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Sep 16 2020

September 16, 2020

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Duke Energy Carolinas, LLC's, Duke Energy Progress, LLC's and Dominion Energy North Carolina's Storage Retrofit Stakeholder Meetings Report
Docket No. E-100, Sub 158

Dear Ms. Campbell:

Enclosed for filing in the above-referenced docket is Duke Energy Carolinas, LLC's, Duke Energy Progress, LLC's and Dominion Energy North Carolina's Storage Retrofit Stakeholder Meetings Report.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

cc: Parties of Record

Enclosure

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's, Duke Energy Progress, LLC's and Dominion Energy North Carolina's Storage Retrofit Stakeholder Meetings Report, in Docket No. E-100, Sub 158, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 16th day of September, 2020.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))))))))	**JOINT REPORT BY DUKE ENERGY CAROLINAS, LLC, DUKE ENERGY PROGRESS, LLC, AND DOMINION ENERGY NORTH CAROLINA ON STORAGE RETROFIT STAKEHOLDER MEETINGS**

NOW COME Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP", collectively, the "Companies" or "Duke Energy"), and Dominion Energy North Carolina ("DENC" and collectively with Duke Energy, the "Utilities") and, pursuant to the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* ("QFs") in this docket, report to the Commission on the results of the stakeholder process established to address the complexities of modifying existing facilities that request to add capacity through the co-location of batteries.

INTRODUCTION

In directing the formation of this stakeholder process, the Commission's goal was to create a forum to:

(a) identify critical issues that are barriers to the addition of energy storage to existing facilities;
(b) develop solutions that will encourage deployment of energy storage;
(c) further identify specific challenges that prevent the commercial viability; and
(d) provide certainty to QFs that are considering the addition of an energy storage component to their electric generating facilities.[1]

[1] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 158, April 15, 2020 ("Sub 158 Order") at 131.

The Commission further directed that "[t]he stakeholder process should be comprehensive in its consideration of all use cases for adding an energy storage component to a committed [qualifying facilities] QF's electric generating facility" and for the Companies (and DENC) to file a report on the process by no later than September 1, 2020. *Id*. The Commission outlined the categories that the report should address and stated that the report shall identify the areas of consensus reached on these categories by the stakeholders and, in the areas where the stakeholders fail to reach consensus, the Companies shall recommend a resolution.

BACKGROUND AND SUMMARY OF THE MEETINGS

Duke Energy hosted four virtual stakeholder meetings to address the Commission's request to convene a stakeholder group to further discuss issues and propose solutions to storage retrofit. The report that follows is the culmination of these stakeholder discussions.

Stakeholder meetings began virtually on May 13, 2020. Attendance was approximately 70 people at most in the meetings. The first meeting served as an introductory discussion and focused on the Commission's Sub 158 Order regarding storage retrofits. Prior to the meeting, Duke Energy requested that stakeholders submit a summary of their position on the various topics covered in the Sub 158 Order, and four stakeholders shared positions: the Public Staff, the Southern Alliance for Clean Energy ("SACE"), DENC, and the North Carolina Clean Energy Business Alliance ("NCCEBA"). The meeting also shared those overall comments, laid out the draft plan for how Duke Energy would move forward with meetings, and opened the discussion on AC and DC metering configurations with draft single-line diagrams provided by NCCEBA.

The second meeting, on June 10, 2020, delved into some of the commercial topics from the Sub 158 Order, including the existing terms and the potential for contracting for ancillary services, as well as more details and nuances of the technical questions and the issues of AC and DC metering. For this meeting, Duke Energy requested examples of single-line diagrams detailing AC and DC metering configurations, and NCCEBA provided example single-line diagrams, which were included in the presentation. In addition to AC metering and DC metering, two other suggestions were discussed for measuring the storage output (explained below after Figure 1): a DC "alternative measurement" that could theoretically use other sensors to calculate the output, and an estimation methodology. The stakeholders in the meeting generally agreed that these two concepts were not aligned with the billing practices called for in the terms and conditions applicable to the Commission-approved *pro forma* power purchase agreement ("PPA"), as well as would present challenges for auditing and verification of the output information. As such, the stakeholders did not pursue these options for retrofitted facilities in future discussions.

The third meeting was held on June 29, 2020, and covered more details of the commercial terms under the consensus that the retrofit storage would be part of the same QF as the original solar facility and would be subject to the amendments to N.C. Gen. Stat. § 62-156 made by House Bill ("HB") 589, specifically the amendments to N.C. Gen. Stat. § 62-156(b)(1) and (c), which provide that the standard contract for QFs up to and including 1 megawatts ("MW") is 10 years and that the rates paid by electric utilities to QFs not eligible for the standard contract are fixed for a five-year term. Here, Duke Energy provided examples of the appropriate fixed-price term of an amendment for storage based on the AC capacity of the original solar QF (which would determine the length of fixed-price terms according to HB 589). Stakeholders also discussed Duke Energy's interpretation of the Certificate of Public Convenience and Necessity ("CPCN") requirements under Commission Rule R8-64 and report of proposed construction ("ROPC") requirements under Commission Rule R8-65 for a storage retrofit to an existing QF solar site.

The fourth meeting was held on July 31, 2020 and touched on each of the topics listed in the Sub 158 Order and summarized Duke Energy's positions as well as the results and conclusions of the prior meetings on each topic. In addition, the topic of cost recovery of ancillary services provided by retrofit QF storage was also discussed.

Overall, it appeared (based on both stakeholder comments and the lack of comments on certain topics) that the stakeholder process achieved much agreement across the topics, with exceptions noted in the specific topics below.

CATEGORIES TO BE ADDRESSED

I. Technology

(a) Identify the metering challenges for AC and DC measured systems.

Before detailing the metering challenges, it is useful to understand the possible locations for storage to be added to an existing solar facility and the pros and cons of each. Generally, the storage can either be connected "behind" the inverter(s) on the DC side or "in front of" the inverter(s) on the AC side (but before the point of interconnection). Both options have benefits and challenges.

DC connection may be preferable to fully capture the "clipped" energy and essentially to be able to export more kWh and increase the facility's overall capacity factor. Clipped energy refers to power that is generated but does not make it to the grid for export. This could be DC power that is "clipped" because the inverter is already maxed out (due to more DC power capacity than AC inverter capacity) or there is not enough DC power being produced to activate the inverter to produce AC energy (for example, when the sun is first rising and when it is about to set). One potential obstacle of DC-connected storage is that many solar facilities have multiple inverters, and the storage would have to be behind each inverter to capture the clipped energy of the portion of the solar behind that inverter, resulting in multiple energy storage devices (one per inverter). This means that the site would also have to have the physical space to create a pad mount and container in which to house the energy storage and connect it on that side of the inverter. This may add complexity to adding the DC-connected energy storage, when the original site was not designed with that space consideration. To bifurcate the storage and solar energy, there would have to be a DC meter on each energy storage device, as well.

AC connection of retrofit storage may be able to capture some clipped energy from the peak generation, though. Some solar facilities have inverters that are over-sized; thus, some of the clipped energy from peak production may still be captured in an AC-connected configuration. Only one connection would need to be made, and only one energy storage system would be needed to capture energy from across all the solar inverters. This configuration will have additional losses, however, as there will be an extra conversion step required, to convert the energy from DC to AC then back to DC.

If storage is connected on the AC side of the solar inverters, then there are additional concerns about how much the facility would be capable of exporting to the grid. The two main issues are that 1) the AC-connected battery would be capable of also charging off the grid and 2) the facility would be capable of outputting the full capacity of solar *plus* the full capacity of the battery (for example, if there are 5 MW of solar panels and 2 MW of battery, this facility could technically output 7 MW). Participants agreed that these issues could be addressed through existing means at the facility, such as the plant controller, or through the programming of the interconnected utility's existing electronic reclosers to prevent the facility from charging from the grid or exceeding the output limits specified in the interconnection agreement, as discussed later in this report.

If the battery charges from the grid, however, another interconnection study would have to be performed to study the storage as load and not just as generation.

Metering Considerations

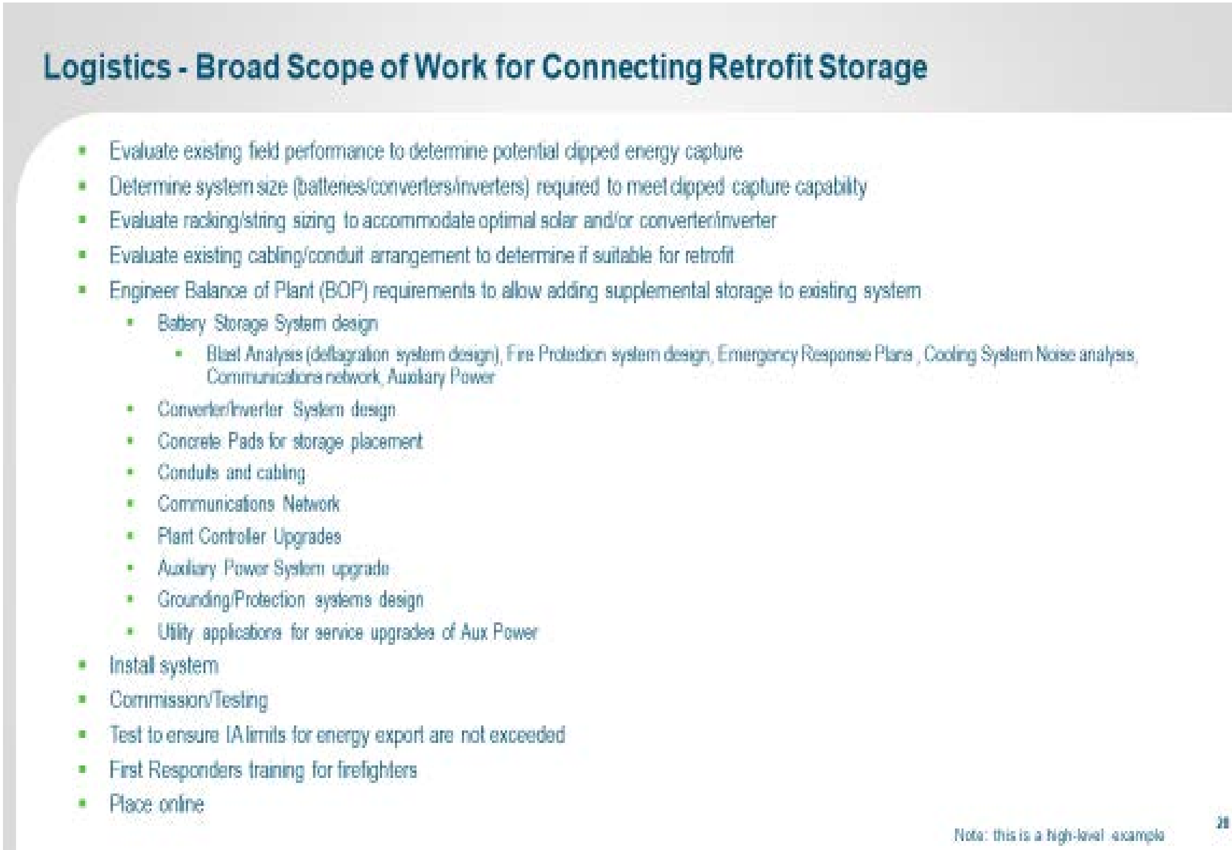
A compelling argument for AC connection is the existing Duke Energy and DENC metering: all the Utilities' metering today is through AC revenue-grade meters, and these existing meters are already integrated into the billing system. To separately measure the solar output from the storage output, a separate AC meter could be connected to the output of the battery. This meter would track the battery export and could be subtracted from the full facility export (which is the existing AC meter) to calculate the solar production separately. The non-storage related solar output would continue to be paid according to its existing PPA rate and the battery output would be on the corresponding, most recently-approved biennial Avoided Cost standard offer rates or Avoided Cost rates calculated from the most recently approved biennial Avoided Cost rate methodology rates.

For DC-connected systems, a DC meter would be required to measure the energy coming out of the battery before it goes through the inverter. Then storage output would have to be subtracted from the total facility output (measured with the existing AC meter), with some type of accounting for losses, potentially established in a baseline field test, to account for the storage energy as it passes through the inverter. This subtraction would deduce the solar output separate from the storage output.

The major obstacle with this metering approach is that although there are many DC meters in the market today, there are no certified "revenue grade" DC meters, because the American National Standards Institute ("ANSI") standard C12.32 to determine how a DC meter is gauged for accuracy and calibrated is in development and not yet approved. Therefore, the standards for validating the accuracy of a DC meter have not been established. There is an EMerge Alliance task force, chaired by Duke Energy, that is working closely with ANSI, NEMA, NIST, SCE, SRP, Xcel, Ercot, Radian Research, Powertech Labs, Sensus, Accuenergy, Measurlogic, Aclara, Comcast, Nextek Power, Watthour Engineering, and many other companies to develop the ANSI C12.32 standard. DENC is in the process of joining the EMerge Alliance task force. The goal of the task force is to complete a draft of the standard for ANSI / NEMA and public review in the Fall of 2020. A review and commenting period will likely take several months and conclude with a vote for ratification in early 2021. Once C12.32 is approved, the DC meter manufacturers and test labs can begin to produce meters that meet these specifications, as well as produce test equipment for utilities and other consumers of these meters to test the meters for accuracy, durability, and other aspects. Once the DC meters and test equipment are available, the Utilities can test this new piece of equipment as they would any other new piece of equipment to move it to a list of approved equipment, for the utility's use. These DC meters must also be able to capture and deliver data in a way that is compatible with the current billing systems. Meeting that requirement will likely fall to the metering manufacturers. However, manufacturers already make AC meters that are designed to integrate with various billing systems; thus, this consideration of billing integration is likely expected. Revenue-grade DC meters are clearly on the horizon, but the timing of their availability is uncertain. If ANSI quickly approves the new standard, and the manufacturers then quickly begin to produce meters that meet the specifications and align with current billing systems, revenue-grade DC meters may be available as early as 2022. This further supports the Utilities' determination that at this time DC-connected energy storage is not a readily available option.

The single-line diagrams in the attached Exhibit A, provided by NCCEBA, illustrate some of the differences between retrofitting energy storage to an existing solar facility on the AC side of the inverters versus the DC side of the inverters.

The stakeholders also considered that any retrofit installation of storage will require work, and some of the pieces of work will be required *per battery* rather than per facility. A DC-connected option may require many battery installations because there would be one battery per inverter. Thus, logistical reasons may persuade a developer to opt for AC-connected storage. The slide from the June stakeholder meeting illustrating many of the steps in the scope of work is below.



(b) Propose solutions for AC and DC measured systems.

For AC-connected systems:

To prevent the retrofit storage from charging from the grid, the first mechanism for protection is a plant-level controller programmed to prevent this. As a backup protection, the utility recloser should also be programmed to disconnect the QF facility from the grid if the load exceeds the typical auxiliary load. Similarly, to prevent output to the grid in excess of the maximum generating capacity established in the original interconnection agreement maximum, the solar and storage combined energy output will have to be managed by a plant-level controller and, as backup protection, the utility recloser should also be programmed to disconnect the QF facility from the grid if output exceeds the maximum generating capacity established in the original interconnection agreement. Duke Energy is now auditing solar QF facilities to ensure they do not over-export and will follow the same guidelines to audit solar facilities that add storage, as well. DENC will need to conduct additional study to determine how to install directional protection settings on a point of interconnection recloser, and to evaluate the ability to differentiate energy delivered to the QF for station service from any charging from the grid.

As explained in Duke Energy's August 14, 2020 letter in Docket No. E-100, Sub 101, Duke Energy's streamlined process for the interconnection study of ESS retrofits previously proposed in Docket No. E-100, Sub 101 was designed for DC-connected ESS. Pending a Commission decision in this docket, Duke Energy will update its waiver request in Docket No. E-100, Sub 101 to specify the streamlined interconnection study requirements that will be applicable to AC-connected ESS retrofits. AC-connected storage on the distribution system will be eligible for the streamlined interconnection review process, but storage retrofits on the transmission system will require additional study. In Docket No. E-100, Sub 101, Duke Energy created a screening process for DC-connected retrofit storage that only exports 9 AM to 5 PM (among other requirements) and created another review process for DC-connected storage that would export outside of those hours (among other requirements). AC-connected storage retrofit distribution projects will not be eligible for the screening process for only 9 AM to 5 PM export because AC-connected storage involves different protections to ensure export does not exceed the designated maximum. AC-connected storage can be eligible for the latter review process, though. The likely criteria to be eligible for the streamlined process for distribution-connected projects will include the following: (i) ESS not charged from the grid, (ii) upgrade to the latest point of interconnection standards as applicable (which could include an updated recloser, battery energy storage template, and/or telemetry) and (iii) the QF will undergo an inspection by Advanced Energy. The costs of these interconnection requirements will vary considerably between sites depending on the existing equipment.

For DC-connected systems:

Although the Utilities believe this can be a feasible future approach, it will take time and is not an immediate-term solution to measuring storage output separate from solar output in a way that meets the metering accuracy standards currently set forth in Commission Rule R8-12. This approach will likely require review of, and revisions to, Commission Rules R8-9 through R8-14, as it would rely upon measuring equipment and estimation methods that are not currently utilized by Duke Energy nor approved by the Commission.

As mentioned above in the "Background" section, Duke Energy shared a table in the second stakeholder meeting to summarize the ideas shared for approaches of measuring storage output separate from solar. The table categorized some of the considerations of measurement including, for each option discussed, whether it is already operational, the difficulties in data collection and billing, the equipment costs, interconnection implications, and whether that method was already permissible by the Commission. The following table indicates initial impressions in each of these categories that were used for discussion purposes, and ultimately the bottom two rows were not pursued based on direction from the stakeholders in the meeting.

Type	Does this pathway exist already?	Difficulty/cost of data collection and billing	Equipment Cost	Interconnection	Permissible by NCUC?
AC meters	Yes (with some billing adjustments)	Low	Low	Likely a way to develop screens for streamlined process for distribution AC projects. Transmission will require full study.	Yes
DC (revenue grade) meters	No	Once revenue grade meters are established, Low	Presumably close to AC costs; will have more installs per site.	DC-connected already has a streamlined process.	Yes, after revenue grade meters are available
DC alternative measurement	No	High	High (How is calibration done? What is that cost?)	DC-connected already has a streamlined process.	Not currently – calculation method is unclear
Estimation	Not in this way, and not without validation and true-ups	High	For onsite meters, none. For billing process changes, maybe high	Answers above (could be either AC or DC)	Not currently without true-ups

From the stakeholder discussion, the group agreed that the benefit of AC meters is that they are a known and available equipment that can integrate with the Utilities' billing systems. They have better-understood installation needs and costs (given the new configuration, there will still be some learnings), and this mechanism is permissible by the Commission Rules.[2] For the "streamlined" storage retrofit process, Duke Energy was willing to define the requirements and amend the filing to include distribution AC-connected storage, as well.

Developers remain interested in using certified DC-revenue grade meters, but the major obstacle is that they are not yet available in the market. Once the standards and technology are established and approved, however, this method of measurement seems a plausible option.

(c) Analyze cost of design and implementation for both the facility and utility.

[2] *See* Commission Rules R8-9 through R8-14.

The numbers shown below are rough estimates prepared by Duke Energy. After several meter installations for retrofit storage are complete, Duke Energy would be able to provide numbers with higher confidence. The interconnection facility retrofit costs will vary by site, as well, and these estimates do not include any interconnection costs. In addition, the cost to retrofit an interconnection facility may also include monthly O&M charges. For a general idea, however, Duke Energy has estimated these numbers. For distribution-connected solar sites metered at the point of interconnection:

<u>AC-connected systems</u>:

For a typical pole mount AC meter system, Duke estimates the costs as:

(3) 200:5 HAER CTs (High Accuracy Extended-Range current transformers): $2,500
(3) 120:1 PTs (Potential Transformers, aka voltage transformers): $3,800
(1) 3PH AL form (metal bracket that holds metering transformers): $270
(1) Meter enclosure: $170
(1) Mid - Tier) meter: $380
(1) RV-50X cell unit (the current modem type Duke uses): $900
Installation Labor: ~$1,000

Total: ~ $9,000 (“loaded”, which is with installation labor which can vary)

For a typical pad mount (deadfront) AC meter installation, Duke estimates the costs as:

(3) 200:5 HAER CTs (High Accuracy Extended-Range current transformers): $2,500
(3) 120:1 PTs (Potential Transformers, aka voltage transformers): $3,800
(1) Primary Pad mount Enclosure (Deadfront): $4,000-$6,000
(1) Meter enclosure: $170
(1) Mid - Tier meter: $380
(1) RV-50X cell unit (the current modem type Duke uses): $900
Installation Labor: $1650

Total: ~ $13,400-$15,400 (“loaded”, which is with installation labor which can vary)

DENC estimates the following costs for pole mount and pad mount systems.[3]

[3] The cost differences from Duke Energy’s estimates are due to DENC metering at 34,500V compared to Duke Energy metering at 25,000V, and DENC uses a “High – Tier” meter for these installations. For

Pole mount Installation

(3) 200:5 HAER CTs (High Accuracy Extended-Range current transformers): $5,800
(3) 20125:115 PTs (Potential Transformers, aka voltage transformers): $7,200
(1) 3PH AL form (metal bracket that holds metering transformers): $370
(1) Meter enclosure: $350
(1) High - Tier meter: $2,500
(1) Cell Unit (the current modem type Dominion uses): $900
Installation Labor: ~$1,000

Total: ~ $18,120 ("loaded", which is with installation labor which can vary)

Pad mount Installation

(3) 200:5 HAER CTs (High Accuracy Extended-Range current transformers): $5,800
(3) 20125:115 PTs (Potential Transformers, aka voltage transformers): $7,200
(1) Primary Pad mount Enclosure (Deadfront): $15,000
(1) Meter enclosure: $350
(1) High - Tier meter: $2,500
(1) Cell Unit (the current modem type Dominion uses): $900 (915.66)
Installation Labor: $1650

Total: ~$33,400 ("loaded", which is with installation labor which can vary)

DC-connected systems:

Given that there are not currently revenue-grade DC meters, estimating what the meter cost will be when it is available is difficult. DC meters will also need to be installed behind each inverter, so the following estimates will be per DC meter, and there could be many. The interconnection facility retrofit costs will vary by site, as well, and these estimates do not include any interconnection costs. For a future revenue-grade DC meter system for distribution-connected solar sites metered at the point of interconnection, Duke Energy has made the following estimates:

ease of reference and for purposes of illustration, DENC used the same projected labor costs as Duke Energy.

DC Meter (0.5% accuracy): $500
Current Shunt: $80
Enclosure: $450
RV-50X cell unit (the current modem type Duke Energy uses): $900
(2) Fuses: $250
Installation Labor: ~$1,000

Total: ~ $3,200 ("loaded", which is with installation labor which can vary - <u>times the number of DC meters installed</u>)
(note: Billing integration costs unknown)

Many older 5 MW solar QFs have three inverters, but facilities with newer "string" inverters may have as many as five or six inverters per MW. Although the costs of a single DC meter configuration may at first appear lower than AC, the overall facility cost is likely comparable to or possibly exceeds AC.

(d) Identify and quantify specific ancillary services that can be provided by QFs coupled with energy storage.

The only specific ancillary services that can be provided by QFs coupled with energy storage that have currently been quantified and valued by Duke Energy, and approved for Avoided Costs purposes, are those that were established in the Astrapé study to value the Solar Integration Service Charge ("SISC"). These incremental costs of regulation and balancing are required to meet variable output from increased solar on the system and were calculated to be $1.10/MWh for DEC and $2.39/MWh for DEP in the Sub 158 Order. Solar facilities that came online or established a legally enforceable obligation prior to Sub 158 (November 1, 2018) do not incur the SISC, as they are grandfathered in. However, to the extent that storage retrofits smooth the output of the co-located solar, they could be eligible to earn this same value of SISC, as they are essentially helping to avoid the inefficient fuel use of ancillaries required by variable output.

Providing smoothing by use of the co-located storage may not require any additional equipment but will depend on the individual site's existing plant-level controller (also called the "power plant controller" or "plant master controller"). Duke Energy believes that the SISC avoidance protocols (to show evidence that smoothing has been achieved) would apply to a storage retrofit.

At this time, and as noted above, other ancillary services provided by solar QFs retrofitted with storage cannot be quantified or valued outside of those included in the Astrapé study due to a variety of technical, commercial, and regulatory hurdles. For similar reasons, DENC has not at this time identified any ancillary services that a QF with retrofit storage could provide to DENC. DEC and DEP recognize that the Commission is interested in exploring ancillary services further in the next Avoided Cost proceeding. Therefore, the Utilities respectfully submit additional exploration of ancillary services may be appropriate in other dockets and Commission proceedings.

II. Commercial

(a) Report on what existing commercial terms and conditions are preventive barriers for implementation.

The Commission approved certain terms and conditions for the Duke Energy standard offer in the Sub 158 Order that related to a Material Alteration.[4] The Companies have generally identified, however, the existing terms and conditions that would need to be addressed for implementation of retrofitting QFs with storage:

- **<u>Interconnection Agreement</u>:** The addition of Storage or an increase in DC- or AC-rated capacity would constitute a Material Modification of the approved interconnected Generating Facility and would require Duke Energy's review and consent under the Interconnection Agreement ("IA").

[4] Sub 158 Order at 129.

- **<u>Certificate of Public Convenience and Necessity</u>:** The addition of Storage or an increase in the DC or AC capacity of the facility would require written notice to the North Carolina Utilities Commission ("NCUC") in connection with the applicable CPCN. Duke Energy and the other stakeholders, however, appear to have agreed that written notice updating the CPCN or Report of Proposed Construction under Commission Rule R8-64 and R8-65 will address that commercial barrier.

- **<u>FERC Qualifying Facility</u>:** The addition of Storage or an increase in the DC- or AC-rated capacity may require QF re-certification with the Federal Energy Regulatory Commission ("FERC").

- **<u>Existing Executory PPAs</u>**: The description of the Facility from which Duke Energy is contracting to purchase the output is a material term of the PPA. Once executed, a material term of a contract may not be modified except by mutual agreement of all the parties thereto. Therefore, under the PPA (standard and negotiated) the addition of storage would constitute a material change to the existing facility and would require Duke's Energy's consent.[5] The stakeholders did not recommend any changes to the contract language. Instead, the addition of storage shall be accommodated by amending the existing PPA to: 1) revise the description of the Facility to include storage, 2) add a contract price applicable to the output from the storage device, and 3) address any operational or metering concerns associated with the addition of storage or other changes mutually agreed by the parties. Except as modified in the amendment all remaining terms of the contract (including the term) will remain unchanged. The parties to the stakeholder process explored several of the issues that would need to be addressed in the amendment.

DENC agrees that the items identified above would need to be addressed for implementation of retrofitting QFs with storage to its standard offer terms and conditions.

(b) Propose solutions to remove or mitigate preventive barriers.

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[5] *Id*.

As discussed above, establishing the retrofit storage terms and conditions as an amendment to the PPA will permit the addition of storage while preserving the original terms of the PPA that are not affected by the addition. For the Utilities to consent to changing the amendment, they would have to address all the issues above.

As described in its August 14, 2020, letter in Docket No. E-100, Sub 101, Duke Energy is also willing to amend the recent storage retrofit streamlined interconnection process to include a pathway for AC-connected storage on the distribution system, which is in addition to the DC-connected process that was already filed.

(c) Report on how to accomplish billing and payment for separately metered systems.

With the AC-connected meter configuration (adding another AC meter specifically to the storage output), the Utilities should be able to integrate both meters' data fields into the billing system. If the added AC meter for the storage output (behind the existing facility meter) is a type and register setup that is part of the Utilities' existing inventory, no additional work is anticipated to set up the meter.

Two AC meters will be required since the existing Purchase Power installation will be paid at a different rate than the newly installed battery storage. The billing system should be able to subtract the storage meter from the whole-facility meter to calculate the solar output and then apply the appropriate rates to the storage output and the solar output. Some set-up work will be required establish the calculation in the billing system, but it does appear the billing system has this capability.

When a certified revenue-grade DC meter is available, it would also have to be compatible and integrate with the Utilities' billing systems, as well. There would be some conversion calculated for changing the DC to AC current and accounting for conversion losses, since the Utilities issue payments and bills based on kWh AC.

III. Regulatory

(a) Identify and propose solutions to regulatory barriers, including without limitation whether the addition of energy storage to an existing QF requires an amendment to the QF's CPCN or a wholly separate CPCN for the energy storage facility.

For facilities under 2 MW, Commission Rule R8-65 requires the owner of an electric generating facility to file a report of proposed construction. For facilities greater than 2 MW, Commission Rule R8-64 requires the owner of a facility to file for a CPCN. According to Commission Rule R8-64(d)(3), CPCN holders must advise both the Commission and the utility to which the generating facility is or will be interconnected of any significant changes in the information set forth in subsections (b)(1) thru (b)(5) of that Rule. According to Commission Rule R8-65(g)(4), each facility owner must advise both the Commission and the utility to which the generating facility is or will be interconnected of any significant changes in the information set forth in subjection (g) of that Commission Rule. Given these Commission Rules, the Utilities support a filing update (a notification of an alteration) when retrofit storage is added to a CPCN or Report of Proposed Construction, but it appeared that the stakeholders reached consensus that the addition of storage does not result in the need for a new CPCN application or additional Commission rulemaking.

(b) Propose the appropriate Avoided Cost rates and terms of the PPA applicable to the energy storage element of an existing QF coupled with energy storage.

Duke Energy and the Public Staff of the North Carolina Utilities Commission ("Public Staff") interpreted the existing commercial terms and conditions for retrofit storage to be as they are defined for QFs under HB 589's amendments to N.C. Gen. Stat. § 62-156(b) and (c). The pre-existing solar facility PPA defines the maximum capacity of the facility and therefore determines the retrofit storage's eligibility of the fixed-price term for the energy produced from the battery. The retrofit storage is eligible for a fixed price that is the lesser of that term or the remaining term of the solar contract. The Utilities view this as a compromise if the retrofitted QF continues to be limited to the MW output that was originally contemplated in the PPA. Instead of nullifying the existing solar contract, the Utilities are willing to amend the existing solar PPA to add a new rate and term for the retrofit storage. The eligibility would be as follows:

Existing Solar PPA Max MW	**Storage MW**	**Years left in solar contract**	**Fixed rate available for storage is**
1	1	12 years	10 years
1	1	8 years	8 years
5	1	12 years	5 years
5	1	8 years	5 years
5	2	12 years	5 years
5	2	8 years	5 years
5	2	4 years	4 years
80	1	12 years	5 years
80	1	8 years	5 years
80	1	4 years	4 years
80	40	12 years	5 years
80	40	8 years	5 years
80	40	4 years	4 years

A similar chart appeared in a slide from a stakeholder meeting to illustrate that the existing PPA set the capacity of the facility, and the fixed-price term of the retrofit storage would be determined by the lesser of the solar PPA term or the eligible term as per HB 589 facility capacity.

For a generation facility that is 1 MW or less, the retrofit storage would be eligible to a fixed-rate term of the lesser of 10 years or the remaining life of the solar PPA. In the example above, the Sub 158 ten-year Avoided Cost rate would be used unless the solar PPA has less than ten years left, in which case Duke Energy or DENC as appropriate would calculate an Avoided Cost rate under the most recently approved standard offer methodology, based on the number of years left.

For a generation facility that is more than 1 MW, the retrofit storage would not qualify for the "standard" contract and would be eligible for what is referred to as a "negotiated" contract as described under N.C. Gen. Stat. § 62-156(c): to a fixed rate term of the lesser of 5 years or the remaining life of the solar PPA. The most recently approved Avoided Cost methodology would be used to calculate a five-year Avoided Cost Rate unless the solar PPA has less than five years left, in which case Duke Energy or DENC as appropriate would calculate an Avoided Cost rate based on the number of years left in the solar PPA under the most recently approved Avoided Cost methodology.

The Utilities propose the retrofit storage be added as an amendment to the existing solar contract, and not as a separate contract altogether (as noted earlier). The amendment would permit the existing facility to be modified to add storage under the condition that the output from the storage will be subject to a separate fixed-price term based on current methodology. Therefore, while the amendment would expire at the same time as the existing contract, the duration of the fixed price for the battery energy is limited by HB 589.

At the end of the fixed-price term applicable to the storage resource, the rate calculation will be refreshed based on the then-applicable methodology until the end of the contract term.[6] In no event shall the contract price applicable to storage be fixed for a term longer than: for facilities less than or equal to 1 MW: 10 years; for facilities greater than 1 MW: 5 years. Upon expiration of the PPA (as amended) the QF would be free to seek a new PPA for both the solar and storage together and would not need a bifurcated rate.

Per HB 589, once a utility has standard contract PPAs in aggregate of 100 MW or more (with a legally established obligation ("LEO") after Nov 2016), eligibility for the standard contract is reduced to 100 kW. Retrofit storage would not count toward the 100 MW aggregate capacity. However, once the eligibility threshold for standard contract terms is reduced to 100 kW, it will also apply to retrofit storage.

Not all stakeholders agreed with Duke Energy's and the Public Staff's interpretation of the applicable length of the fixed-price term for a storage retrofit amendment, including NCCEBA. NCCEBA, SACE, and NCSEA provided comments to Duke Energy suggesting that the storage retrofit should be eligible for a fixed-price term extending to the length of the remaining solar contract (which could be as many as 15 years). Duke Energy and the Public Staff did not agree with this approach given that the intention of the standard and non-standard ("negotiated") contract terms of HB 589

[6] This concept is similar to the Avoided Cost bill credit methodology approved by the Commission in its February 1, 2019 *Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments* in Docket Nos. E-2, Sub 1170 and E-7, Sub 1169.

were intended to limit the term of the fixed price to reduce the risk that the ratepayers would overpay for power from QFs, so this remained an area without consensus. DENC agrees with Duke Energy's position on this matter. Consistent with the Commission's Sub 158 Order, which directs the Utilities to recommend a resolution where the stakeholders fail to reach consensus, the Utilities recommend that the Commission adopt the proposal supported by the Utilities and the Public Staff, as described above. This recommendation follows the intent of the General Assembly in enacting HB 589, which was, in part, to limit the risk of overpayment by customers for QF power through long-term fixed rates.

(c) Propose how costs should be recovered (or payment made) for identifiable and quantifiable specific ancillary services provided by the QF coupled with energy storage.

Duke Energy proposes that for storage retrofits to an existing solar QF, the regulation and balance ancillary services for offsetting solar volatility, as calculated in the SISC are the only quantified ancillary services eligible for payment. The QF could use the battery to smooth the on-site solar generation output to earn the SISC (which was established in Sub 158). Because the facility is a QF, based on PURPA definitions, it would therefore meet the qualifications for recovery through the fuel clause. In North Carolina, Duke Energy may recover avoided energy and capacity costs from a QF through the fuel clause, and the smoothing of the output enables Duke Energy to use less fuel than it otherwise would if not for the battery.

The SISC was designed as an adjustment to the Avoided Cost value because the value of the energy and capacity provided from the solar resource was lower due to its intermittency. In a facility that retrofits storage, the existing solar is not subject to the

SISC under its current contract, but it can use the retrofit storage to smooth the solar output, and thereby earn the SISC in addition to the incremental energy/capacity value from the battery output. When viewed from an incremental perspective, the storage retrofit device creates capacity and energy value per the Sub 158 rate and potentially can create SISC value if used to smooth the co-located solar output.

(d) <u>The FERC's Broadview Solar Decision</u>

The retrofit stakeholder meetings concluded before the FERC's Broadview Solar decision issued on September 1, 2020,[7] but the Broadview decision has potential implications for both the work of this stakeholder group and future Commission PURPA proceedings, as well as other renewable energy policy issues such as Competitive Procurement of Renewable Energy and Green Source Advantage implementation. Briefly, the Broadview Solar decision concerned an application with the FERC by Broadview Solar, LLC ("Broadview"), seeking recertification as a small power production QF pursuant to PURPA and 18 CFR 292.207(b), for a combined solar PV and battery storage facility. Broadview's proposal represented a significant departure from any project that the FERC had previously considered under a QF application, which compelled the FERC to reconsider whether a facility's "send out" is determinative of whether the facility complies with the 80 MW PURPA threshold. FERC's Broadview decision essentially overturns the previous "send out" analysis applied in *Occidental Geothermal, Inc.*, 17 FERC ¶ 61,231 (1981). The FERC found that utilizing inverters to limit the output of an otherwise above-80 MW power production facility to 80 MW is inconsistent with the type of facility that can qualify as a small power production facility (i.e., a facility sized 80 MW

[7] Broadview Solar, LLC, 172 FERC ¶ 61,194 (2020) ("Broadview decision").

or less). Broadview could not meet the statutory 80 MW limit by relying on inverters to limit the QF's output; the solar array had the capability to produce 160 MW of DC power. Although the inverters could convert only 80 MW into AC power, the FERC found that "that is a conversion limit, not a limit on the facility's power production capacity."[8]

Because of the timing of the Broadview decision, the stakeholder group was unable to consider those implications in its deliberations. The Utilities respectfully note that they are reviewing the decision and will update this and other filings before the Commission as necessary.

CONCLUSION

Duke Energy appreciates the participation and work done by the members of the stakeholder group and respectfully submits this report for the Commission's consideration. As noted, there appears to have been consensus achieved on several of the topics raised by the Commission in its Sub 158 Order. In addition, for the reasons stated herein, the Companies respectfully request that the Commission approve their recommendation on the appropriate Avoided Cost rates and terms of the PPA applicable to the energy storage element of an existing QF coupled with energy storage.

DENC has authorized the undersigned to sign and file on its behalf.

[8] Broadview decision at Para. 25.

Respectfully submitted, this the 16th day of September, 2020.

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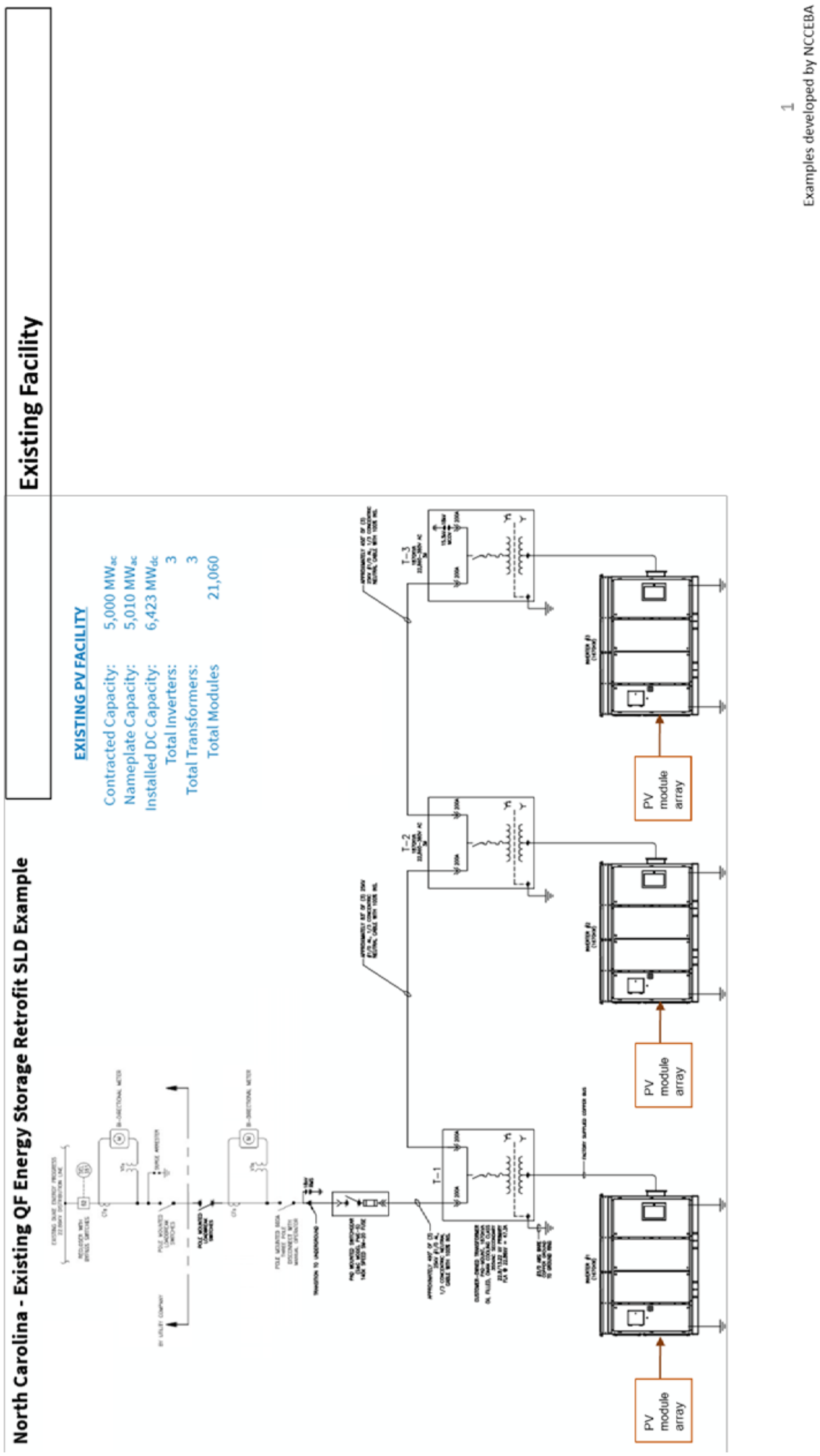
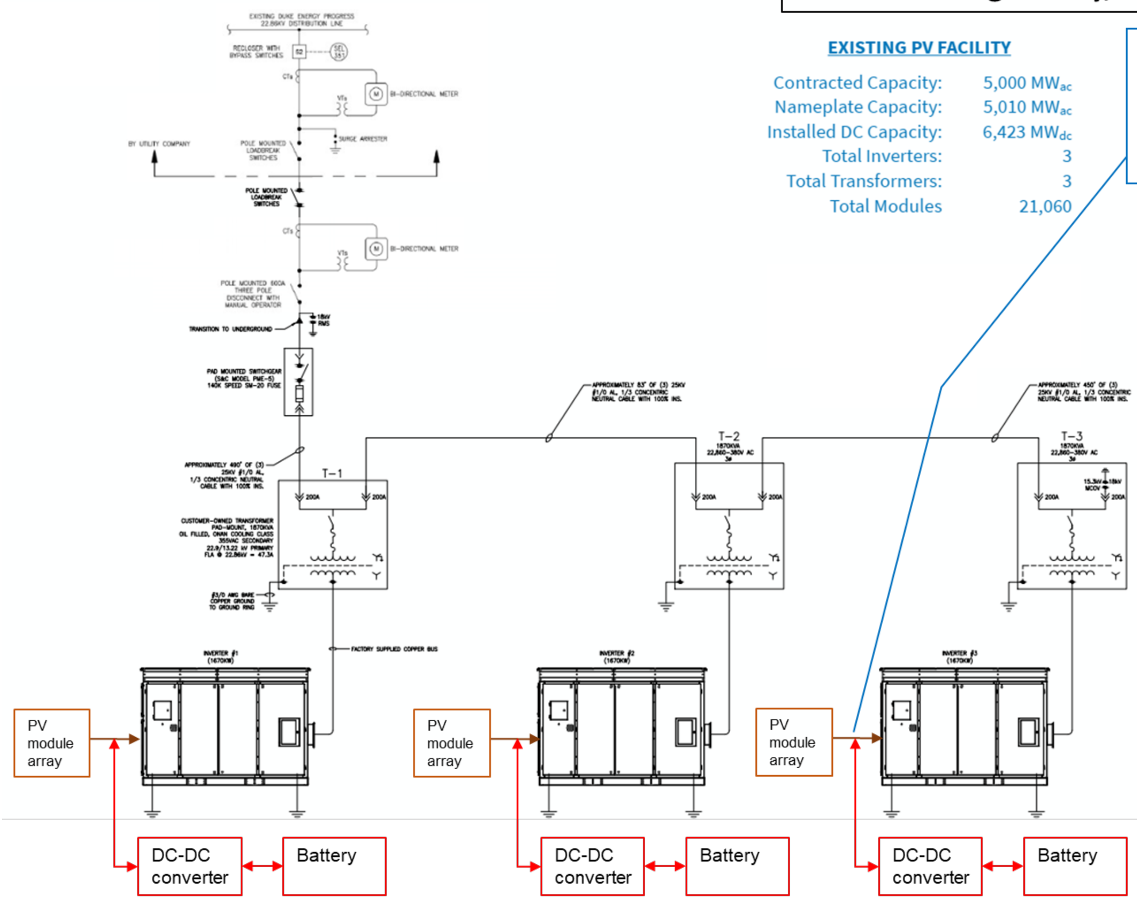
<u>Exhibit A</u>

Single Line Diagrams



North Carolina - Existing QF Energy Storage Retrofit SLD Example

Existing Facility, with retrofitted DC-coupled storage



EXISTING PV FACILITY

Contracted Capacity:	5,000 MW_{ac}
Nameplate Capacity:	5,010 MW_{ac}
Installed DC Capacity:	6,423 MW_{dc}
Total Inverters:	3
Total Transformers:	3
Total Modules	21,060

DC connection point: ease/difficulty of connection will highly vary by site.

One or two DC metering points (transducers + meters) required, per ESS installation. In this drawing, three ESS installations are shown.

Positives

- (+) Mid-day clipped energy capture
- (+) Minimal losses for conversion of PV generation to ESS charging
- (+) No additional equipment needed on AC side in order to manage interconnection
  - Charging from grid not possible
  - No additional kw export: Export controls unchanged from existing (either at each inverter, or via plant controller)

Negatives

- (-) ESS systems tied to each inverter: real limitations on physical placement, number, sizing
- (-) DC connection point complexity
- (-) DC metering integration for billing/accounting

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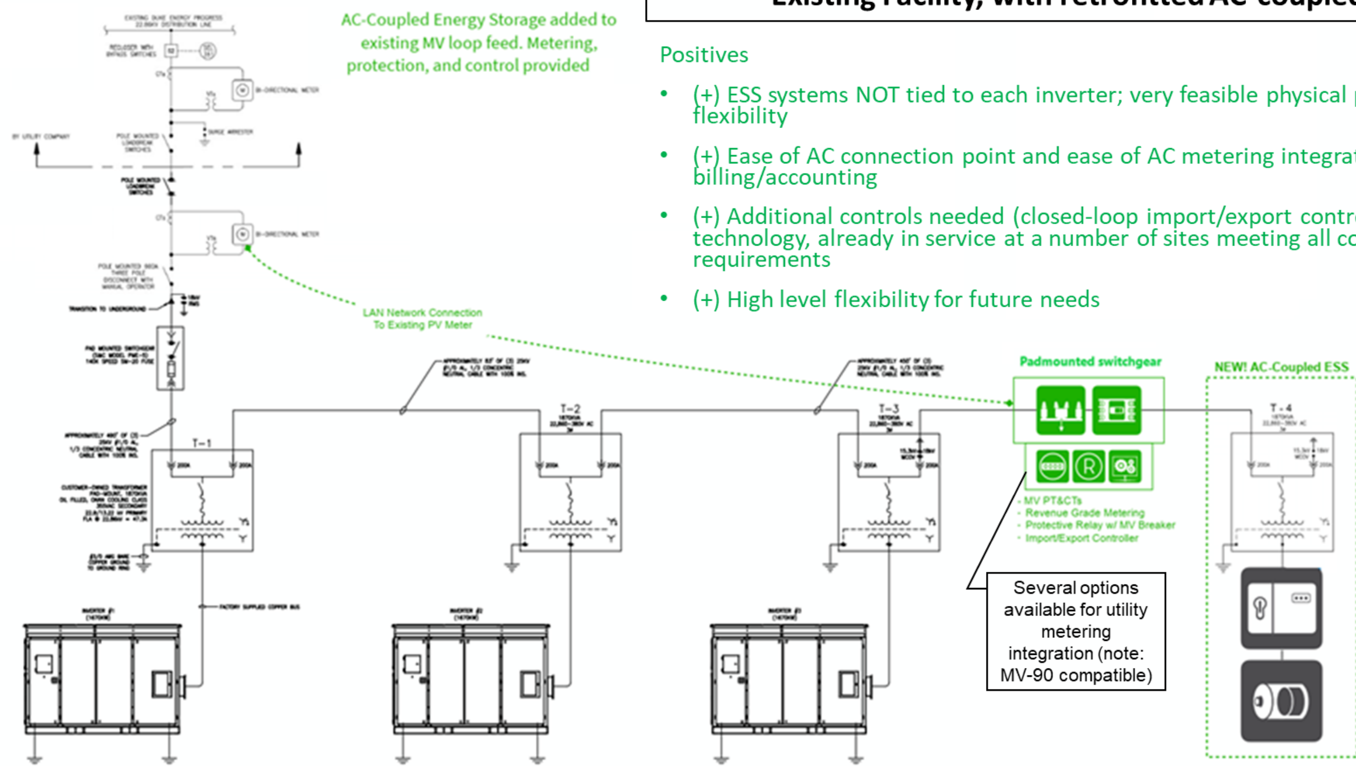
Examples developed by NCCEBA

North Carolina - Existing QF Energy Storage Retrofit SLD Example



- Switched ESS transformer prevents additional inrush current
- Protection/switching interlocks and integration available between utility recloser and ESS switchgear
- Possible impact review for fault duty; for distribution interconnections this would be a small subset of how this would be handled under a LGIP/FERC Surplus Interconnection Service Request.

Existing Facility, with retrofitted AC-coupled storage

Positives

- (+) ESS systems NOT tied to each inverter; very feasible physical placement & sizing flexibility
- (+) Ease of AC connection point and ease of AC metering integration for utility billing/accounting
- (+) Additional controls needed (closed-loop import/export control) is current technology, already in service at a number of sites meeting all compliance requirements
- (+) High level flexibility for future needs

Negatives

- (-) inability to capture mid-day clipped energy
- (-) Additional losses for conversion of PV generation to ESS charging
- (-) May need to add import-export control

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Examples developed by NCCEBA