JOINT UTILITIES
OF NEW YORK

Joint Utilities of New York – DER Sourcing / NWA RFPs Stakeholder Webinar
November 9, 2017 – Q&A

BCA HANDBOOKS

Stakeholder Question 1: I applaud the idea that we have transparency on how these solutions are calculated. My fear is that the complexity of the BCAs as they are written right now will cause a lot of extra work done on the side of developers bidding into the RFPs and [for the JU] who is running the BCA. For instance, on one RFP we looked at, there were no limits on how many solicitations you could enter, which could create a lot of drag on the process. Are you developing a tool to apply the BCA?

JU Answer 1: The JU, as a group, does not have any plans right now to develop a tool other than the filed BCA handbooks. Each utility right now is doing their own internal analyses based on the principles within the BCA Handbooks, and may as individual utilities develop their own internal tools. The JU will be reconvening our BCA Handbook working group before utilities submit their updated BCA Handbooks on June 30, 2018. It's something the JU can discuss and determine what, if anything, we can provide to make it easier to use.

Stakeholder Question 2: How do utilities determine the value in the BCA for power reliability or power outage interruptions?

JU Answer 2: There is an entry in the BCA formula which seeks to quantify net avoided outage costs and net avoided restoration costs as benefits to the reliability of the electric system. How that is actually done is based on the available data the utility has for that particular [proposed] solution and the historic reliability of the distribution infrastructure the solution may impact.

Stakeholder Question 3: Is a full BCA calculation needed from a developer when submitting a response to the RFP?

JU Answer 3: No, proposals do not require any BCA calculations provided by the developer. The BCA Handbook has been made public as a way to create more transparency for developers so they might better understand how the utilities will be evaluating the benefits and costs of the proposed solution(s). Utilities do not require developers to perform their own BCA; the utility is, however, required to do the analysis to justify moving forward with an award.

Stakeholder Question 4: Once a project has been approved, will the BCA for the project be public so that developers can better understand how things are being done?

JU Answer 4: The utilities are not planning to make the results public primarily because the BCA contains confidential information about the proposed solutions and the pricing offered from the developers. If a utility does consider providing information, it would be high level and aggregated to protect confidentiality.

Stakeholder Question 5: Are the value of emission reductions resulting from deploying specific DERs for NWA solutions calculated uniquely for the specific RFP and technology or is there some standard publically available emissions values used, specific by technology and perhaps even differentiated by location across the New York State? These emission values are for reduction of GHG, SO_2 and the like.

JU Answer 5: Values for compliance costs of emissions regulations are considered in the BCA Handbook; however they are not technology specific. Stakeholders can reference utility-specific BCA Handbooks with the BCA case number 16-M-0412.

Stakeholder Question 6: Can you please provide the links to each utility's BCA Handbook?

JU Answer 6: The BCA case number is 16-M-0412. The last versions of the BCA Handbooks were published in August 2016:
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0412

LOCALIZED NEEDS

Many of the questions during this Q&A session were directed to Con Edison following their presentation and may not be applicable to the other utilities.

Stakeholder Question 1: What is the reason that a 1 MW customer is only relieving the feeder by 100 kW? Is it because of the location?

JU Answer 1: All customers in a mesh distribution network are supplied by multiple feeders to serve their total load, therefore each feeder only has a fractional impact on the need. The total reduction to one feeder is not necessarily the same as the reduction on another feeder because the impedance from each feeder to each customer varies based on cable length, size, and available paths power can flow. This roughly translates to a general statement that the closer a customer is physically to a feeder, the higher the fractional impact on the total need supplied by that feeder will be For example, if a customer has 1/5 of their load supplied by a feeder, every 1MW of reduction in load leads to 200kW reduction on that feeder. We call this fraction the distribution factor, and represent it as a percent, in this example 20%.

Stakeholder Question 2: Regarding spatial considerations, would you have a different view on the diminished value of an asset if it is connected to the high or low side of a substation or would they be considered similarly?

JU Answer 2: When you have a feeder level project, the relief has to come from the customer side, downstream from the substation overload. If you are trying to relieve a feeder level project, it comes down to how utilities build their portfolios. We need to have enough resources that provide total reduction to that feeder itself, given the electrical behavior of the network. Ultimately it means we will have more total relief to the substation but need to be sure the relief is provided to the specific feeder.

Stakeholder Question 3: For projects on a network, can developers expect to receive more detailed information in the RFPs about the feeder as a whole? (i.e., how many residences are in the 50% -60% or 5% as opposed to the number of customers?)

JU Answer 3: Each utility can talk more about sharing the more detailed information during the project-specific webinars. In general, utilities are providing aggregated demographics for the feeder. If a developer is working with a specific customer within the Williamsburg area [and receives permission from the customer to receive customer information], Con Ed can share the distribution factor if requested via email with the customer name, address, and account number. The more granular information gets, privacy issues have to be considered.

Stakeholder Question 4: Are utilities considering CVR for load relief projects?

JU Answer 4: If developers would like to know additional details pertaining to specific RFPs that are currently out there, please direct your questions to each utility individually during the separate utility-specific RFP webinars.

Stakeholder Question 5: To all the JU who are doing feeder level programs, it would be extremely helpful to developers to have the demographics isolated to the facilities or the populations that would be impacted. There is a big chunk of the feeder that has zero impact so it is difficult for developers to interpret the demographic data. Are the other utilities considering a similar approach to Con Edison's approach for Williamsburg, and would it be possible to narrow down the RFPs to the accounts that would make a difference? We applaud Con Edison for their heat map solution.

JU Answer 5: It will depend on the project, the data which is available, and the need to aggregate customer data for privacy considerations. The JU try to put as much information out in the RFPs as possible in the interest of getting the best proposals back and will take this under consideration for future projects.

Stakeholder Question 6: There will be other NWAs that have the same distribution factoring in the resource requirement (specific to Con Edison network areas). We would be concerned about the performance penalty calculations. It seems like they would be complicated to calculate them either before starting or after the fact. Please comment on your perspectives.

JU Answer 6: The distribution factor itself is a property of the electric system and it doesn't change often. Once we get to contract negotiations with the developer, we would talk about performance at the site itself and not at the feeder level. A developer needs to perform at a certain output at the site.

INTERCONNNECTION PROCESS

Stakeholder Question 1: Can utilities expand on the types of projects that need to apply through interconnection process, specifically BTM projects?

JU Answer 1: The JU encourages developers to ask questions of utility interconnection groups or NWA teams when submitting an interconnection application. As a general rule, any resource that would require a physical interconnection to the system (battery, wind, storage, DG, etc.) would need to go through an interconnection application process.

Stakeholder Question 2: For storage, do you need to file an interconnection [application] for each of the batteries of the project? Or can a developer file an aggregated interconnection [application]?

JU Answer 2: Specific interconnection application requirements may vary by utility, and developers should contact the company interconnection group for the RFP they are considering.

Stakeholder Question 3: There is still confusion regarding the system improvement costs. If BTM systems are further away from the feeder would wires need to be upgraded?

JU Answer 3: It depends on the scenario or the project and the resource being interconnected. Different resources located at different points on different utility systems will require different system upgrades. The cost of any physical equipment that would need to be added to the utility distribution system to ensure safe, reliable operation of the resource on the system will need to be included or accounted for in a response to an RFP. For the RFPs that you are participating in, communicate to the utility whether or not you included system upgrade costs in your proposal. Regardless of whether or not the system improvement/interconnection costs are included in a developer's proposal; those costs must be reflected as costs in the BCA.

Stakeholder Question 4: Will utilities provide the avoided costs associated with traditional projects that have been replaced by alternative solutions, in particular feeder upgrades? If specific costs won't be provided, can utilities provide a range of prices for the traditional solutions? It is helpful for parties to know the scope of the projects.

JU Answer 4: At this point in time for RFPs, most utilities do not include the traditional costs being avoided. NYSEG/RG&E does publish the budgeted cost of traditional wires solution. However NYSEG/RGE also includes language which explains how they calculate the deferral value (the deferral value itself is not provided), and notes that the deferral value is actually "the price to beat," NOT the cost of the traditional solution. NYSEG/RGE provides the information about the cost of the traditional solution so that parties can have an idea of the financial magnitude of the project. As for providing a range for the costs of traditional solutions, the JU will continue to discuss this issue.

Stakeholder Question 5: When there is a substation type of interconnect, it would be helpful to know at the time of the RFP if there are other things that can impact interconnection costs.

JU Answer 5: The JU will consider as a working group. Utilities are trying to share as much information as possible and encourage suggestions for helpful information.

RFP PROCESS ACTIVITIES

Stakeholder Question 1: Information about the availability of utility owned sites (including substations and surrounding land) which battery or other new technology developer can use to respond to NWA RFPs has been inconsistent between utilities and in some cases the availability has changed between the time of the original RFP and the shortlist RFP refresh. The availability of utility owned land is critical information for a developer to have in order to make a "front end" decision as to whether or not to respond to a NWA RFP. Company owned sites provide many advantages for developing the speediest and lowest cost solution, including ease of permitting, minimized local stakeholder processes, interconnection ease/cost minimization and developer "development" time and cost. Given that REV has a context of finding new revenue streams for utilities, why are there inconsistencies between utilities on this subject? Our experience is that they range from "no access period, no discussion" to very helpful upfront info. NYSEG's Gardenville RFP Q&A numbers 2-4 are an example of a clear and very effective approach to site availability communication and support.

JU Answer 1: The JU will consider this question as a group, as answers vary by utility.

- National Grid: Leasing or otherwise making utility-owned land available to NWA developers is a time consuming process which includes valuing land, making sure the ratepayers are compensated for the exact property value, and utility filing with the Commission to lease that land. As a result, National Grid has requested that parties find their own land due to expediency.
- Con Edison: Availability of utility owned land for ConEd projects will be determined on a case by case basis. Generally we consider geographically where the need is; and in that area do we have utility property available; and what is planned for that utility property use now or in the future. At least in one case, we allowed use of utility property for a new technology.
- NYSEG/RG&E: This will be determined on a case by case basis and a lot of different variables go into it. If there is land available, it will be included in the RFP.
- Orange and Rockland: Availability of property for NWA use is determined on a case by case basis. O&R considers the following when making its determination; will the NWA solution interfere with O&R's future plan of use, can both utilize the site and if not, how quickly can the NWA be removed to allow O&R's use if plans change, are there other sites in the area available, and is this the best site for the solution.

- Central Hudson: Many different variables influence the availability of a utility-owned site for NWA solutions. In many cases, utility-owned land is not suitable to meet the project needs based on availability of space or viability of the interconnection location. Central Hudson will consider this approach for future NWA's, though. If utility land has been deemed viable for siting a DER that will be included within the RFP.

Stakeholder Question 2: I understand there can be potential regulatory headaches with using utility property under these circumstances (see Question 1 above), but how about using different property with in front of the meter set-up (e.g., purchasing your own property and injecting onto a feeder and/or using an existing customer's property).

JU Answer 2: Utilities are open to further discussion on using customer property for in front of the meter installations.

Stakeholder Question 3: It's difficult to understand which customers will be included or not included within an RFP area. As locational value is included more and more, it would be helpful if utility portals would indicate which types of customers are included in an RFP area. Are there plans to either add onto the a) customer's utility bill or b) portal that the customers log into, something that displays what feeders or circuits the customers are on so that we can identify customers by locational area earlier in the process?

JU Answer 3: Utilities will take that into consideration for further discussion as a working group. The circuit maps which are published now for all New York utilities are a starting point today, and will be improved over time.