State of Rhode Island Public Utilities Commission

In Re: Petition of the Episcopal Diocese of Rhode Island for Declaratory Judgment on Transmission System Costs and Related "Affected System Operator" Studies

Docket No. 4981

Pre-Filed Testimony of

Fred Unger

May 21, 2021

Q. Please state your name and business address.

A. My name is Fred Unger. My business address is 165 Evergreen Street, Providence, RI.

Q. By whom are you employed and in what capacity?

A. I am the President of Heartwood Group, Inc.

Q. What was your professional and educational background?

A. I have a degree in Environmental Studies from Antioch College. I started Heartwood in 1983 to focus on energy efficient construction. Over the years the company has also been engaged in real estate development, energy project development and a variety of business consulting roles.

Q. What roles do you play in the energy industry?

A. These days I primarily provide consulting services coordinating the design, permitting, construction and operation of solar energy projects.

Q. How long have you been doing this work?

A. I worked on my first solar heated wind powered building in 1976. In 2003 we started one of the first companies in the country focused on remote monitoring of solar wind and fuel cell projects which we sold to a competitor in 2005. Around that time we also were providing development services for a couple land based wind energy projects. In 2008, I started providing development services for solar projects for Boston Community Capital, developing projects serving affordable housing communities and nonprofit organizations. I have provided consulting and development services for a couple financial institutions, solar construction companies, local and state agencies, land owners, universities and a municipal utility.

Q. How many solar projects been responsible for developing?

A. I have coordinated development efforts on five megawatt scale ground mount projects in Massachusetts and RI and about 80 commercial rooftop projects in Massachusetts, plus many more projects that were started but had to be abandoned due to issues with permitting or interconnection. We have also been responsible for early stage development of a couple megawatt scale wind projects.

Q. What important changes have you seen in the industry lately?

A. In general energy policy seems to be getting more complex and cumbersome and the regulatory environment is significantly slowing project development at a time that legislators and governors are establishing goals for accelerating growth of our industry. The most significant change impacting project development has been the major recent changes to the interconnection process which have increased costs and delays immensely on many large scale projects.

Q. How has the interconnection issue impacted your business?

A. Interconnection has become an extreme wild card, with costs very unpredictable and even the path to getting to known costs becoming overly costly and burdensome. The client I have developed the most projects with has decided to defer any further large scale solar development until interconnection timing and cost allocation issues are resolved. I am taking on non-solar projects again for the first time in about a decade.

Q: Share the history of your recent Kinzer Drive project in central Massachusetts.

A. From December 2017 until March 12, 2021, we had a model project in the interconnection queue. 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. We started work on the project in early 2017. Being a brownfield site, we spent significant time clarifying possible environmental liabilities before proceeding with permitting and interconnection. The project is fully permitted and has been ready for construction since January 2019, with the exception of interconnection approvals.

This 2 MWac (4.02 MWdc) solar plus storage project was included in a couple different group and area study efforts over more than three years during which time, National Grid indicated we would be connecting to three different substations. It was clear from the process that National Grid had never anticipated or planned for a time when significant levels of distributed energy resources were on the utility system. Most recently the project was included in the 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. Under the current Massachusetts 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 and pay for another subsequent group study in order to keep our interconnection queue position. 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 will re-apply for interconnection if the outcomes of Massachusetts D.P.U. 20-75 are favorable.

Q. Based on the estimates for costs and timelines provided by National Grid, would you move forward with interconnection for that project under the currently applied cost causation methodology?

A. No, we could 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 those kinds of cost estimates 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 have been informed that our project will need to wait to interconnect until at least April 2027 when a new 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 Massachusetts DPU straw proposal, and EDC proposals in circulation, we decided 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.

Q. 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?

A. 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 do not 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.

Q. How do the costs and timelines suggested for that project compare to others you have developed?

A. We have a 1 MWdc - 800 kWac project in the same city that went online in June of 2014. The total interconnection cost for that project was $265,520. In April 0f 2016 we had a 1.39 MW dc - 1MW ac project go online with an interconnection cost of $308,000. Our other projects have all come in around that same range on a per MW basis. As you can imagine, we were quite surprised when in 2018 we were told verbally that our interconnection cost for Kinzer Drive would exceed a million dollars and even more surprised when we got the results of the study in early October 2020 expecting us to pay $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” for a 2 MWac project.

Q. How have interconnection issues impacted your RI work?

A. I have been fortunate that the only project I have developed in Rhode Island is on a circuit with very little previous distributed generation. Being familiar with the emerging problems with interconnection elsewhere when we started the project three years ago, we moved aggressively to get interconnection designed and submitted to secure a place in the interconnection queue as quickly as possible. Though our project was rated at 2.87 MWdc and 2.376MWac, we had minimal distribution system upgrades and no transmission system impacts to deal with. The interconnection cost was in line with our earlier experience.

Q. What is your conclusion from such wildly varying cost estimates for interconnection?

A. The interconnection cost allocation methodology currently in place is not workable and is very unfair. System planning on the part of the utilities and the ISO has not been nearly adequate in anticipating and building capacity for the bi-directional grid of the future. Utility regulators on the state and federal level need to accelerate the buildout of a modern grid.

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 the regulators would implement 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.

System planning should be done years in advance of the need for any major upgrades and projects should never need to be subjected to group studies or the extremely protracted interconnection delays that many distributed generation projects are now experiencing.

It should be considered a clear 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 distribution companies must have an incentive to make the interconnection process work and keep costs reasonable for both distributed generators and for 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 every transmission line and every distribution line in the United States to accommodate fully bi-directional electricity flows.

Q. In the Massachusetts proceeding currently underway on these issues (DPU 20-75) the commission asked: 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? Is this an issue we should be considering in Rhode Island?

A. I am not an attorney, but it seems there is a legitimate question of jurisdiction between the state regulated distribution systems and the FERC regulated transmission systems that needs to be clarified prior to the distribution companies passing through costs of studying and upgrading transmission assets to distributed generation facilities on the distribution system. I 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 that generally reduce the need for transmission services and could thus be considered competitors.

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 completely unreasonable that on top of being charged for the full cost of transmission system upgrades, the distribution companies also plan to charge distributed generators 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 were 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" for receiving the services of the transmission system. We are also not aware of any docketed proceeding before the state utility commissions or the FERC in which such charges were reviewed and approved.

Q. Please provide your perspective on National Grid's proposal in Massachusetts DPU 20-75 to allocate up to 40 percent of the DG interconnection costs as system benefits to all customers.

A. It should be clear to everyone that 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. Upgrades provided for project interconnection also provide significant system benefits to all customers.

The question is not a matter of whether these costs should be shared by all ratepayers, but rather a question of what portion should be allocated to specific distributed generation customers and what should be rate-based to all ratepayers? With statutory requirements to reduce greenhouse gas emissions from the electrical sector, the matter becomes more complicated than just calculating the costs and benefits of specific equipment upgrades. At a time when excessive interconnection costs are hampering the development of the clean energy projects needed to reach these legislatively mandated emission reduction targets, a more appropriate allocation of interconnection costs is essential.

Moreover, it is not just a matter of system benefits to ratepayers but also the societal benefits necessary to meet these emissions targets that should be considered in any cost allocation formulas. In light of the mandates faced by the electrical sector, the 40% proposed by National Grid should be considered the minimum allocation to all ratepayers. A more reasonable share would be 60% to 80%.

Q. Please share any concluding thoughts regarding interconnection issues.

There is simply no way possible for Rhode Island to achieve its now mandated clean energy and climate goals with the current burdensome costs and delays being place on the development of distributed renewable energy generation facilities. We cannot wait for the slow traditional regulatory process to reform the interconnection study process and interconnection cost allocation formulas. The Commission should introduce a new docket to expedite necessary changes. The baby steps currently being proposed in RI PUC Docket 5077 are not remotely adequate to address the complete rethinking of the interconnection rules that is clearly called for and necessary.

It is hard to believe that any regulator might consider it either reasonable or fair that distributed generators would be asked to pay the entire cost of distribution system upgrades, the entire cost of transmission system upgrades and then pay again for the entire cost of the transmission system upgrades over about 20 years through "carrying costs".

There should be standardized interconnection costs allocated to all utility customers on an equal per kW basis. These interconnection charges should be based on the capacity of the interconnection to either consume or export electricity to and from the grid. Such charges should be the same for homes consuming electricity as they are for home scale electricity generation. They should be the same for large scale distributed generators as they are for factories or commercial facilities that consume electricity.

In the current absence of real system planning on the part of the utilities and until the entire system can be adequately upgraded for modern bidirectional operation, the vast majority of the necessary system upgrade costs should be rate based. At the same time, the utilities currently allowed rate of return should be significantly reduced and replaced in large part with performance based incentives for actually achieving necessary grid modernization.

Q. Does that conclude your testimony?

A. Yes.