approximately 7 MW of solar capacity across 80 Massachusetts projects. These projects primarily serve affordable, multifamily housing developments. We also have projects that benefit non-profit organizations and municipal facilities, such as the Greater Boston Food Bank. Our experience developing solar for low-income beneficiaries means we are uniquely positioned to understand the challenges of serving this market segment and the ways in which policy design can enable or hinder a more equitable distribution of solar's direct benefits across all ratepayer classes.

Thank you for your consideration.


DeWitt Jones
BlueHub Energy
djones@bluehubcapital.org
617-427-3580

Fred Unger
Heartwood Group, Inc.
unger@hrtwd.com
508-951-7419


Enclosures

cc: Kate Zilgme, Hearing Officer
dpu.efiling @state.ma.us

Information Request Stakeholder-1

Refer to the response to EDC-1. Do you currently have a distributed generation facility in the interconnection queue within one of the groups identified by the EDCs?

Response

No. From December 2017 until March 12, 2021, we had a model[1] project in the interconnection queue. This project was included in the October 2020 National Grid Gardner Area Detailed Impact Study that concluded in September 2020. Based on the cost results of that study and the capacity of other projects remaining in the queue, our upfront cost allocation would have required us to pay an estimated $2.9 million per megawatt (MW) in distribution and transmission system upgrades, plus any cost overruns, plus an additional $1.7 million per MW over 20 years in recently proposed transmission system "carrying costs. We would also need to wait to interconnect until at least 2027 to allow for the completion of separate transmission upgrades. Our response to Information Request Stakeholder-2 provides a detailed description of the project's costs under this group study. We further note that under the current cost allocation process, we would have been required to pay 100% of the upgrade costs within the first year of signing an Interconnection Service Agreement and we would be responsible for any increased costs in the event other projects in the queue dropped out. This made the project economically infeasible.

As a result, our project, as well as similarly impacted projects, opted not to proceed with that process but were invited by National Grid to participate in a subsequent group study. We decided not to move forward with the most recent round of group study and are waiting until there is clarity around any new policy for cost allocation for interconnection costs and a more reasonable payment schedules for interconnection upgrades with excessively long lead times. We expect to re-apply for interconnection after the outcomes of D.P.U. 20-75 are clear. In the meantime, we are maintaining all permits and site control for the project.

[1] Our project hit all the stated goals of Massachusetts' solar energy policy: serving low-income communities; developing brownfield sites; minimizing any adverse impacts on neighbors, viewsheds, and communities; utilizing storage to maximize benefits to the overall electric system; and reducing climate impacts. It is on a long-vacant, industrial-zoned brownfield site and will be completely hidden from view from any road and any neighbors. This project is fully permitted and has been ready for construction since January 2019.

Information Request Stakeholder-2

Refer to the response to EDC-1. Based on the high-level planning estimates for costs and timelines provided by the EDCs, would you move forward with interconnection under the currently applied cost causation methodology?

Response

No, we would not move forward with interconnection under the currently-applied cost causation methodology. We also do not expect that any other project would be able to move forward based on the cost estimates in the October 2020 Gardner Area Detailed Impact Study and the currently applied cost allocation methodology.

Based on the results of the above study and subsequent discussions with National Grid representatives, our understanding is that we would be expected to pay a proportionate share of $43 million in transmission upgrades, $29 million in distribution upgrades, and $2.24 million in annual transmission carrying costs to support new generation capacity well beyond what is in the queue. However, the upfront cost requirement for any individual project is based on that project's proportionate share of the capacity currently in the queue. As a result, while a project may be feasible supporting their proportionate costs based on the total capacity of the upgrades, costs based on the active capacity in the queue make many projects infeasible. While current projects would get refunded a portion of those upfront costs as other projects join the queue or interconnect, current projects would pay disproportionately more upfront and subject to the substantial risk that they would not receive any reimbursement in the event other projects do not ultimately interconnect.

For our 2 MWac (4.02 MWdc) solar plus storage project, the upfront costs would have been approximately $5.8 million, or $2.9 million per MW plus additional costs if other projects currently in the queue dropped, plus any cost overruns. In addition, we would be responsible for annual transmission carrying costs of 5.21% of our share of the transmission upgrade costs, or about $3.4 million ($1.7 million per MW) over 20 years. Overall, our project would be responsible for paying $9.2 million in total system upgrade and carrying costs for a 2 MWac system.

The current cost allocation creates an additional barrier based on the timing of paying for upgrade costs. We've been informed that our new project will need to wait to interconnect until at least April 2027 when an A1 B2 transmission line is completed. Current policy would require us to pay $1,450,000, 25% of the initial $5.8 million upgrade cost, upon signing the Interconnection Service Agreement and the balance just a few months later. Financing these interconnection costs until we could interconnect would require an additional $1.5 million.

With the present investigation underway, the DPU straw proposal, and EDC proposals in circulation, it makes far more sense to us to re-submit our interconnection application after completion of this proceeding rather than remain in the queue, pay additional study costs, and potentially be obligated to pay the very high upfront costs that would be required under the current cost allocation rules.

Information Request Stakeholder-3

Refer to the response to EDC-1. If a provisional system planning program were implemented that decreased the cost to interconnect but did not alter the timeline for EPS upgrade construction, would you move forward with interconnection?

Response

We have a fully permitted site that is ideal for solar deployment. It will be serving low-income communities; re-developing a brownfield site; utilizing battery storage to maximize benefits to the overall electric system; and reducing climate impacts. It is on a long-vacant, industrial-zoned site and will be completely hidden from view from the road and any residential neighbors.

We are willing to wait to interconnect and pay the necessary carrying costs to keep the lease and permits in place if there is a light at the end of the tunnel. All development needs reasonable cost allocation formulas and a fair way of paying for what is essentially public infrastructure upgrade costs that don't overburden a project with huge costs years before interconnection would be possible. In our view, if interconnection involves long lead times, the bulk of the payment for interconnection costs should not be required until the EDCs and distribution system is ready to accept it for interconnection.

Replacing and upgrading old transformers, lines, and other equipment, while certainly benefitting the distribution projects being interconnected, also benefits all other customers utilizing the impacted equipment and provides benefit to all ratepayers who would ultimately have to pay the cost of maintaining and eventually replacing that equipment even in the absence of distributed generation.

It is our hope that this proceeding will result in a more fair and sensible cost allocation formula that doesn't involve distributed generation developers paying the entire cost of upgrades far in advance of being able to interconnect their projects to the distribution system.

Information Request Stakeholder-4

Refer to the response to EDC-4, how long following submittal of a provisional system planning program proposal by the EDCs would the Department need to make a determination on the proposal for you to move forward with interconnection?

Response

EDC-4 suggests that the Department would implement a provisional system planning program based on the study results from group studies. It is our position that system planning should be done years in advance of the need for any major upgrades and projects should not be subjected to group studies or the extremely protracted interconnection delays that many distributed generation projects are now experiencing.

It should be considered an example of the failure of the utility planning system that our project could apply for interconnection in December of 2017, not get any written cost guidance until October of 2020, and then have that guidance indicate that even after paying $5.8 million upfront for utility system upgrades and another $3.4 million over the life of our project to maintain those upgrades we paid for, we would be unable to interconnect our project before April 2027.

The EDCs must have an incentive to make the interconnection process work and keep costs reasonable for both distributed generation and ratepayers. Under the current system, the more the EDCs charge, the more they earn. The utility business model and regulatory models need to be fundamentally changed to a performance-based incentive system. Among many other distribution system upgrades and customer facing metrics that utilities should be heavily incentivized to deliver is a clear incentive for all three-phase lines in the Commonwealth to accommodate fully bi-directional electricity flows.

Information Request Stakeholder-5

Are there any federal law implications that should be considered concerning sharing costs of EPS upgrades with interconnecting customers over an extended period of time and in particular after the EPS upgrade has been constructed?

Response

We refer you to the comments of Handy Law submitted in D.P.U. 19-55 on April 2, 2020, which state:

> *Given FERC's exclusive jurisdiction over the "transmission of electric energy in interstate commerce," and over "all facilities for such transmission or sale of electric energy" spelled out in section 201(b) of the Federal Power Act (16 USC 824(b)), where does a State get its authority to regulate transmission system studies or upgrade costs through state tariffs?*

The submittals by Green Development, Dry Bridge Solar Companies, and the Solar Energy Industries Association in Federal Energy Regulatory Commission (FERC) Docket EL21-47 may also be valuable, as these address precisely the questions the Department is asking in this proceeding. Like these other distributed generation developers, we question the jurisdictional issues inherent in this question and especially want to highlight concerns regarding the practice of the EDCs assessing fees on behalf of financially affiliated transmission companies to be paid by independent generators.

As to the second part of the question, regarding "sharing costs of EPS upgrades with interconnecting customers over an extended period of time and in particular after the EPS upgrade has been constructed," we find it unreasonable that on top of being charged for the full cost of transmission system upgrades, the EDCs also plan to charge distributed generation a proposed "annual transmission carrying costs" of 5.21% of those transmission upgrade costs. This is a completely new charge that we were surprised to learn about with the publication of the October 2020 Gardner Area Detailed Impact Study. We are not aware of any previous examples in New England where interconnection customers where subject to such charges. Similarly, we are not aware of any other types of distribution system customers being charged this type of "carrying cost." Finally, we are also not aware of any docketed proceeding before the Department or the FERC in which such charges were reviewed and approved.