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November 27, 2024

VIA ELECTRONIC DELIVERY

Honorable Michelle L. Phillips
Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

RE: Case 24-E-0621 – Petition of the IPWG/ITWG Members Seeking Certain Minor Amendments to the New York State Standardized Requirements (SIR) for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems

Dear Secretary Phillips:

Enclosed please find for filing the subject petition on behalf of the following members of the Interconnection Policy Working Group ("IPWG") and the Interconnection Technical Working Group ("ITWG") comprised of Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation ("Joint Utilities"), and New York Solar Energy Industries Association, Ascent Renewables LLC, Carson Power LLC, ClearPath Energy, CVE North America, Distributed Sun LLC, EmPower Solar, Encore Renewable Energy, GreenSpark Solar, GridEdge Networks, Kassselman Solar, LLC, Kendall Sustainable Infrastructure, LLC, Lodestar Energy, Montante Solar, New Energy Equity, New Leaf Energy, Inc., NineDot Energy, Norbut Solar Farms, Pfister Energy, Pivot Energy, PowerFlex, Reactivate, RIC Energy, Sol Source Power, LLC, Solar Liberty, Soltage, LLC, Third Pillar Solar, TJA Clean Energy, Trail Ridge Power, US Light Energy, and 64 Solar LLC (collectively, "IPWG/ITWG Members").

Respectfully submitted on behalf of
the IPWG/ITWG Members,

/s/ Janet M. Audunson

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Enc.

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems	)))))	Case 24-E-0621

PETITION OF THE IPWG/ITWG MEMBERS SEEKING CERTAIN MINOR AMENDMENTS TO THE NEW YORK STATE STANDARDIZED INTERCONNECTION REQUIREMENTS (SIR) FOR NEW DISTRIBUTED GENERATORS AND/OR ENERGY STORAGE SYSTEMS 5 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS

Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the Joint Utilities), and the New York Solar Energy Industries Association (NYSEIA), Ascent Renewables LLC, Carson Power LLC, ClearPath Energy, CVE North America, Distributed Sun LLC, EmPower Solar, Encore Renewable Energy, GreenSpark Solar, GridEdge Networks, Kasselman Solar, LLC, Kendall Sustainable Infrastructure, LLC, Lodestar Energy, Montante Solar, New Energy Equity, New Leaf Energy, Inc. NineDot Energy, Norbut Solar Farms, Pfister Energy, Pivot Energy, PowerFlex, Reactivate, RIC Energy, Sol Source Power, LLC, Solar Liberty, Soltage, LLC, Third Pillar Solar, TJA Clean Energy, Trail Ridge Power, US Light Energy, and 64 Solar LLC, as members of the Interconnection Policy Working Group (“IPWG”) and/or the Interconnection Technical Working Group (ITWG) (collectively, the IPWG/ITWG Members) hereby petition the New York Public Service

Commission (Commission) for approval of certain cost-sharing timeline amendments to Appendix E of the February 1, 2024 version of the *New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems* (February 2024 SIR).[1] The IPWG/ITWG Members have collaborated with the New York State Department of Public Service (DPS) Staff to reach consensus on this proposal. Specifically, the IPWG/ITWG Members are seeking Commission approval to adjust the non-refundable payments set out in the February 2024 SIR for cost-sharing qualifying upgrades from the date of the 25% payment milestone to the date of the 75% payment milestone so as to accommodate the timelines more typically encountered in securing municipal permits for proposed interconnection projects.

Additionally, the IPWG/ITWG Members hereby petition the Commission for approval of certain amendments to Appendix G of the February 2024 SIR that would modify the supplemental screening criteria to improve effectiveness of these screens for smaller systems. Lastly, the IPWG/ITWG Members petition the Commission for approval of certain amendments to Appendix K of the February 2024 SIR so as to require interconnection applicants to provide energy storage schedules that optimize energy storage system injections into the electric grid, thereby improving overall grid efficiency and avoiding unnecessary distribution upgrades.

This petition sets forth the IPWG/ITWG Members' recommended amendments to Appendices E, G, and K of the February 2024 SIR to implement these changes. These

[1] The Commission approved the February 2024 SIR in Case 22-E-0137, *Petition of New York State Office of Parks, Recreation & Historic Preservation, State University of New York, New York State Department of Transportation and City of New York, for an Amendment to Appendix A of the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems*, Order Approving Interconnection Contract for State Entities Modifying Standardized Interconnection Requirements (issued January 18, 2024).

recommended amendments are provided in redline format in the respective Appendices E, G, and K attached hereto. An explanation of those edits is also provided within this petition.

I. RECOMMENDED AMENDMENTS TO APPENDIX E

Over the past two years, with increasing frequency, interconnection applicants have encountered significant challenges in advancing municipal permit applications[2] and where permits are issued, it does not occur in the expected timeframe. Typically, interconnection applicants commence the municipal permitting process concurrently with the interconnection application process under the SIR. In that way, applicants are able to evaluate the hurdles in achieving siting approval coincident with the interconnection scope of work in a manner that will fit within the SIR queue process and associated timelines.

The cost-sharing provisions of the SIR utilize a pro rata approach whereby an interconnection applicant pays only for the specific distribution hosting capacity assigned to its project for defined types of utility system modifications.[3] The pro rata approach takes the estimated cost of an upgrade and divides that cost by the total increased hosting capacity created by the upgrade, thereby creating a dollar per kilowatt (kW) cost. That dollar per kW value is then multiplied by an individual cost-sharing project's AC nameplate rating in kW to determine the applicant's pro rata cost share.[4]

However, the cost-sharing payments of qualifying projects are non-refundable to a participating project that is subsequently withdrawn from the interconnection queue until/unless a subsequent project(s) take its place by making payments that equal or exceed the payments

[2] In some instances, municipalities have imposed moratoriums or outright prohibitions on siting certain types of distributed energy resource (DER) projects.
[3] February 2024 SIR, Exhibit E, p. 1.
[4] *Id*., Exhibit E, pp. 1-2.

made by the withdrawing project. This creates a financial hardship when an interconnection applicant incurs a protracted permitting process and may discourage an applicant from pursuing certain projects subject to cost sharing. The proposed amendments to Appendix E will 1) move all pro-rata qualifying upgrade payments from the 25% payment date to the 75% payment date; and 2) continue the practice of requiring 25% and 75% payment milestones for Market-Initiated "Distribution and Sub-Transmission Lines and Underground Secondary Network Upgrades", while making the 25% payment refundable until such time as the 75% payment is due, at which time both payments become non-refundable. This change to the SIR will better align the interconnection process with municipal permitting processes and provide interconnection applicants additional time to secure such permits without putting the initial 25% payment at risk until such time as the 75% payment, as well as the cost-sharing payment (Qualifying Upgrade Charge), are due to the utility. To accomplish this change, the following revisions are proposed to Appendix E of the February 2024 SIR.

A. Section 2 Market-Initiated Upgrades

1. On page 5, Section A, third paragraph, it is proposed that additional requirements be added stipulating that the applicant shall pay 25% of the project-specific costs to the utility within ninety (90) business days following delivery of the Coordinated Electric System Interconnection Review (CESIR) with 75% of the project-specific costs and Qualifying Upgrade Charge to be paid within one hundred and twenty (120) business days from the utility's receipt of the 25% payment. This additional language will serve to make it clear that the non-refundable cost-sharing payment is due at the second milestone.

2. On page 5, Section A, fourth paragraph, it is proposed that additional requirements be added stipulating, for clarity, that both Triggering Projects and Sharing Project(s) shall make 25% and 75% payments to the utility. Further, the language adjusting the non-refundable payment requirement is proposed to be added to this same paragraph stating that the 25% payment is refundable until the applicant makes the 75%payment to the utility at which point in time both payments become non-refundable.
3. On page 5, Section A, end of fourth paragraph, it is proposed that discretion be granted to the Triggering Project to opt out of cost sharing until the 75% payment due date to the utility, and thereafter classifying the upgrade as a project specific non-shared upgrade subject to the rules set forth in Section 1-D of the SIR. Additional language has been added to capture this proposal.
4. On page 6, Section B, within the table entitled "Market-Initiated Cost-Sharing 2.0 Mechanisms", it is proposed to add a statement to the last column entitled "Refundability and Reconciliation" opposite the "Market-Initiated Qualifying Upgrade" entitled "Distribution and Sub-Transmission Lines and Underground Secondary Network Upgrades" for reinforcement and consistency that the "25% payment is refundable until the project makes the 75% payment at which time both payments become non-refundable."

II. RECOMMENDED AMENDMENTS TO APPENDIX G

Preliminary screening assesses the feasibility of a distributed generation (DG) project to pursue a streamlined interconnection process. It serves as a sorting mechanism to determine whether a project is suitable for a Supplemental Study or if a CESIR is more appropriate.

Supplemental screening involves a relatively detailed assessment designed to provide a time- and cost-efficient interconnection process for smaller DERs, typically those under 500 kW. This screening evaluates projects based on three criteria, as outlined in Appendix G appended hereto at Screen G.

The increase in DER penetration levels has made Screen G less effective for smaller systems. If projects fail the Screen G penetration test a CESIR is required which can be a cost prohibitive and time-consuming process for these smaller projects. Additionally, because of the way the screens are structured, the presence of a single large DER (>1 MW) in the queue results in the failure of all subsequent projects, regardless of their size.

Modifying Screen G will allow utility engineers to perform a more granular assessment, verifying whether the grid equipment rating is sufficient to accommodate backfeeding.[5] This makes the interconnection process more efficient by eliminating the need for a CESIR for certain projects. To accomplish this change, the following revisions are proposed to Appendix E of the February 2024 SIR.

1. On page 3, under Screen E: Simplified Penetration Test, first paragraph, it is proposed that additional requirements be added immediately after "…is less than" in line 2 to provide specificity for the alternative to merely using 15% of the annual peak load in determining if the proposed project passes or fails this screen.
2. On page 3, under the subject heading SUPPLEMENTAL SCREENING ANALYSIS, it is proposed to replace the title of "Screen G: Supplemental Penetration Test" with "Screen G: Reverse Power Flow Test" and strike the explanatory paragraph that follows and substitute with new language appropriate

[5] Backfeeding occurs when electricity flows in the opposite direction of its normal flow.

for a reverse power flow test. The Supplemental Penetration Test is being replaced with the Reverse Power Flow Test in order to efficiently study the impact of a proposed DER project on high DER penetration feeders.

III. RECOMMENDED AMENDMENTS TO APPENDIX K

The recommended amendments to Appendix K seek to enable the use of energy storage schedules to optimize the integration of storage systems with the electric grid and thereby improve overall grid efficiency. Currently, utilities must plan for worst-case scenarios where storage systems charge and discharge at maximum capacity. This leads to overestimating grid demands and necessitating costly infrastructure upgrades to accommodate extreme energy fluctuations. By establishing scheduled charging and discharging, utilities can more effectively match storage operations with actual grid conditions, thereby reducing the need for overbuilt infrastructure and providing additional hosting capacity for other DERs (e.g., solar and wind). Projects committing to these granular schedules can minimize strain on the grid during peak times and enhance system efficiency by optimizing the use of existing grid resources. To accomplish this change, the following revisions are proposed to Appendix K of the February 2024 SIR that will seek additional details on the proposed energy storage system from the project applicant to assist the utility in improving energy storage system studies.

Application Requirements

1. On page 1, item a., it is proposed to add the clarifying statement "(if information is available)" following the second sentence along with an instructional third sentence immediately thereafter. An additional paragraph is further proposed at Item a. to provide an example of the specific types of information being sought by the utility.

2. On pages 2 and 3, it is proposed to replace item d., inclusive of items 1 and 2, in its entirety. A new Table 1 entitled “DER Nameplate Rating” and a new Table 2 entitled “Storage Capacity” are proposed seeking additional details on the proposed storage system.
3. On page 3, at item i., it is proposed to add sub-items 3 and 4 seeking additional details on the proposed storage system.
4. On page 4, within item j., it is proposed to add additional content, inclusive of a new Table 3, seeking additional details on the proposed storage system.
5. On page 4, it is proposed to replace item n. in its entirety followed by a new Table 4 entitled “Preferred Study Operations Window” and a new Table 5 entitled “24/7 Charging and Discharging Schedule” seeking additional details on the proposed storage system.

IV. CONCLUSION

Wherefore, for the aforementioned reasons, the IPWG/ITWG Members respectfully request that the Commission approve the proposed amendments to the February 2024 SIR as delineated above. As to Appendix E, the proposed amendments will better align the SIR payment milestones with municipal permitting process timelines so that interconnection applicants will not have to make non-refundable, cost-sharing payments to utilities before project siting applications are addressed by municipalities. As to Appendix G, the proposed amendments will provide adjustments to the supplemental screening criteria to improve the effectiveness of these screens for smaller DG systems. As to Appendix K, the proposed amendments will enable the use of energy storage schedules to optimize energy storage system integration with the electric grid and thereby improve overall grid efficiency.

Dated: November 27, 2024

Respectfully submitted,

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APPENDIX E REDLINE

APPENDIX E -

COST SHARING FOR SYSTEM MODIFICATIONS & COST RESPONSIBILITY FOR DEDICATED TRANSFORMER(S) AND OTHER SAFETY EQUIPMENT FOR NET METERED CUSTOMERS

Generator Type	Generator Size	Equipment Cost to **Residential** Net Metered Customers	Equipment Cost to **Non-Residential** Net Metered Customers****
Micro-CHP	Less than or equal to 10 kW	$350 maximum	N/A
Fuel Cell	Less than or equal to 10 kW	$350 maximum	As determined by Utility*
Fuel Cell****	Over 10 kW up to 2 MW	N/A	As determined by Utility*
Solar	Less than or equal to 25 kW	$350 maximum	$350 maximum
Solar****	Over 25 kW up to 2 MW	N/A	As determined by Utility*
Micro-hydroelectric	Less than or equal to 25 kW	$350 maximum	As determined by Utility*
Micro-hydroelectric****	Over 25 kW up to 2 MW	N/A	As determined by Utility*
Wind **	Less than or equal to 25 kW	$750 maximum	$750 maximum
Wind****	Over 25 kW up to 2 MW	N/A	As determined by Utility*
Farm Wind ***	Over 25 kW up to 500 kW	N/A	$5,000 maximum***
Farm Waste ***	Up to 2 MW	N/A	$5,000 maximum***

* Subject to review by the Commission at the request of the Customer. Such costs can include the total costs for upgrades to ensure the adequacy of the distribution system which would not have been necessary but for the interconnection of the net metered DG resource (as per PSL §66-l(3)(c)(iii)).

** Residential and Non-Residential Wind Customers with a total rated capacity up to 25 kW, Farm Wind may be required to also pay for feeder line upgrades that would not be required but for the interconnection of the net metered DG resource. Residential and Non-Residential Wind, and Farm Wind Customers are responsible for all feeder line upgrade costs if the total nameplate rating of the generating equipment exceeds 20% of the rated capacity of the feeder line (as per PSL §66-l(5)(c)(ii)). Farm Wind Customers are responsible for 50% of feeder line upgrade costs if the total nameplate rating of the generating equipment does not exceed 20% of the rated capacity of the feeder line (as per PSL §66-l(2)).

*** For Farm Wind projects with a total nameplate rating of the generation equipment that does not exceed 20% of the rated capacity of the local feeder line to which the project will connect, that portion of the CESIR costs related to transformers or other equipment installed at the customer's site is included in the $5,000 limitation; however, the customer is also responsible for 50% of the CESIR costs related to feeder line upgrades. Farm Wind projects with a total nameplate rating of the generation equipment that does exceed 20% of the rated capacity of the local feeder line to which the project will connect, CESIR costs related to transformers or other equipment installed at the customer's site is included in the $5,000 limitation; however, Farm Wind customers are responsible for the CESIR costs related to feeder line upgrades.

**** The first project triggering an eligible upgrade will initially bear 100% of the cost, while subsequent projects benefitting from those upgrades will reimburse the first project developer. The share of the costs paid by subsequent developers shall be calculated by the utility as the ratio of the total upgrade cost to the total AC watts the upgrade serves. If a third project uses the upgrade, the utility will perform a new calculation based on the new number of total watts served; the third project will pay its share and the utility will divide the third project's contribution among the first two projects. Sharing continues according to this formula until the capacity of the upgrade is used up or the net costs to the participating projects falls to $100,000 or lower, whichever comes first. The utilities shall administer the allocation process and track the payments among contributing projects. The utilities are authorized to collect a $750 fee from applicants for processing each reimbursement. The Equipment Upgrade Cost Sharing Requirement is limited in several ways. First, cost sharing only applies to substation 3V0 protection, substation transformer upgrades, and other substation-level shared upgrades. Second, only those upgrades that cost in excess of $250,000 are subject to sharing. Third, projects below 200 kW AC in size are not required to participate.

Cost Sharing for Qualifying Upgrades

The cost-sharing provisions herein apply to two categories of system modifications: Utility-Initiated Upgrades and Market-Initiated Upgrades, as defined below, both which utilize a pro rata approach whereby the applicant pays only for the specific distribution hosting capacity assigned to its project for these types of system modifications. A pro rata approach consists of taking the estimated cost of an upgrade and dividing that cost by the total increased Hosting Capacity created by the upgrade, thereby creating a dollar per kW cost which will then be multiplied by an individual project's AC nameplate rating in kW to determine the applicant's pro rata cost share. The rules specified in Section I. Application Process will continue to govern applicants' cost obligations with respect to all other system modifications.

1. Utility-Initiated Upgrades

The category of Utility-Initiated Upgrades consists of substation transformer bank (bank) installations or replacements and proactive zero sequence voltage (3V0) installations. Each utility shall identify its proposed Utility-Initiated Upgrades in its annual Capital Investment Plan (CIP). Each year, when the CIP is filed with the Commission, the utility will publish a link to the CIP on its system data portal and a list of those substations included in the CIP that are eligible for cost sharing hereunder as Utility-Initiated Upgrades where the utility plans to complete engineering within the next twenty-four (24) months. The utility will describe the scope of the upgrade to be performed at each such substation by providing planned design/construction schedules and funding estimates required to accommodate additional DG/ESS interconnections. After the established application deadline as defined below, the utility shall determine a pro rata cost per kW for the upgrade at each relevant substation.

A. Bank Upgrades (Proposed Multi-value Distribution Projects)

In the course of its planning process, at the time when the utility identifies the need to install or replace a bank due to asset condition, reliability, safety, resiliency, or capacity requirements, the utility shall consider options for designing the new bank equipment to create greater DG/ESS Hosting Capacity than the baseline installation would create. If the bank can be upgraded to increase Hosting Capacity while solving a pre-existing asset condition, reliability, safety, resiliency, or capacity issue, and if there is market interest that indicates DG/ESS growth above the capacity of the baseline equipment, the utility will identify the enhanced installation or replacement in the next published CIP as a Multi-value Distribution ("MVD") project. The utility will fund the cost of the baseline project. Participating Projects will fund the difference between the baseline and the MVD project cost.

If the utility determines, in its sole discretion, that there is sufficient time in the CIP project schedule (where "sufficient time" is baseline project specific and includes baseline projects where final design and engineering is not complete and prior to procurement) to allow additional DG/ESS developers to submit interconnection applications, the utility will publish a deadline for such applications on its system data portal with the link to the CIP. The utility notice will describe the baseline installation to be performed and the corresponding design/construction plan for the proposed baseline project. Within thirty (30) Business Days after the application deadline, the utility will calculate a cost per kW[1] for the upgrade for each project with an approved application to participate in the MVD Project Study and will provide that information and an invoice for MVD Project Study costs to each applicant. Applicants will have 10 Business Days to pay their share of the study costs; applicants who make this payment on time will be considered Participating Projects. Once Participating Projects commit to participate in the MVD Project Study, which requires the payment of their respective MVD Project Study cost share, Participating Projects will also be subject to CESIR payment timelines for project specific non-shared costs as per Section I-D. The utility will start the MVD Project Study and Participating Project CESIRs once the MVD Project Study and CESIR payments are received. If Participating Projects do not meet payment timelines and are withdrawn from queue, the pro rata cost per kW remains the same for remaining Participating Projects, and the Utility will have discretion on whether enough is collected to justify proceeding with the MVD project. The utility will have one hundred (100) Business Days to complete both the MVD Project Study and each Participating Project's CESIR.

The MVD Project Study result will include an indication of the incremental project equipment, Hosting Capacity enabled, preliminary milestone schedule, and revised cost per kW required to interconnect Participating Projects as part of the proposed MVD project. If the MVD Project Study indicates that the aggregate Participating Project capacity exceeds the capacity of the MVD project, the capacity will be assigned by interconnection queue position. After the MVD Project Study results are provided to the Participating Projects, for those Participating Projects where the MVD Study confirms available increased Hosting Capacity, a non-refundable full MVD Qualifying Upgrade payment for the shared costs of proceeding with the MVD project will be due within ninety (90) Business Days from each of the Participating Projects that want to proceed. If projects are withdrawn from the queue such that additional Participating Projects in queue can now benefit from Hosting Capacity created by the Qualifying Upgrade, the utility will send invoices to additional Participating Projects where the MVD project can now meet their Hosting Capacity needs. Applicants who receive an invoice under this provision shall pay the invoice within 30 Business Days or be withdrawn from the queue.

Based on the number of DG/ESS applicants that pay the non-refundable MVD Qualifying Upgrade payment and the CIP project schedule, the utility will have the discretion to move ahead with the MVD project. If the utility determines it will not proceed with the MVD project, it will provide notice of its decision and rationale to Participating Projects within fifteen (15) Business Days of receipt of the MVD Qualifying Upgrade payment and will refund those payments via the utility cost reconciliation process per Section 1-C. No MVD Qualifying Upgrade payments will be refunded to Participating Projects that are withdrawn from the queue after making such payments until/unless a subsequent project(s) take their place by making MVD Qualifying Payments that equal or exceed the MVD Qualifying Payments received from those withdrawing Participating Projects.

B. Proactive 3V0 Upgrades

The CIP will identify substations at which the utility plans to install 3V0 upgrades. Following the utility's filing of the CIP, additional applicants may apply for interconnection at the identified substations. The utility will accept applications at a substation designated for a 3V0 upgrade up to the maximum capacity available at the site for reliable and safe operation. The utility will have the discretion to proceed where 3V0 upgrades are feasible. Payments will be due in accordance with CESIR payment timelines as per Section 1-D.

2. Market-Initiated Upgrades

This section addresses cost-sharing for Qualifying Upgrades identified in the course of the interconnection application process.

A. Process for Market-Initiated Upgrades

Whenever the utility determines that a substation Qualifying Upgrade is required to interconnect a Triggering Project, the utility will promptly discuss its finding with the applicant. If the applicant decides to continue with the application, then in addition to the CESIR process outlined in Section I-C, the utility will proceed with a more detailed study to develop a cost estimate and initial construction schedule for the Qualifying Upgrade. The utility will determine the Qualifying Upgrade Cost and the net increase in Hosting Capacity that would result from the construction of that modification. The utility shall have up to forty (40) Business Days to conduct the additional study to assess the Qualifying Upgrade and complete the CESIR. The utility will present the Qualifying Upgrade use case and supporting details in the Qualifying Upgrade Disclosure, which will include the following items:

1. The technology option(s) considered to address the electric system impacts;
2. The Qualifying Upgrade selected by the utility;
3. The estimated Qualifying Upgrade Cost and increase in Hosting Capacity;
4. The estimated Capacity Increase Shared Cost (per kW AC); and
5. A Preliminary Milestone schedule for the Qualifying Upgrade.

The utility will also publish the Qualifying Upgrade Disclosure with the next monthly update to the utility's system data portal after the CESIR is delivered to the Triggering Project applicant.

The CESIR will assign the Triggering Project and any Sharing Project its Qualifying Upgrade Charge. In accordance with the requirements of Section 1-D, e~~E~~ach applicant shall pay ~~the Qualifying Upgrade Charge ninety (90) Business Days following the CESIR delivery, and~~ 25% of the project specific costs ninety (90) Business Days following the CESIR delivery and pay ~~the~~ 75% of the project specific costs and Qualifying Upgrade Charge one hundred and twenty (120) Business Days from when the utility confirms receipt of the 25% ~~payment in accordance with the requirements of Section 1-D~~. No Qualifying Upgrade Charge payments will be refunded to Participating Projects that are withdrawn from the queue after making the such payments until/unless a subsequent project(s) take their place by making Qualifying Upgrade Charge payments that equal or exceed the Qualifying Upgrade Charge payments made by the withdrawing Participating Projects.

For Qualifying Upgrades that are distribution/sub-transmission line and underground secondary network upgrades,[2] the utility shall charge the Triggering Project the full cost estimate for the Qualifying Upgrade as established in the CESIR. ~~Payments shall be made i~~In accordance with the requirements of Section I-D, Triggering Project and Sharing Project(s) shall make 25% and~~&~~ 75% payments. The 25% payment is refundable until the project makes the 75% payment at which time both payments become non-refundable. At the time the Triggering Project applicant makes its first payment, the utility shall designate the upgrade as a "DG/ESS Encumbered Line." Construction of the upgrade shall begin once the utility has received full payment of the cost estimate. Any Sharing Project(s) above 50 kW AC that later proceeds to CESIR will be charged its pro rata share of the Qualifying Upgrade. The utility will calculate the pro rata share based on the capacity of the DG/ESS project and footage used. After five years from the first project interconnection, or when the Triggering Project's contribution after reimbursement becomes less than $100,000, whichever occurs first, the line will no longer be considered a "DG/ESS Encumbered Line." No payments shall be refunded to a Sharing Project(s) after making full payment until a subsequent project(s) takes their place by making their full payment. At the discretion of the applicant, the Triggering P~~p~~roject can opt out of cost sharing until the 75% payment date, thereby classifying the upgrade as a project specific non-shared upgrade and be subject to the rules for project specific non-shared costs as per Section I-D.

B. Project Profiles to Be Considered in Site Selection and Eligible for the Market-Initiated DG/ESS Upgrade Mechanism

Participating Projects must be greater than 50 kW AC nameplate rating in size, or Participating Projects proposed by the same developer, within a six-month period, must be greater than 50 kW AC nameplate rating in aggregate.

The table below, "Market-Initiated Cost Sharing 2.0 Mechanisms", provides a breakdown of Triggering and Sharing project cost responsibilities, Mobilization Threshold, and Refundability/Reconciliation of the various Market-Initiated Qualifying Upgrade mechanisms.

Market-Initiated Cost Sharing 2.0 Mechanisms

Market-Initiated Qualifying Upgrade	**CESIR Cost Responsibility**		**Mobilization Threshold**	**Refundability and Reconciliation**
	Triggering Project	**Sharing Project**		
Distribution and Sub-Transmission Lines and Underground Secondary Network Upgrades	100% of Qualifying Upgrade Cost	Pro-Rata Share based on kW Capacity and Footage	Upon payment of 100% of Qualifying Upgrade Cost by Triggering Project	The 25% payment is refundable until the project makes the 75% payment at which time ~~point~~ both payments become non-refundable. Qualifying Upgrade Costs are non-refundable for the Triggering Project until a Sharing Project provides payment such that the utility has receipt of 100% of Qualifying Upgrade Cost. Upon receipt of additional payments by Sharing Projects the utility shall reconcile with the Triggering Project based on a

				calculated estimated pro-rata share. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.
Transformer Bank	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Upon payment of 75% of Qualifying Upgrade Cost by Triggering Project and Sharing Project(s)	Qualifying Upgrade Costs are non-refundable until another Sharing Project provides payment such that the utility has received payments equal to the pro-rata share of the Qualifying Upgrade. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.

Other Qualifying Substation Upgrades	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Upon payment of 25% of Qualifying Upgrade Cost by Triggering Project and Sharing Project(s)	Qualifying Upgrade Costs are non-refundable until another Sharing Project provides payment such that the utility has received payments equal to the pro-rata share of the Qualifying Upgrade. Remaining reconciliation for Qualifying Upgrade Costs to occur pursuant to Section I-C of the SIR.

C. Utility Mobilization Thresholds

The utility shall proceed to construct a Qualifying Upgrade, other than a distribution/sub-transmission line upgrade or underground secondary network upgrade, once it has collected sufficient funds from the Triggering and Sharing Project(s) in accordance with the following:

1. For all substation upgrades other than a transformer installation/upgrade, the utility shall proceed once Participating Project payments total at least 25% of the estimated Qualifying Upgrade Cost.
2. For a substation transformer installation/upgrade and associated work, construction shall begin once payments made by Participating Projects equal at least 75% of the estimated Qualifying Upgrade Cost. If the 75% threshold is not collected within twelve (12) months of an applicant paying its full construction contribution, then the applicant may request a refund, which the utility shall process within sixty (60) Business Days of the request.
3. If Triggering Project and Sharing Project(s) Hosting Capacity needs are below the minimum subscription threshold, the Triggering Project, or the Triggering Project and any Sharing Project(s), may agree to fund shares beyond their capacity needs so that the minimum subscription threshold criterion is met.
4. To mitigate the risk to utility customers, unrecovered costs shall be capped at 2% of a utility's distribution/sub-transmission electric capital investment budget per fiscal year, after which any Qualifying Upgrades would require full (100%) funding from Triggering Projects and Sharing Projects prior to utility mobilization for such projects' construction work.

3. Capital Project Queues

The utility will create a Capital Project Queue at the substation or feeder level for each Utility-Initiated Upgrade and Market-Initiated Upgrade identified under these rules where utility construction will take longer than twenty-four (24) months. The utility will note on its Hosting

Capacity map that the station/feeder is impacted by the Capital Project Queue due to future work.

Applications pending at the time a Capital Project Queue is created will be placed into the queue if the applicant consents. New applications will be placed into a Capital Project Queue following the Preliminary Screening Analysis. The payment timelines in Section 1-D will be suspended for applications assigned to a Capital Project Queue, except as provided otherwise in this Section.

When the upgrade for a given substation is within eighteen (18) months of the expected completion date, applications will be removed from in the Capital Project Queue and will advance through the remaining SIR steps based on their original application completion date. Any project that was placed in the Capital Project Queue after the CESIR was complete will need to go through the CESIR process again due to potential changes to the utility's electric power system, unless the utility determines that a restudy is not needed.

4. Unsubscribed Capacity

Utilities will continue to collect contributions from Participating Projects up to five (5) years after a Qualifying Upgrade is placed in service, or all available Hosting Capacity from a Qualifying Upgrade is used, whichever occurs first.

If the Triggering Project and initial Sharing Project(s) have met the minimum threshold to begin the upgrade, but the available Hosting Capacity has not been completely filled and thus utility customers contribute to the unassigned costs (either through the establishment of a deferred regulatory asset or in base rates), then any additional Sharing Projects that use available Hosting Capacity up to five (5) years after the upgraded asset is placed in service will be required to fund their pro rata share prior to interconnection, and utility customers shall receive the benefit provided by those additional Sharing Project(s). At the time additional Sharing Project(s) provide contributions for Qualifying Upgrades under this scenario, the following utility customer protections shall apply:

i. For Qualifying Upgrades that are in service but NOT included in base rates, the utility shall cease deferring the return on, and return of, investment associated with contributions from subsequent Sharing Projects. Additionally, the Qualifying Upgrade is to be excluded from the utility's net plant, or capital expenditure, tracking mechanism until it is included in base rates.

ii. For Qualifying Upgrades that are in service AND included in base rates, the utility is required to reduce plant in service by the funds provided by additional Sharing Project(s). The utility's net plant, or capital expenditure, tracking mechanism will provide utility customers with the benefit of funds received from the additional Sharing Project(s).

If the additional Hosting Capacity needs of the Triggering Project and initial Sharing Project(s) are below the minimum subscription threshold, and the Triggering Project and initial

Sharing Project(s) (if any), agree to fund shares beyond their capacity needs so that the minimum subscription threshold criterion is met, then the Triggering Project and initial Sharing Project(s) have provided contributions in excess of the Capacity Increase Shared Cost rate multiplied by their respective Hosting Capacity. Under this scenario the cost of unsubscribed capacity is being borne by the Triggering Project, previously paid Sharing Project(s) (if any), and utility customers.

Additional Sharing Projects that connect to the upgraded station/feeder will be required to contribute such that the Triggering Project, initial Sharing Project(s) (if any), and additional Sharing Projects have provided funding at an equal dollar per kW of Hosting Capacity. Triggering Projects and previously paid Participating Projects are to be provided refunds (from the utility) as a result of the additional contribution of Sharing Project(s). Refunds shall be provided to the Triggering Project and previously paid Sharing Project(s) until the Participating Projects have provided funding at a level that is equivalent to their Capacity Increase Shared Cost multiplied by their respective Hosting Capacity level. If additional Sharing Projects provide funding, the utility customer protections described in Scenario 1 (sections i and ii) shall apply.

5. Cost Reimbursement

The Utility will reimburse Participating Projects for the costs of Qualifying Upgrades in advance of the final project cost reconciliation process established in section 1.C, Step 11 of the SIR, as provided in this section. These reimbursements will be based on the cost estimates provided by the utility.

For upgrades involving the DG Encumbered Line mechanism, Triggering Projects and previously paid Sharing Projects shall be reimbursed by the utility when later Sharing Projects make their full payments, with contributions to be calculated based on project size and footage utilized. Once the Triggering Project and Sharing Project(s) have paid 100% of their respective payments, the utility will reimburse Sharing Projects' estimated costs to the Triggering Project within sixty (60) Business Days. When the final utility costs for all participating projects on a DG Encumbered Line are known, both the Triggering Project and any Sharing Projects will be billed or refunded by the utility as provided in the SIR.

When any Triggering Project or Sharing Projects pay more than their pro rate cost shares in order to reach a mobilization threshold, as provided in section D.3 above, payments from additional Sharing Projects received after the mobilization threshold is reached will be first applied to the Triggering Project and initial Sharing Project(s) that paid more than their pro rata cost share, until the Triggering Project and Sharing Projects' contributions are equal to the pro rata share of each project based on capacity needs. When the final costs are known, the Triggering Project and Sharing Projects will be billed or refunded based on the actual costs per the SIR. Applications held in the interim queues pursuant to the Commission's March 21, 2021 Order Directing Interim Modifications to the New York State Standardized Interconnection Requirements that pay the full cost of a Qualifying Upgrade shall treated as Triggering Projects and shall be reimbursed in accordance with the rules stated in the preceding paragraph.

APPENDIX G REDLINE

APPENDIX G -

APPLICATION SCREENING

PRELIMINARY SCREENING

All Preliminary Screens shall be completed by the utility and results shall be provided to the applicant in accordance with Section C, Step 4.

Screen A: Is the PCC on a Networked Secondary System?

Does the proposed system connect to a secondary network system?

- Yes (Proceed to Screen B, then complete Screens 1 through 3)
- No (Proceed to Screen B, then complete Screens C through F)

Screen B: Is Certified Equipment Used?

Does the applicant propose to use equipment that has been listed to meet UL 1741 (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) and for inverter-based equipment, UL 1741, including supplement B (UL 1741 SB), , with settings as specified in the utility's technical requirements document , by a nationally recognized testing laboratory?

- Yes (Pass Screen)
- No (Fail Screen)

Screen 1: Are the existing service, transformer, and network protector(s) adequate?

- Yes (Pass Screen)
- No (Fail Screen)

Are the existing service, transformer (*i.e.*, transformer closest to PCC), and network protector(s) adequate to interconnect the aggregate and proposed DER capacity (inclusive of this proposed project)?

- Yes (Pass Screen)
- No (Fail Screen)

Screen 2: Is the proposed DG system compatible with the utility grid?

2(a) Identify the equipment type (inverter, synchronous, induction, or hybrid) and capacity (kW).

2(b) Can the network protector(s) accommodate reverse power?

- If answer to Items 2(a) and 2(b) Pass (Pass Screen)
- If answer to Item 2(a) or 2(b) Fails (Fail Screen)

Screen 3: Simplified Penetration Test

3(a) Is the aggregate interconnected and proposed DER capacity (including this proposed project) less than 15% of the minimum load of the network?

3(b) Is the sum of the aggregate interconnected and proposed DER capacity (inclusive of this proposed project) in the local network less than 50% of the minimum load on the transformer(s) in this area?

- If answer to Items 3(a) and 3(b) is Yes (Pass Screen)
- If answer to Item 3(a) or 3(b) is No (Fail Screen)

Screen C: Is the Electric Power System (EPS) Rating Exceeded?

Does the maximum aggregated generation or loading capacity connected to an EPS (existing and approved prior to application) exceed any EPS ratings (modified per established utility practice)?

- Yes (Fail Screen)
- No (Pass Screen)

Screen D: Is the Line and Grounding Configuration Compatible with the Interconnection Type?

1. Identify primary distribution line configuration that will serve the distributed generation or energy storage. Based on the DER interconnection and using the table below, determine compatibility with the electric power service, including, phase balance, line and grounding configuration. The following table shall be used to determine risk for ineffective grounding

Primary distribution line configuration	**Type of DER connection to primary**	**Result/Criteria**
Three-phase, three-wire	Any type	Pass
Three-phase, four-wire > 5 kV	Single-phase line-to-neutral	Pass
All Three-phase, four-wire (For any line that has sections or mixed three-wire and four-wire)	All others	Fail. To pass aggregate DER AC nameplate rating must be less than or equal to 10% of line-section peak load

2. Based on aggregate DER on the feeder, is phase balancing maintained within utility limits?
   - If items 1 & 2 pass, (Pass Screen)
   - If items 1 or 2 fail, (Fail Screen)

Screen E: Simplified Penetration Test

If the aggregate DER capacity on any medium voltage line section (existing and approved prior to application) is less than the daytime minimum load (where 12 months of line section minimum load data are available or alternatively can be calculated, ~~can be~~ estimated from existing data, or determined from a power flow model) or 15% of the annual peak load (where daytime minimum load data is not available) for all line sections bounded by automatic sectionalizing devices upstream of the DER?

- Yes (Pass Screen)
- No (Fail Screen)

Screen F: Is Feeder Capacity Adequate for Individual and Aggregate DER?

1. Is the feeder available short circuit capacity at the medium voltage PCC, divided by the rating of the individual DER, greater than 25?
2. Is the feeder available short circuit capacity at the substation divided by the capacity all aggregate DER on the feeder, greater than 25?
   - If items 1 & 2 pass, (Pass Screen)
   - If items 1 or 2 fail, (Fail Screen)

SUPPLEMENTAL SCREENING ANALYSIS

All Supplemental Screens (G-I) shall be completed by the utility and results shall be provided to the applicant in accordance with Section C, Step 4.

Screen G: ~~Supplemental Penetration~~ Reverse Power Flow Test

~~Where 12 months of line section minimum load data are available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate DER capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the DER? Note the calculation of minimum load should consider both generation and charging modes of DER when energy storage is involved. Both generation and load limits need to be considered.~~
Where the aggregate DER capacity exceeds the minimum load for all line sections bounded by upstream equipment, does the EPS have the capability to support reverse power flow?

- Yes (Pass Screen)
- No (Fail Screen)

Screen H: Voltage Flicker Test

Can it be determined that the voltage fluctuation is within acceptable limits as defined by IEEE 1453?

1. Voltage flicker emission generated by each fluctuating installation (Pst) should be calculated using the following formula:

$$\Delta V = \left(\frac{d}{d_{P_{st=1}}}\right) \times F \leq 0.35 \; and \; d = \left(\frac{R_L \times \Delta P + X_L \times \Delta Q}{V^2}\right)$$

When: $\frac{X_L}{R_L} < 5$

OR

$$\Delta V = \left(\frac{d}{d_{P_{st=1}}}\right) \times F \leq 0.35 \; and \; d = \left(\frac{\Delta V}{V}\right) \approx \frac{\Delta S}{S}$$

When: $\frac{X_L}{R_L} \geq 5$

Whereby:

$$PV\ Plant\ Variability = \left(\frac{F}{d_{P_{st=1}}}\right) = \frac{0.2}{2.56\%} = 7.8$$

Explanation of Variables & Acronyms
d *= the relative voltage change caused by the DER at the PCC*
dpst *= 1 (curve value) is the relative voltage change that yields a Pst value of unity when voltage fluctuations are rectangular*
Pst *= the short-term flicker emission limit for the customer installation (typically based on 10-minute time frame)*
X_L *= the line reactance in ohms*
R_L *= the line resistance in ohms*
Isc *= the maximum available 3-phase fault current at the PCC in amperes*
Ssc *= the maximum available fault apparent power at the PCC*
ΔS *= the change in apparent power in volt amperes*
ΔP *= the change in real power in watts of the DG*
ΔQ *= the change in reactive power in vars of the DG*
V *= the nominal line to line voltage*
ΔV *= the change in voltage at the PCC*
F *= the shape factor related to the shape of the expected voltage fluctuation*

2. Can it be determined within the Supplemental Review that aggregate DER does not cause voltage excursion outside of ANSI C84.1 Range A?
3. Can it be determined that an aggregate DER generation change of 75% of nameplate does not result in a voltage change of greater than half the bandwidth of any voltage regulating device on the associated feeder?

A Pst greater than 0.35 as calculated in Step 1 or no to the determination in Steps 2 and 3 constitutes failure of this screen.

Screen I: Operating Limits, Protection Adequacy and Coordination Evaluation

1. Review anti-islanding protection requirements based on the most recent version of the JU Unintentional Islanding Protection Practice and identify utility and DER system upgrades, if required.
2. Review DER system configuration to determine if design and operation meets utility's effective grounding and ground source contribution requirements.
3. Identify equipment where fault current exceeds 90% of its short circuit current interrupting capability.
4. Identify any additional concerns related to utility and DER protection adequacy and protection, including but not limited to: protective device coordination and coverage, load rejection overvoltage, and 3V0 protection (where applicable).

APPENDIX K REDLINE

APPENDIX K -

Energy Storage System (ESS) Application Requirements / System Operating Characteristics / Market Participation

Application Requirements

a. Provide a general overview / description and associated scope of work for the proposed project. Is the new ESS project associated with a new or existing DG facility? (if information is available). Use the example given below for the project description if information is available.

   Project consists of a new **AC-coupled hybrid** Distributed Generator (DG) and Energy Storage System (ESS). The proposed project is not associated with any other existing DER at the facility OR The proposed project is associated with project XYZ (provide project number from relevant utility's IOAP). The DG consists of a **2000 kW / 2000 kVA** solar PV system, and the ESS will be a single inverter **979.2 kW / 1000 kVA** with a **3916.8 kWh** rating. The required ESS charging capacity of our system will be **4189 kWh** factoring in round trip efficiency of **93.5%** and will charge from both the PV and the grid. The system will have an auxiliary load of **45 kVA**, and the itemized list will be included in the line diagram

b. Identify whether this is a Stand-Alone or Hybrid ESS proposal, or a change to the operating characteristics of an existing system. If Hybrid ESS, please select the configuration option:

   1. Hybrid Option A - ESS is charged exclusively by the DG

   2. Hybrid Option B - ESS will not export to the grid, only DG will.

   a. Hybrid Option C - ESS may charge/discharge unrestricted from the grid, but grid consumption by ESS is netted out of grid exports.[1]

   3. Hybrid Option D - ESS may charge/discharge unrestricted from the grid, but any consumption on the account is netted out of grid exports

   4. N/A - not Value Stack

c. Market participation:[2]

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[1] ESS may have restricted charge/discharge to be defined in Question 2e.

[2] Market participation information is non-binding but may be used to verify operating characteristics and metering configuration. Participation in NYISO markets and NWA programs may influence the technical study.

1. Compensated under a utility tariff(s)? If yes, please specify. Identify any associated use case stacking (*i.e.*, parallel standby, net meter, VDER, import only, export only, peak shaving, generator firming, demand response, etc.) if applicable.
2. NYISO markets? If yes, has the NYISO process been initiated? Please specify which anticipated NYISO market(s).
3. As part of an NWA? If yes, please specify which associated NWA.
4. program or market not listed? If yes, please describe.

d. Indicate ~~whether the ESS and DG system inverter(s)/converter(s) are DC-coupled or AC-coupled and provide the following~~: DER system nameplate rating based on the proposed project configuration, i.e., stand-alone, AC-coupled or DC- coupled. The values should be broken down by existing DER and DER to be installed in the DER Nameplate Rating table below. Also indicate the total exporting capacity and total importing capacity including all losses in the Storage Capacity Table.

1. ~~DER Nameplate Ratings:~~

   ~~i. Storage inverter rating (kW) for AC-coupled or stand-alone systems;~~

   ~~ii. DG inverter rating (kW) for AC-coupled systems (if DG present); or~~

   ~~iii. DG + ESS inverter rating (kW) for DC-coupled systems.~~

2. ~~Storage capacity (kWh)~~ ~~[3]~~

Table 1. DER Nameplate Rating

DER System		**Inverter Nameplate Rating**		**Factory Limited Nameplate Rating***	
		kW	**kVA**	**kW**	**kVa**
Stand-Alone	New Storage to be Installed				
	Existing Storage Installation if Applicable				
AC-Coupled System	New Storage to be Installed				
	Existing Storage Installation if Applicable				
	New DG to be Installed				
	Existing DG Installation if Applicable				
	New Storage and DG to be Installed				

~~[3] Kilowatt hour rating values are typically not utilized for impact review outside of a utility performance requirement under and NWA solution. However, kWh is required for utility reporting and is a mandatory date field.~~

DC-Coupled System	Existing DG and Storage Installation if Applicable				

* If the factory nameplate rating reflects system limitations, the equipment manufacturer shall additionally provide a letter verifying the factory limited reduced rating of the system before the utility can utilize the factory limited nameplate rating in the CESIR.

Table 2. Storage Capacity

Storage Capacity in kWh	
Total Export Capacity	
Total Import Capacity - Charging and Losses	
Round Trip Efficiency	

e. Provide specification data/rating sheets for both the AC and/or DC components including the manufacturer, model, and nameplate ratings (kW) of the inverter(s)/converters(s) and controllers for the ESS and/or DG system, and capacity of ESS unit(s) (kWh).

f. Indicate the type of Energy Storage (ES) technology to be used. For example, NaS, Dry Cell, PB-acid, Li-ion, vanadium flow, etc.

g. Will the proposed project provide both real power and reactive power (PQ injection)?

h. Will the proposed project provide reactive power control, either via volt/VAR mode or specific power factor?

i. Indicate whether the interconnected inverters inverter(s)/converter(s) is/are compliant to the latest versions of the following additional standards. If partially compliant to subsections of the latest standards, please list those subsections:

    1. IEEE 1547a – 2018
    2. UL 1741, including supplement B (UL 1741 SB) with settings as specified in the utility's technical requirements document.
    3. List the UL 1741 CRD for PCS, if this applies to the project. Also mention the certification tests that were performed and/or excluded for the proposed inverter.
    4. List the UL 1741 CRD for Multimode, if this applies to the project. Also mention the certification tests that were performed for the proposed inverter.

j. List the system's maximum import in kW AC, including any equipment and ancillary loads (*i.e.*, HVAC) to be installed to facilitate the ESS installation.

List the ancillary equipment's maximum import in kW and kVA for HVAC and other aggregated ancillary loads in the table below. Where data on ancillary equipment load is unavailable, please provide the best estimate.

Table 3. List of Ancillary Equipment and Load

Ancillary Equipment	**Ancillary Load**	
	kW	**kVA**

k. Indicate desired ramp rates in kW/second during charging and discharging (worst case will be assumed if not provided). Please attach a charge and discharge data/curve.

l. Is the ESS symmetrical or asymmetrical (*e.g*., charge magnitude equivalent to discharge magnitude)? Provide proposed inverter(s) power factor operating range and anticipated operational setpoints[4] in the context of the expected two-quadrant or four-quadrant operation.

m. Indicate the maximum potential change in power magnitude expressed in equipment limitations such as per-second, minute, hour, or day, and kW or % of kW as applicable.

~~n. Indicate any specific operational limitations that will be imposed (*e.g*., will not charge or discharge across PCC between 2-7 pm on weekdays; ESS will not charge at any time that would increase customers peak demand, etc.). Charge/discharge at any time (24 hours) will be assumed by the utility if not provided.~~

n. Add check boxes against the preferred charging and discharging windows in Table 5 below. For a 24/7 unrestricted schedule, check all boxes for charging and discharging windows. Where scheduled operation is selected, please ensure that the energy storage system's operation is aligned with the local utility's guidelines for charging and discharging. Be advised that the specific conditions and requirements of the local electrical circuit will be the determining factor for the final operational charge/discharge windows and rates. If not specified, the utility will prescribe operational windows based on the local utility's guidelines for scheduled operation. Also indicate any specific operational limitations that will be imposed (e.g., will not charge or discharge across PCC between 2-7 pm; etc.).

[4] Final setpoints are subject to change per utility's direction

Please indicate if the project should be studied for one or both scenarios.

Table 4. Preferred Study Operation Windows

Study Operation Windows	**Yes/No**
Preferred/selected operation window	
24/7 unrestricted operation	

If 24/7 unrestricted operation is not selected, please fill the table below. In the Capacity (kW) column, mention the fraction of battery nameplate capacity in whole numbers that will charge or discharge.

Table 5. 24/7 Charging and Discharging Schedule

Time of operation	**Charging**		**Discharging**	
	Check as applicable	**Capacity (kW)**	**Check as applicable**	**Capacity (kW)**
2400-0100	☐		☐	
0100-0200	☐		☐	
0200-0300	☐		☐	
0300-0400	☐		☐	
0400-0500	☐		☐	
0500-0600	☐		☐	
0600-0700	☐		☐	
0700-0800	☐		☐	
0800-0900	☐		☐	
0900-1000	☐		☐	
1000-1100	☐		☐	
1100-1200	☐		☐	
1200-1300	☐		☐	
1300-1400	☐		☐	
1400-1500	☐		☐	

1500-1600	☐		☐	
1600-1700	☐		☐	
1700-1800	☐		☐	
1800-1900	☐		☐	
1900-2000	☐		☐	
2000-2100	☐		☐	
2100-2200	☐		☐	
2200-2300	☐		☐	
2300-2400	☐		☐	

o. Provide a summary of protection and control scheme functionality and provide details of any integrated protection of control schematics and default settings within controllers.

p. Submit control schemes, electrical configurations, and sufficient details for the utility to review and confirm acceptance of proposal. Detail any integrated control scheme(s) that are included in the interconnected inverter(s)/converters including a sequence of operations for expected events, energy flows, or power restrictions. For example, provide details if the ESS can be charged only through the DG input, or if the ESS can be switched to be charged from the line input, or if a control scheme is proposed to prohibit power flow directionality or peak values. Provide details on grounding of the interconnected ESS and/or DG system to meet utility's effective grounding requirements.

q. Provide short circuit current capabilities and harmonic output from the hybrid ESS project or stand-alone ESS.

r. If the intended use case for the ESS includes behind-the-meter backup services, please provide a description and documentation illustrating how the entire system disconnects from the utility during an outage (*e.g.*, mechanical or electronic, coordination, etc.).

Optional Questions

Questions in this section are not required for a complete application, although any responses provided may support the utility's decision to review the project performance in a manner that could result in less impact to the customer interconnection.

a. Indicate whether the interconnected inverters inverter(s)/converter(s) is/are compliant to the latest versions of the following additional standards. If partially compliant to subsections of the latest standards, please list those subsections:
    a. SunSpec Common Smart Inverter Profile (CSIP) v2.103-15-2018

b. Any other recognized standard or practice. Indicate the maximum frequency of change in operating modes (*i.e.*, charging to discharging and vice-versa) that will be allowed based upon control system configurations.

c. Provide details on standard communication as follows:

    a. Hardware interfaces that are available, *e.g.*, TCP/IP, serial, etc.

    b. Protocols that are available, *e.g.*, MODBUS, DNP-3, 2030.5, etc.

    c. Data models that are available, *e.g.*, 61850-90-7, SunSpec, MESA, 2030.5, OpenADR, etc.

d. Provide details on whether the inverter(s)/converter(s) have any intrinsic grid support functions, such as autonomous or interactive voltage and frequency support. If so, please describe these functions and default settings