Lawrence B. Somers
Deputy General Counsel

Mailing Address:
NCRH 20 / P.O. Box 1551
Raleigh, NC 27602

o: 919.546.6722
f: 919.546.2694

bo.somers@duke-energy.com

February 2, 2018

VIA ELECTRONIC FILING

M. Lynn Jarvis
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

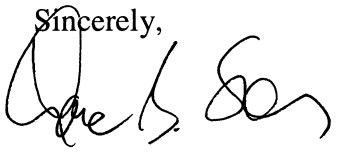
RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Settlement Agreement dated January 30, 2018
Docket No. E-100, Sub 101

Dear Ms. Jarvis:

I write on behalf of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, the Public Staff-North Carolina Utilities Commission, the North Carolina Clean Energy Business Alliance and the other settling parties, and enclose the January 30, 2018 Settlement Agreement by and among Duke Energy Progress, LLC; Duke Energy Carolinas, LLC; the Public Staff-North Carolina Utilities Commission; the North Carolina Clean Energy Business Alliance; Cypress Creek Renewables, LLC; Strata Solar, LLC; Holocene Clean Energy, LLC; Ecoplexus, Inc.; Sunlight Partners, LLC; CI-II Mitchell Holding LLC; Birdseye Renewable Energy; Pine Gate Renewables, LLC; Carolina Solar Energy LLC; National Renewable Energy Corporation; O2 emc, LLC; Red Toad, Inc.; ESA Renewables, LLC; Blue Green Energy, LLC; Calvert Energy, LLC; Headwaters Solar, LLC; Cooperative Solar LLC; Solterra Partners, LLC; ESA Princeton 2 NC; Robert Cox; Andrew Giraldo; Jesse Montgomery; North Carolina Solar Development, LLC; and Current Energy Group, LLC (the "Settlement Agreement") for filing in connection with the referenced matter. As provided for in the Settlement Agreement, it is anticipated that additional parties may become signatories at a later date.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,



Lawrence B. Somers

Enclosures

cc: Parties of Record

Settlement Agreement

This Settlement Agreement ("Agreement") is executed this 30th day of January, 2018 (the "Effective Date"), by and among Duke Energy Progress, LLC ("DEP"); Duke Energy Carolinas, LLC ("DEC") (DEC and DEP together referred to as "Duke Utilities"); the Public Staff-North Carolina Utilities Commission ("Public Staff") the North Carolina Clean Energy Business Alliance ("NCCEBA"); Cypress Creek Renewables, LLC, Strata Solar, LLC, Holocene Clean Energy, LLC, Ecoplexus, Inc., Sunlight Partners, LLC, CI-II Mitchell Holding LLC, Birdseye Renewable Energy, Pine Gate Renewables, LLC, Carolina Solar Energy LLC, National Renewable Energy Corporation, O2 emc, LLC, Red Toad, Inc., ESA Renewables, LLC, Blue Green Energy, LLC, Calvert Energy, LLC, Headwaters Solar, LLC, Cooperative Solar LLC, Solterra Partners, LLC, ESA Princeton 2 NC, Robert Cox, Andrew Giraldo, Jesse Montgomery, North Carolina Solar Development, LLC, Current Energy Group, LLC, and any other developers who become signatories pursuant to Section 8.i (collectively, "Settling Developers"). Terms not defined herein shall have the meaning set forth in the North Carolina Interconnection Procedures ("NC Procedures") adopted by Order of the North Carolina Utilities Commission ("Commission"), issued May 15, 2015, in Docket No. E-100, Sub 101. DEC, DEP, the Public Staff, NCCEBA, and the Settling Developers, are referred to herein individually as "Party" and collectively as the "Parties."

RECITALS

WHEREAS, the Settling Developers are the owners or affiliates of special purpose limited liability companies which in turn are developers in North Carolina of solar photovoltaic small power producer "qualifying facilities" within the meaning of the Public Utilities Regulatory Policies Act, 16 U.S.C. § 824a-3 ("QFs").

WHEREAS, on July 27, 2017, the North Carolina General Assembly enacted Session Law 2017-192 ("S.L. 2017-192" or the "Act") amending the North Carolina Public Utilities Act and affecting certain rights and obligations between the Parties.

WHEREAS, Section 1.(c) of the Act provides, in pertinent part, that certain QFs that otherwise would be eligible for the rate schedules and power purchase agreement terms and conditions approved by the Commission in Docket No. E-100, Sub 140 ("Sub 140 Agreement"), but have failed to commence delivery of power to DEC or DEP on or before September 10, 2018, shall, despite that failure, remain eligible for a Sub 140 Agreement "unless the nameplate capacity of the generation facility when taken together with the nameplate capacity of other generation facilities connected to the same substation transformer exceeds the nameplate capacity of the substation transformer." The QFs that remain eligible for a Sub 140 Agreement under the Act are referred to herein as "Sub 140 QFs."

WHEREAS, on March 18, 2016, DEC and DEP, following negotiations with representatives of the North Carolina QF industry, including many of the Settling Developers, filed with the Commission notice of its agreement and intent to allow QFs otherwise eligible for the rates schedules and power purchase agreement terms and conditions approved by the Commission in Docket No. E-100, Sub 136 ("Sub 136 Agreement") to remain eligible for a Sub 136 Agreement

under specified conditions. The QFs that remain eligible for a Sub 136 Agreement are referred to herein as "Sub 136 QFs."

WHEREAS, DEC has historically applied the transformer manufacturer's base or "Oil-Natural-Air-Natural" ("ONAN") rating as shown on the respective substation transformer[1] as the reasonable and appropriate operating rating up to which it would be acceptable to allow utility-scale power export generating facilities to interconnect to the substation distribution bus and/or retail circuits on the DEC general distribution system ("ONAN Base Nameplate Rating").

WHEREAS, prior to October 2017, DEP had not historically applied a policy limiting utility-scale power export generator interconnections to the ONAN Base Nameplate Rating and had allowed certain facilities to interconnect to the substation distribution bus and/or general distribution circuits at capacities above the ONAN Base Nameplate Rating. DEP has also issued pre-application reports identifying a planning rating value above the ONAN Base Nameplate Rating that historically had been used by DEP for evaluating substation, distribution circuit, and transmission circuit upgrade needs.

WHEREAS, on October 1, 2017, the Duke Utilities began applying new Method of Service Guidelines to delineate the appropriate point of interconnection for additional utility-scale power export distributed generating facilities between interconnections to the Duke Utilities' general distribution systems, direct-to-substation connections, and transmission systems. The Method of Service Guidelines, among other provisions: (i) establish the ONAN Base Nameplate Rating as the appropriate substation transformer nameplate capacity available to interconnect additional utility-scale power export distributed generating facilities on the Duke Utilities' general distribution systems (the "General Distribution Nameplate Capacity Limit"); (ii) limit the capacity of an individual project interconnection on the Duke Utilities' general distribution systems, based on the voltage class of the distribution feeder to which it would interconnect, as identified in Section 2.1.1. of the Guidelines (the "Individual Project on General Distribution Limit"); (iii) limit the aggregate amount of generation permitted on individual distribution feeders based on the Duke Utilities' "distribution planning limit" for the feeder (the "Feeder Limit"); and (iv) limit projects that can interconnect to distribution circuits served by the DEC 44 kV transmission lines to 3 MW_{AC} (the "DEC 44 kV General Distribution Limit"). The Method of Service Guidelines are attached as Attachment 1 to this Agreement.

WHEREAS, the Duke Utilities have informed the Settling Developers of their intention to utilize the ONAN Base Nameplate Rating to determine the substation nameplate rating for purposes of implementing Section 1.(c) of the Act and to utilize the Method of Service Guidelines for studying all proposed interconnections to the Duke Utilities' system that either are currently in or have not begun a System Impact Study under the NC Procedures.

WHEREAS, the Duke Utilities' use of the ONAN Base Nameplate Rating to determine the Substation Nameplate Capacity for purposes of implementing Section 1.(c) of the Act with respect to Sub 140 QFs and use of the Method of Service Guidelines generally would have impacts on certain of the Sub 136 QFs and Sub 140 QFs.

[1] The ONAN Base Nameplate Rating is the nameplate "kVA base" value at which the nameplate percent impedance is expressed, as referred to in IEEE Standard C57.12.00-2006, section 5.12.2, Table 10, NOTE 5.

WHEREAS, certain of the Settling Developers or their QF special purpose affiliates have filed Notices of Dispute against DEC and DEP challenging the use of the ONAN Base Nameplate Rating to determine the Substation Nameplate Capacity for purposes of implementing Section 1.(c) of the Act with respect to Sub 140 QFs and challenging other aspects of the use of the Method of Service Guidelines (the "Disputed Matters").

WHEREAS, NCCEBA, acting on behalf of its members, including the Settling Developers, has indicated their intention to initiate litigation challenging the Method of Service Guidelines.

WHEREAS, in order to resolve the Disputed Matters, the Parties have agreed to the terms of this Agreement.

NOW, THEREFORE, in consideration of the above recitals (which are hereby incorporated by reference) and the promises and mutual covenants set forth herein, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound thereby, the Parties agree each with the other as follows:

1. Determination of Covered Projects.

    a. Subject to the procedure set forth in Section 8.j of this Agreement, the Parties agree that "Covered Projects" for purposes of this Agreement shall mean any Settling Developer's (i) Sub 136 QFs identified as Covered Projects on Attachment 2, and (ii) Sub 140 QFs as determined consistent with the remainder of Section 1 of this Agreement to be eligible for extension of a Sub 140 Agreement pursuant to Section 1.(c) of the Act, which are identified as Covered Projects on Attachment 3.

    b. For purposes of determining the "nameplate of the substation transformer" pursuant to Section 1.(c) of the Act, the Parties agree that (i) DEC shall apply the ONAN Base Nameplate Rating and (ii) DEP shall apply the Oil Natural Air Force name plate rating, which is approximately 167% of the ONAN Base Nameplate Rating, to determine the substation nameplate capacity (the "Substation Nameplate Capacity").

    c. Where a Sub 140 QF's nameplate capacity$_{AC}$, as identified in the applicable Sub 140 QF's Notice of Commitment Form submitted to DEC or DEP ("Requested Nameplate Capacity"), when taken together with the nameplate capacity of other generation facilities already interconnected or with a superior queue position seeking to interconnect to the same substation distribution bus and/or its retail circuits, exceeds the Substation Nameplate Capacity determined in accordance with Section 1.b, above, the Sub 140 QF shall not be eligible for extension of Sub 140 Agreement as provided in Section 1.(c) of the Act. No downsizing from the Requested Nameplate Capacity will be allowed for purposes of determining Sub 140 Agreement eligibility pursuant to Section 1.(c) of the Act.

    d. A QF shall not lose its status as a Covered Project as a result of withdrawing its pending Interconnection Request and filing a new Interconnection Request for a Generating Facility of the same or lesser nameplate capacity, unless, due to its new

queue position, the new QF Interconnection Request causes an exceedance of the applicable Substation Nameplate Capacity.

2. Processing Covered Project Interconnection Requests ("IR") under NC Procedures

   a. For any Covered Project IR, the Duke Utilities shall complete the System Impact Study and Facilities Study and assign the cost of Interconnection Facilities and Upgrades based upon the Duke Utilities' current study criteria as of the Effective Date, including the Method of Service Guidelines, except as otherwise agreed in Section 2.b. of this Agreement (relating to material changes and new interconnection policies, screens, and practices) or as specifically modified by Section 3 of this Agreement (relating to application of the Nameplate Capacity General Distribution Limit in DEP) and Section 4 of this Agreement (relating to application of the Individual Project on General Distribution Limit, the DEC 44kV General Distribution Limit, and the Feeder Limit).

   b. Solely for purposes of this Agreement, and as specifically applied to the Covered Projects, the Duke Utilities further agree: (1) not to materially change the Method of Service Guidelines or any other currently effective interconnection policies and practices applied to studying the Covered Projects, including, but not limited to, the Duke Utilities' current practice of offering multiple mitigation options at various MW_{AC} sizes and costs, and (2) not to introduce any new interconnection policies, screens, or practices applied to studying such Covered Projects, unless required by a change in applicable law or ordered by the Commission. In the event of a dispute over the interconnection policies and practices applied to studying the Covered Project(s), a Settling Developer may invoke the dispute resolution processes set forth in NC Procedures Section 6.2.

3. Application of General Distribution Nameplate Capacity Limit to Covered Projects in DEP Exceeding ONAN Base Nameplate Rating

   a. Exempt DEP Covered Project IRs. Any DEP Covered Project IR identified on Attachment 2 or Attachment 3 as not exceeding 133% of the ONAN Base Nameplate Rating of the associated substation transformer [*e.g.*, 20 MVA on 15/20/25 MVA nameplate-rated DEP transformer] (the "Mid Rating") shall be deemed grandfathered and exempted from the General Distribution Nameplate Capacity Limit ("Exempt DEP Covered Project IRs").

   b. DEP Covered Project IRs Requiring Substation Work. Any DEP Covered Project IR whose Requested Nameplate Capacity, when taken together with the nameplate capacity of other distribution-connected utility-scale power export distributed generation facilities already interconnected or with a superior queue position seeking to interconnect to the same substation distribution bus and/or its retail circuits causes the aggregate generating facility capacity to exceed the Mid Rating shall be studied one of three ways: (1) a "Method D" interconnection if its size meets Method "D" requirements, (2) as a "Method S" interconnection if its size meets Method "S" requirements, or (3) as a Method "S" interconnection (when its

full size would normally classify it as a Method "D" interconnection under the Individual Project on General Distribution Limit) if doing so would present technical solutions of lesser total upgrade costs to the DEP Covered Project IR than studying as a "Method D" interconnection, based upon Good Utility Practice ("Non-Exempt DEP Covered Project IRs").

i. As part of DEP's System Impact Study evaluation of Non-Exempt DEP Covered Project IRs under this subsection, DEP will evaluate the need for and accelerate or develop plans to cause upgrades or additions to substation equipment, as needed, to ensure that the generating facility can be safely and reliably interconnected consistent with Good Utility Practice. DEP will specifically evaluate substation equipment upgrades required so that the aggregate of connected and operating capacity of existing generation facilities and the Non-Exempt DEP Covered Project IRs does not exceed the ONAN Base Nameplate Rating of the substation transformer or, if determined to be feasible and consistent with Good Utility Practice, develop alternative technical solutions that can be accommodated "inside the fence" at the substation that do not require an increase in the substation transformer capacity, to ensure the generating facility can be safely and reliably interconnected ("Substation Work"), notwithstanding such exceedance. Where expansion of substation capacity is not feasible due to site specific limitations such as, but not limited to, real estate constraints, configuration of local distribution circuits, specialized substation equipment limitations, short-term and long-term area planning needs, etc., DEP will evaluate alternative Upgrade technical solutions for Non-Exempt DEP Covered Project IRs in as similar as possible a fashion as it would for capacity increases pursued for load growth planning.

ii. The ballpark cost and timeframe to complete Substation Work shall be specifically identified in the System Impact Study report delivered to the Interconnection Customer. The Non-Exempt DEP Covered Project IR Customer shall then have twenty (20) calendar days from DEP's issuance of the System Impact Study report to request a meeting to discuss the required Substation Work. The Non-Exempt DEP Covered Project IR Customer may identify proposed alternative options to the Substation Work, and DEP agrees to consider whether any such Customer proposals meets Good Utility Practice and achieves acceptable system reliability. To the extent the identified changes are acceptable to DEP, as consistent with Good Utility Practice, it shall restudy the Non-Exempt DEP Covered Project IR based upon the modified Substation Work. If DEP does not accept a Non-Exempt DEP Covered Project IR Customer-supported alternative Substation Work proposal, DEP shall notify the Customer in writing and the Interconnection Customer shall be required to submit a Facilities Study Agreement and proceed with interconnection study under NC Procedures Section 4.4. In the event of a dispute over the acceptability of a proposed alternative, the Non-Exempt DEP Covered Project IR

Customer may invoke the dispute resolution processes set forth in NC Procedures Section 6.2.

iii. The Parties recognize and agree that a Non-Exempt DEP Covered Project IR Customer proceeding under this subsection shall be responsible for any Substation Work identified through System Impact Study as part of the Upgrades caused by the interconnection, unless DEP determines and the Public Staff agrees that a portion or all of the cost of Substation Work provides system benefits that should be fully assigned or reasonably allocated to retail load customers. If the Public Staff agrees to allocate specific substation Upgrade costs based upon a "system benefits" determination, DEP will assign such Upgrade costs to the Non-Exempt DEP Covered Project IR Customer based upon the allocation agreed to between the Public Staff and DEP. In the event that it disputes the "system benefits" determination or allocation, the Non-Exempt DEP IR Customer may invoke the dispute resolution processes set forth in NC Procedures Section 6.2.

iv. The Parties further agree that DEP shall only be required to evaluate Substation Work at the 24 substations identified in Attachment 4 to this Agreement associated with Non-Exempt DEP Covered Project IRs.

v. The Parties acknowledge and agree that Non-Exempt DEP Covered Project IRs subject to this subsection may cause increased backfeed of energy from the distribution circuit through the existing or upgraded substation transformer onto the transmission system, and that DEP must therefore fully analyze potential transmission system impacts of such IRs as part of the System Impact Study in accordance with the NC Procedures. DEP agrees to make its methodology for the study of such potential transmission system impacts available to NCCEBA within thirty (30) calendar days of the Effective Date and to provide NCCEBA an opportunity to comment on such methodology. The Parties acknowledge and agree that any required Upgrades that are not included in the limited scope of Substation Work, including any Upgrades required on the transmission system, will be fully assigned to the Non-Exempt DEP Covered Project IR Interconnection Customer to the extent allowed by applicable state or federal law, orders, or interconnection procedures.

vi. The Parties acknowledge and agree that the engineering, design, procurement, and construction required for DEP to complete Substation Work on 24 substations may take multiple years to complete, and at DEP's current estimate may take three (3) to six (6) years to complete. DEP will complete such Substation Work in Queue Position priority, unless other safety or reliability factors justify earlier action on an affected substation. The Parties recognize and agree that the complexity of individual Substation Work and the need to otherwise maintain Good Utility Practice will also need to be considered along with availability of engineering and

construction resources to complete the necessary work. The Settling Developers also acknowledge and accept that the foregoing factors may impact and delay planned commercial operation dates for Non-Exempt DEP Covered Project IR generating facilities where Substation Work involving substation capacity upgrades is required. The Appendix 4 milestones set forth in the Interconnection Agreement will identify the planned timeframe for completion of Substation Work and the proposed in-service date for approved parallel operation of the generating facility.

vii. DEP shall evaluate in System Impact Study and provide to all Non-Exempt DEP Covered Project IRs a mitigation option to reduce its capacity to comply with the Mid Rating and thereby become an Exempt DEP Covered Project IR covered by subsection 3.a. of this Agreement. Implementation by the Non-Exempt DEP Covered Project IR of such mitigation option presented by DEP in the System Impact Study report, regardless of the size of the capacity reduction, shall not be deemed to constitute a material modification within the meaning of the NC Procedures.

c. DEP will study DEP Covered Project IRs sequentially in Queue Position priority order under the NC Procedures, which may include the need for System Impact restudy for Exempt DEP Covered Project IRs below the Mid-Rating and may require additional evaluation of Substation Work for any Non-Exempt DEP Covered Project IRs that exceed the Mid-Rating. The Parties acknowledge and agree that any Non-Exempt DEP Covered Project IR triggering Substation Work under this subsection may require significant additional study, design, and engineering during System Impact Study and Facilities Study to support the Substation Work.

4. Deviation from Other Method of Service Guideline Requirements for Covered Projects

a. The Duke Utilities shall apply the Individual Project on General Distribution Limit and the DEC 44 kV General Distribution Limit to Covered Projects, except that any Covered Project whose nameplate capacity requested indicates the requirements for a Method "S" interconnection as detailed in Table 1 in section 2.1.1 of the Method of Service Guidelines shall be provided two options as part of its System Impact Study: full requested size (for a Method "S" interconnection) and a downsized mitigation option to meet the requirements for a Method "D" interconnection. Implementation by the Covered Project of such mitigation option, regardless of the size of the capacity reduction, shall not be deemed to constitute a material modification within the meaning of the NC Procedures.

b. The Duke Utilities shall not apply the Feeder Limit to Covered Projects. Instead, any Covered Project being studied as a Method "D" interconnection under the Method of Service Guidelines, whose Requested Capacity causes the aggregate capacity of distribution-connected utility-scale power export distributed generating facilities on a specific distribution circuit to exceed the Feeder Limit, is instead

subject to an aggregate DER circuit limit of 20 MWac on 25 kV class circuits or 10 MWac on 15 kV class circuits.

5. Support for Substation Work Cost Recovery

   a. The Settling Developers and NCCEBA shall not oppose and, if challenged, shall provide supporting comments for any request by DEP to the Commission in any future ratemaking proceeding to recover any costs incurred for Substation Work that is assigned or allocated to load customers and not recovered from the Non-Exempt DEP Covered Project IR Customer as an Upgrade, as discussed in Section 3.b. above.

   b. The Public Staff agrees that it will not oppose DEP's ability to recover from customers in any future ratemaking proceeding specific costs incurred by DEP to complete any Substation Work found to provide system benefits, which the Public Staff has agreed to or otherwise has not opposed being allocated to retail load customers and not to the Non-Exempt DEP Covered Project IR customers as an Upgrade; however, the Public Staff shall retain the right to challenge specific amounts of such costs should it determine that such specific amounts were excessive and therefore not reasonably and prudently incurred.

   c. The Parties recognize and agree that the Duke Utilities' agreement to deviate from the Method of Service Guidelines for the Covered Projects, as addressed herein, and to potentially allocate the cost of Substation Work to retail load customers, as addressed in Section 3.b. of this Agreement, is exclusively related to implementing Section 1.(c) of the Act and settling the Disputed Matters. Nothing contained herein shall limit, or be construed to limit (i) the right of the Duke Utilities in all other cases not addressed herein to fully adhere to Good Utility Practice, as determined by DEC and DEP, respectively, to implement the Method of Service Guidelines, or to fully assign the cost of interconnection facilities and Upgrades to generating facilities requesting interconnection under the NC Procedures, or (ii) the Settling Developers and/or NCCEBA's right to (x) challenge any such actions on grounds other than a claim of precedent established by this Agreement, or (y) challenge other actions by the Duke Utilities unrelated to the Disputed Matters. NCCEBA and the Settling Developers further agree that the Duke Utilities' commitments to deviate from the Method of Service Guidelines and to evaluate the need for and to complete the Substation Work provided for herein shall not be cited as precedential by any Parties to this Agreement to support any argument for deviating from the Duke Utilities' application of Good Utility Practice in the future or that Upgrade costs should not be fully assigned to and recovered from any Interconnection Customer requesting to interconnect under the NC Procedures.

6. Agreement not to Challenge Method of Service Guidelines

   a. Provided that the Duke Utilities' fully comply with the terms of this Agreement, and except as specifically provided herein, NCCEBA and the Settling Developers agree not to challenge or dispute the Duke Utilities' use of current Method of

Service Guidelines for purposes of evaluating the interconnection of utility-scale power export distributed generating facilities requesting to interconnect to the DEP and DEC distribution systems other than the Covered Projects as provided herein. Except as specifically provided for in Sections 3 and 4 of this Agreement related to the Covered Projects, DEC and DEP shall apply the Method of Service Guidelines, and all other currently-effective, publicly available interconnection policies and practices to delineate the appropriate point of interconnection on the utility system and to model the costs and impacts of proposed Covered Project interconnections through the System Impact Study under the NC Procedures. Notwithstanding the foregoing, the Parties acknowledge and agree that there have been and may continue to be disputes between the Settling Developers and the Duke Utilities concerning Section 3 of the Method of Service Guidelines and that this Agreement does not resolve, or preclude the pursuit by the Settling Developers, of such disputes.

b. Should any party challenge this Agreement or the relief provided herein to the Settling Developers, the Duke Utilities and the Settling Developers and/or NCCEBA on behalf of the Settling Developers will intervene and actively oppose such challenge.

7. Withdrawal of Pending Notices of Dispute Related to Method of Service Guidelines

a. Within ten (10) calendar days of executing this Agreement, the Settling Developers that have submitted Notices of Dispute under the NC Procedures agree to provide notice in writing to the Duke Utilities and the Public Staff withdrawing such disputes to the extent they relate to matters resolved by this Agreement.

8. Miscellaneous

a. This Agreement constitutes a negotiated settlement and is the result of a compromise by the Parties. The Agreement does not constitute and shall not be construed to constitute an admission of liability or wrong doing, nor shall it be construed to constitute an endorsement by a party of any legal or policy position advocated by another party. This Agreement shall not be cited as precedent, nor shall it be deemed to bind the Duke Utilities, the Public Staff, NCCEBA, or any Settling Developers (except as otherwise expressly provided for herein), in any future proceeding, including proceedings before the Commission.

b. The Parties hereto agree to execute and deliver such other and further agreements or documents as may be necessary to effectuate fully the agreements and intentions of the Parties as expressed herein.

c. This Agreement may be executed independently in any number of counterparts, each of which when executed and delivered, shall constitute an agreement which shall be binding upon the parties notwithstanding that the signatures of all parties and/or their designated representatives do not appear on the same page. Facsimile, PDF, and electronic signatures shall have the same effect as original signatures.

d. The Parties and their signatories warrant that each has the power and authority to execute this Agreement; and the parties voluntarily execute this Agreement based on their own independent investigations.

e. This Agreement and all documents referenced herein shall be governed and interpreted under the laws of the State of North Carolina and is subject to the jurisdiction of the Commission under the NC Procedures.

f. The provisions of this Agreement shall be interpreted in a manner consistent with each other to carry out the purposes and intentions of the parties. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by the Commission or any court of competent jurisdiction, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

g. This Agreement contains the ENTIRE Agreement between the parties hereto, and the terms and conditions thereof are contractual in nature and not mere recitals. Each Party acknowledges and agrees that it has read fully and understood this Agreement; that they understand that such document involves substantial legal rights; that they have had the opportunity to review and discuss same with their own counsel; and that each Party enters this Agreement of its own free act, without any measure of duress.

h. Each Settling Developer is entering into this Agreement on behalf of itself and its affiliates, who shall be deemed to be Parties to this Agreement with the same rights and obligations under this Agreement as their signatory affiliate.

i. On or before the thirtieth (30) calendar day after the Effective Date, a QF developer that owns a project identified on Attachment 2 or Attachment 3 to this Agreement may become a Party to the Agreement as a Settling Developer and thereby become subject to all of the rights and obligations of a Settling Developer under this Agreement through delivery of an executed copy of this Agreement to all existing Parties. The signature page tendered by such QF developer must specifically identify the project(s) listed on Attachment 2 or Attachment 3 that will become a Covered Project. Such developer shall become a Party to this Agreement unless, within fifteen (15) days of receipt of the executed copy of this Agreement, any existing Party objects to the developer's eligibility to become a Party to this Agreement. In the case of such an objection, the developer shall not become a party to this Agreement unless and until such objection has been resolved to the satisfaction of all Parties.

IN WITNESS WHEREOF, the parties have signed, executed, and agree to the foregoing Settlement Agreement.

Duke Energy Progress, LLC /
Duke Energy Carolinas, LLC

By: _____

David B. Fountain
President, North Carolina

Public Staff-North Carolina
Utilities Commission

By: _____

Christopher J. Ayers
Executive Director

North Carolina Clean Energy Business
Alliance

By: _____

Chris Carmody
Executive Director

[Additional Signatories on Subsequent Pages]

Cypress Creek Renewables, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____

Matthew McGovern
Chief Executive Officer

Date: 1 / 3 0 / 2018

Interconnection Customer	**Interconnecting Utility**	**Queue Number**
Anjuna Solar, LLC	DEP	NC2016-02775
Banner Solar, LLC	DEP	NC2016-00031
Bayles Farms Solar, LLC	DEP	CHKLIST-9054
Beckwith Solar, LLC	DEP	NC2016-02778
Beebe Solar, LLC	DEP	NC2016-02949
Boylston Solar, LLC	DEP	NC2016-02789
Brick City Solar, LLC	DEP	NC2016-02803
Broadway Road Solar, LLC	DEP	CHKLIST-10222
Buttercup Solar, LLC	DEP	NC2016-02792
Caswell Solar, LLC	DEP	CHKLIST-8126
Centerville Church Solar LLC	DEP	CHKLIST-9505
Chickenfoot Solar, LLC	DEP	CHKLIST-8480
Clarksbury Solar, LLC	DEC	NC2016-02851
Climax Solar Project, LLC	DEC	CHKLIST-10523
Country Club Solar, LLC	DEP	NC2016-02838
County Home Solar, LLC	DEP	CHKLIST-8627
Daniel Solar, LLC	DEC	CHKLIST-9157
Eastway Solar, LLC	DEP	NC2016-02810
Ellisboro Solar, LLC	DEC	NC2016-02817
Eros Solar, LLC	DEP	NC2016-02812
Golden Road Solar, LLC	DEP	NC2016-02771
Henry Gibson Solar, LLC	DEP	CHKLIST-9196

Continued on next page

Cypress Creek Renewables, LLC
Continued from previous page

Interconnection Customer	Interconnecting Utility	Queue Number
Jester Solar, LLC	DEP	NC2015-00064
Lane Solar Farm II, LLC	DEP	NC2015-00040
McCullen Solar, LLC	DEP	CHKLIST-7991
Moyer Solar, LLC	DEC	NC2015-00052
Mule Farm Solar, LLC	DEP	CHKLIST-9971
Old Road Solar, LLC	DEC	NC2015-00053
Organ Church Solar, LLC	DEC	CHKLIST-9218
Osceola Solar, LLC	DEC	NC2016-02821
Peach Solar, LLC	DEP	CHKLIST-8081
Pelican Solar, LLC	DEC	NC2017-03041
Pilot Mountain Solar, LLC	DEC	NC2016-02813
Ransom Solar, LLC	DEP	NC2016-02804
Red Cedar Solar, LLC	DEC	CHKLIST-9155
Red Toad 4451 Buffalo Road, LLC	DEP	CHKLIST-8408
Reunion Solar, LLC	DEP	CHKLIST-8677
Saw Solar, LLC	DEC	NC2016-02904
SAXAPAHAW SOLAR, LLC	DEC	NC2016-02829
Siler Solar, LLC	DEP	CHKLIST-8106
Snake Solar, LLC	DEP	CHKLIST-8626
South Creek Solar, LLC	DEP	CHKLIST-9198
Spring Hope Solar 2, LLC	DEP	CHKLIST-8098
Tamarama Solar, LLC	DEC	NC2016-02776
Trestles Solar, LLC	DEC	NC2017-03042
Trinity Solar, LLC	DEC	CHKLIST-9734
Trojan Solar, LLC	DEP	NC2016-02819
Turner Smith Solar, LLC	DEC	CHKLIST-9083
Ventura Solar, LLC	DEC	NC2016-02797
Whiskey Solar, LLC	DEP	CHKLIST-9211
Willard Solar, LLC	DEP	NC2016-00005
Zuma Solar, LLC	DEC	NC2016-02777

Strata Solar, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____
Markus Wilhelm
Manager

Date: 1/30/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Canon Farm, LLC	*DEP*	CHKLIST-9727
Tinker Farm, LLC	*DEP*	CHKLIST-8121
Evers Farm, LLC	*DEP*	CHKLIST-8122
Swift Creek Farm, LLC	*DEP*	CHKLIST-9479
Starr Farm, LLC	*DEP*	CHKLIST-9922
Belafonte Farm, LLC	*DEP*	CHKLIST-9055
Tubbs Farm , LLC	*DEP*	CHKLIST-8237
Trent River Farm, LLC	*DEP*	NC2016-00030
Gilead Farm, , LLC	*DEP*	CHKLIST-11331 / NC2015-00033
Riverboat Farm, LLC	*DEP*	NC2016-00041
Gladstone Farm, LLC	*DEP*	NC2016-02780
Wedge Solar, LLC	*DEP*	NC2016-02794
Ramp Solar, LLC	*DEP*	NC2016-02805
Marchpast Solar, LLC	*DEP*	NC2016-02793
Shieldwall Solar, LLC	*DEP*	NC2016-02788

Wentworth Farm, LLC	DEC	NC2016-02808
Rea Magnet Farm, LLC	*DEP*	NC2016-02811
Selwyn Farm, LLC	*DEP*	NC2016-02809
Cookstown Solar Farm, LLC	*DEP*	NC2016-02845
Wadesboro Farm 4, LLC	*DEP*	NC2016-02824
Necal Farm, LLC	*DEC*	NC2016-02840
Monday Farm, LLC	*DEP*	NC2016-02879
Flatwood Farm, LLC	*DEP*	NC2016-02852
Kendall Farm, LLC	*DEP*	NC2016-02866
Mastiff Solar, LLC	*DEP*	NC2016-02825
Overhill Solar, LLC	*DEP*	NC2016-02855
Aberdeen Farm, LLC	*DEP*	NC2016-02849
River Forks Farm, LLC	*DEP*	NC2016-02856
Verona Solar, LLC	*DEP*	NC2016-02853
Peake Road Farm, LLC	*DEP*	NC2016-02880
Buchanan Farm, LLC	*DEP*	NC2016-02898
Changeup Solar, LLC	*DEP*	NC2016-02931
Faraday Farm, LLC	*DEP*	NC2016-02938
Hoover Farm, LLC	*DEP*	NC2016-02869
Polk Farm, LLC	*DEP*	NC2016-02893
Quincy Farm, LLC	*DEC*	NC2016-02887
Seagrove Farm, LLC	*DEP*	CHKLIST-8105
Taft Farm, LLC	*DEC*	NC2016-02916
Tarpey Farm, LLC	*DEC*	NC2016-02924
Achilles Farm, LLC	*DEP*	CHKLIST 8135
Truman Farm, LLC	*DEP*	NC2016-02872
Eisenhower Farm, LLC	*DEP*	NC2016-02873
Badger Farm, LLC	*DEP*	NC2016-02871

Bladenboro Farm 2, LLC	*DEP*	CHKLIST-8893
Westwood Farm, LLC	*DEP*	NC2015-00014
Highway 16 Farm , LLC	*DEC*	NC2015-00048
Lexington 64 Farm, LLC	*DEC*	NC2016-02839
Summit Solar, LLC	*DEP*	NC2018-03103
Edison Farm, LLC	*DEC*	NC2017-03065
Ilium Solar, LLC	*DEP*	NC2017-03083
McGrigor Farm Solar, LLC	*DEP*	NC2016-00021
Sellers Farm Solar, LLC	*DEP*	CHKLIST 10361
Cabaniss Farm, LLC	*DEP*	NC2015-00044
Storys Creek Farm Solar, LLC	*DEP*	NC2016-02850
Tides Lane Farm Solar, LLC	*DEP*	NC2015-00028

Holocene Finance, LLC (d/b/a Holocene Clean Energy), on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____
Stanford Allison
CFO

Date: 2.1.18

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
ESA Four Oaks 2	DEP	CHKLIST-10362
HCE Columbus I	DEP	NC2015-00031
HCE Columbus II	DEP	NC2015-00043
HCE Moore I	DEP	NC2015-00047
Page Solar	DEC	NC2016-00042

Sunlight Partners, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____

Robert Desrosiers
EVP of its Manager
Cate Street Capital, Inc.

Date: February 2, 2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
TATE SOLAR, LLC	DEP	CHKLIST-8720
EAGLE SOLAR, LLC	DEP	CHKLIST-8767
ROBIN SOLAR, LLC	DEP	CHKLIST-8802
BROOKE SOLAR, LLC	DEP	CHKLIST-8658
IZIA SOLAR, LLC	DEP	CHKLIST-8659
ROMAN SOLAR, LLC	DEP	CHKLIST-8719
HIGGINS SOALR, LLC	DEP	CHKLIST-8803
IGA SOLAR, LLC	DEP	CHKLIST-8821
ALEXIS SOLAR, LLC	DEP	CHKLIST-8657
SHELTER SOLAR, LLC	DEP	CHKLIST-8651
JUNE SOLAR, LLC	DEP	CHKLIST-8717
WILFORK SOLAR, LLC	DEP	CHKLIST-8794
ICARUS SOLAR, LLC	DEP	CHKLIST-8820
LONGLEAF SOLAR, LLC	DEP	CHKLIST-8827
BLUE BIRD SOLAR, LLC	DEP	CHKLIST-8906
CASH SOLAR, LLC	DEP	CHKLIST-8908
KATHLEEN SOLAR, LLC	DEP	CHKLIST-8910
GROVE SOLAR, LLC	DEP	CHKLIST-9028

CI-II Mitchell Holding LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____

Jonathan Burke
Authorized Agent of CI-II Mitchell Holding LLC

Date: February 2, 2018

Interconnection Customer	Interconnecting Utility	Queue Number
1001 Ebenezer Church Solar, LLC	DEC	NC2016-02818
1003 Whitney Solar, LLC	DEC	NC2016-02828
1008 Matthews Solar, LLC	DEC	NC2016-02826
1025 Traveller Solar, LLC	DEP	NC2016-02833
1031 Winthrow Creek Solar, LLC	DEC	NC2016-02861
1034 Catherine Lake Solar, LLC	DEP	NC2016-02846
1035 Lee Landing Solar, LLC	DEP	NC2016-02822
1045 Tomlin Mill Solar, LLC	DEC	NC2016-02847
1047 Little Mountain Solar, LLC	DEC	NC2016-02862
1051 Lucky Solar, LLC	DEC	NC2016-02857
Delta Solar, LLC	DEC	NC2016-02901
Burgaw Solar, LLC	DEP	NC2016-02910
1073 Onslow Solar, LLC	DEP	NC2016-02913
Woodington Solar, LLC	DEP	NC2016-02885
Pecan Grove Solar, LLC	DEP	NC2016-02926
Sweet Tea Solar, LLC	DEP	NC2016-02884
Ray Wilson Solar, LLC	DEC	NC2016-02894
Carolina Lily Solar, LLC	DEP	NC2016-02921
Apple Pie Solar, LLC	DEP	NC2016-02891
Swansboro Solar, LLC	DEP	NC2016-02903
Airport Solar, LLC	DEP	NC2016-02928
Suncaster, LLC	DEP	NC2016-02883
Solar Lee, LLC	DEP	NC2016-02896
Ennis Solar, LLC	DEP	NC2016-02914
Brewington Solar, LLC	DEP	NC2016-02917
Sykes Solar, LLC	DEP	NC2016-02890
Union Chapel Solar, LLC	DEP	NC2016-02908
Acme Solar, LLC	DEP	NC2016-02888
Williams Solar, LLC	DEP	NC2016-02927
Pitt County Solar, LLC	DEP	NC2016-02892
Gray Mill Solar, LLC	DEP	NC2016-02925
Glenfield Solar, LLC	DEP	NC2016-02923
Elk Solar, LLC	DEP	NC2016-00010
Gray Fox Solar, LLC	DEP	NC2016-00028

Birdseye Renewable Energy, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: 

Brian Bednar
President

Date: 2/2/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
McLean Homestead, LLC	Duke Energy Progress	CHKLIST-10493
Tamworth Holdings, LLC	Duke Energy Progress	NC2016-02820
Tanager Holdings, LLC	Duke Energy Progress	NC2016-02912
Warbler Holdings, LLC	Duke Energy Carolinas	NC2016-02823

Pine Gate Renewables, LLC, *on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____
Zoë Gamble Hanes
Manager

Date: February 1, 2018

Interconnection Customer	Interconnecting Utility	Queue Number
Arthur Solar 2, LLC	DEP	CHKLIST-10544
Crawford Solar, LLC	DEP	CHKLIST-10585
Spring Hope Solar 3, LLC	DEP	CHKLIST-8097
Warrenton Solar 1, LLC	DEP	CHKLIST-8118
Hubble Solar, LLC	DEP	NC2015-00009
Clovelly Solar, LLC	DEP	NC2016-00023
Sawtell Solar, LLC	DEP	NC2016-00024
Cathcart Solar, LLC	DEP	NC2016-02796
Cubera Solar, LLC	DEP	NC2016-02955
Coogee Solar, LLC	DEP	NC2016-02960
Mila Solar, LLC	DEP	NC2016-02787
Armada Solar, LLC	DEP	NC2016-02798
Cedar Grove Solar, LLC	DEP	CHKLIST-8586
Thigpen Farms Solar, LLC	DEP	CHKLIST-8624
Olympus Solar, LLC	DEP	NC2016-02801

Carolina Solar Energy II, LLC
~~[DEVELOPER]~~, *on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: Gary Dudzik, COO
[NAME]
[TITLE]

Date: 2-1-18

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Sellers Farm Solar, LLC	DEP	CHKLIST-10361
Tides Lane Farm Solar ,LLC	DEP	NC2015-00028-1
McGrigor Farm Solar, LLC	DEP	NC2016-00021
Cabaniss Farm, LLC	DEP	NC2015-00044
Storys Creek Farm Solar, LLC	DEP	NC2016-02850
Chester Lane Solar, LLC	DEP	NC2016-02815

National Renewable Energy Corporation, Its Manager, *in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: Jesse Montgomery

Name: Jesse Montgomery

Title: President, Development

Date: 1/31/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Violet Solar, LLC	DEC	CHKLIST-9703

O2 emc, LLC, a North Carolina limited liability company, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____
Olee Joel Olsen, Jr., Manager

Date: 1/30/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Gamble Solar, LLC	DEC	NC2016-02865
Bear Poplar Solar, LLC	DEC	NC2016-02783
Salisbury Solar, LLC	DEC	NC2016-00016

Red Toad, Inc, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____
Reynaldo Rodriguez
Chief Executive Officer

Date: 2/1/2018

Interconnection Customer:	Interconnecting Utility:	Queue Number:
Red Toad 5840 Buffalo Road, LLC	DEP	CHKLIST-8402
Red Toad 315 Vinson Road, LLC	DEP	CHKLIST-9062
Red Toad Powatan Phase 2, LLC	DEP	CHKLIST-9070
Red Toad Phase 2 Buffalo Road, LLC	DEP	CHKLIST-9073
Red Toad 275 Vinson Road, LLC	DEP	CHKLIST-9261

ESA Renewables, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: Lindsay Latre

Lindsay Latre
Chief Operating Officer

Date: February 1, 2018

Interconnection Customer:	Interconnecting Utility:	Queue Number:
Wendell Solar Farm, LLC	DEP	NC2016-02841
ESA Buies Creek, LLC	DEP	NC2016-02950
Warren Solar Farm, LLC	DEP	NC2016-02911
Parker Solar Farm, LLC	DEC	NC2016-02957
Airlie Solar Farm, LLC	DEC	NC2015-00056
Charity Solar Farm, LLC	DEP	NC2015-00035
ESA Goldsboro NC Phase 2, LLC	DEP	9156
ESA Goldsboro NC, LLC	DEP	9024
ESA Hamlet NC, LLC	DEP	8611
ESA Kinston NC LLC	DEP	9139
Oakwood Solar Farm, LLC	DEC	NC2015-00042
Wyse Fork Solar Farm, LLC	DEP	NC2015-00032
Benson Solar Farm, LLC	DEP	NC2015-00055
County Farm Solar Farm LLC	DEC	8881
Horner Siding Solar Farm LLC	DEP	9046
ESA Four Oaks 2 LLC	DEP	10362
ESA Boston Solar, LLC	DEP	NC2016-02868

Hood Solar Farm, LLC	DEP	NC2016-02831
Millers Chapel Solar Farm, LLC	DEP	NC2016-00047
Thanksgiving Fire Solar Farm, LLC	DEP	NC2016-02860
ESA Albemarle NC, LLC	DEP	NC2016-02948
Southwick Solar Farm LLC	DEP	NC2016-02834
Stagecoach Solar Farm LLC	DEP	NC2016-02795
Woodgriff Solar Farm, LLC	DEP	NC2016-02945
ESA Erwin NC, LLC	DEP	8883
Norris Solar Farm, LLC	DEC	NC2016-02951
HCE Moore I, LLC	DEP	NC2015-00047
Page Solar Farm, LLC	DEP	NC2016-00042

Blue Green Energy, LLC on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: Heath McLaughlin

Heath McLaughlin
Member

Date: 01/31/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Thanksgiving Fire Solar Farm, LLC	DEP	NC2016-02860

Calvert Energy LLC, *on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____

Brian Quinlan
President/CEO

Date: January 30, 2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Pine Valley Solar Farm, LLC	DEP	CHKLIST-10607

Headwaters Solar, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: Veronika Gunter 2018.02.02 11:21:53 -05'00'

Veronika Gunter
Member, Headwaters Solar, LLC

Date: 2-2-2018

Interconnection Customer:	Interconnecting Utility:	Queue Number:
Scotch Bonnet Solar, LLC	DEP	NC2016-02929
Cumberland Solar, LLC	DEP	NC2016-02902
Morgan Sellers Solar, LLC	DEP	NC2016-02935
Yadkin Solar Farm, LLC	DEC	NC2016-02858
Vintage Solar 2, LLC	DEP	NC2016-02897
Longleaf Pine Solar, LLC	DEC	NC2016-02922
Plott Hound Solar, LLC	DEP	NC2016-02886
Old 421 Solar, LLC	DEC	SP-8291, Sub 0 (no queue number available)

***Cooperative Solar LLC**, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____

Cullen Morris
Manager

Date: 01/31/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Thunderhead Solar, LLC	DEP	NC2017-03088
Ridgeback Solar, LLC	DEP	NC2017-02998

Solterra Partners, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____

Dennis A. Richter
Manager

Date: 1/31/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Overman Solar, LLC	DEP	CHKLIST 9402

ESA Princeton 2 NC, LLC, on its own behalf and in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below

By: _____
Justin Gravatt
Authorized Representative

Date: February 1, 2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
ESA Princeton 2 NC, LLC	DEP	CHKLIST#8484

Robert Cox, *signing as Manager in his authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____

Name: Robert Cox

Title: Manager

Date: 1/31/18

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Monroe Solar, LLC	DEC	NC2015-00011
Harding Solar, LLC	DEP	NC2016-00008
Van Buren Solar, LLC	DEP	NC2015-00020

Andrew Giraldo, *signing as Manager in his authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____

Name: Andrew Giraldo

Title: Manager

Date: 1/31/18

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Harrison Solar, LLC	DEP	NC2015-00019
John Quincy Solar, LLC	DEC	NC2015-00016

Jesse Montgomery, *signing as Manager in his authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____

Name: Jesse Montgomery

Title: Manager

Date: 1/31/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Hayes Solar, LLC	DEC	NC2015-00015
Madison Solar, LLC	DEC	CHKLIST-10194

North Carolina Solar Development, LLC, *in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: Jesse Montgomery

Name: Jesse Montgomery

Title: Manager

Date: 1/31/2018

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Adams Solar, LLC	DEC	CHKLIST-10177
Washington Solar, LLC	DEC	CHKLIST-10217

Current Energy Group, LLC, *in its authorized capacity on behalf of the Settling Interconnection Customer(s) identified below*

By: _____

Name: Robert Cox

Title: Manager

Date: 1/31/18

Interconnection Customer:	**Interconnecting Utility:**	**Queue Number:**
Hickory Solar, LLC	DEP	CHKLIST-7953
Poplar Solar, LLC	DEP	CHKLIST-7954

Contents

1 DEC and DEP obligations 3

2 Interconnection to the transmission system or distribution system 4

2.1 Interconnection method as dictated by DER capacity 4

2.1.1 Consideration of individual DER capacity 4

2.1.2 Consideration of aggregate utility-scale DER capacity (per distribution circuit and per retail substation) 6

2.2 Interconnection to a general distribution circuit: method “D” 7

2.2.1 Considerations & alternatives 7

2.2.1.1 System upgrades: distribution and retail substation 7

2.2.1.2 Alternatives when facilities cannot be further upgraded 7

2.3 Interconnection: direct connection to a retail substation: method “S” 8

2.3.1 Limiting impacts to the transmission system 8

2.3.2 Considerations & alternatives 8

2.3.3 Special notes 9

2.4 Interconnection to the transmission system: method “T” 10

3 Other interconnection project study and design guidelines 11

3.1 Applicability of double circuits for DER 11

3.2 Interconnection locations beyond line voltage regulators (LVRs) 12

3.2.1 DEC and DEP: “Planned” LVR locations previously identified 12

3.2.2 DEP only: continuous system maintenance of DSDR circuit voltage criteria 13

3.2.3 Smart Inverter functionality 13

3.2.4 Clarifications on “partial double circuits” 13

3.2.5 Certain DERs exempt 14

3.3 Line extensions on new ROW 15

3.3.1 Distribution line construction and ownership by private entities 15

3.4 Circuit Stiffness Review (CSR) screen & evaluation 16

3.4.1 Exempted projects 17

3.4.2 Evaluation criteria & methodology 17

3.4.2.1 POI stiffness evaluation 17

3.4.2.2 Substation bus stiffness evaluation 18

4 Glossary of terms 19

5 Revision history 20

1 DEC and DEP obligations

DEC and DEP (Companies) comply with their interconnection obligations under PURPA[1] and applicable state laws by adhering to the North Carolina Interconnection Procedures approved by the North Carolina Utilities Commission (effective May 15, 2015, Docket No. E-100, Sub 101, the "NCIP")) and the South Carolina Generator Interconnection Procedures approved by the South Carolina Public Service Commission (effective April 24, 2016, Case No. 2015-362-E, the "SCGIP")). Consistent with those standards and procedures, the Companies determine and apply technical interconnection guidelines through the administration of Good Utility Practice.[2]

DEC and DEP consider all necessary system upgrades to the general electrical system that are required in order to provide distributed energy resources (DER) reasonable and non-discriminatory access to the DEC and DEP distribution systems, the primary purpose of which is to serve existing and future retail customers. As firm retail electric providers, DEC and DEP seek to interconnect DER in a manner that allows each resource to operate within its contractual parameters without negatively impacting existing utility customers' quality of service or cost of service. DEC and DEP are not, however, obligated under the NCIP or SCGIP to make modifications that are, or reasonably could be determined to be, detrimental to the operation of its system or detrimental to DEC's and DEP's public service obligations as regulated public utilities or retail electric service providers.

[1] Public Utility Regulatory Policy Act of 1978.

[2] Good Utility Practice is defined in the NCIP and SCGIP as any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

2 Interconnection to the transmission system or distribution system

2.1 Interconnection method as dictated by DER capacity

2.1.1 Consideration of individual DER capacity

In most cases, the electrical size (in MW) of a generator interconnection is the primary consideration, all factors considered, as to whether it makes sense to interconnect to the distribution system or to the transmission system. This section's guidelines are intended to more quickly guide interconnection projects to the proper method of interconnection and system at which to interconnect, based on a consideration of the factors involved: (1) impacts to transmission & distribution system reliability/power quality, (2) operational ease and flexibility for the utility, and (3) overall cost (in general, project developers bear all or most up-front costs). Exceptions can be made, but only when a specific project's characteristics and impacts do not fit well into these guidelines, and the optimal balance of factors are the primary consideration.

Table 1 provides general guidance as to the proper method of interconnection.

TABLE 1: Interconnection method based on size of facility

Interconnection method	Interconnection facility (MW) (lower limit)	Interconnection facility (MW) (higher limit)	Guideline for system/ interconnection point
T[3]	> 20 MW	--	transmission system
S	> 10 MW (25 kV or 35 kV class) > 6 MW (15 kV class) > 3 MW (where local retail distribution substation is served from 44 kV sub-transmission)	≤ 20 MW	direct connection to a retail substation[4]
D	--	≤ 10 MW (25 kV or 35 kV class) ≤ 6 MW (15 kV class) ≤ 3 MW (where local retail distribution substation is served from 44 kV sub-transmission) ≤ 2 MW (5 kV class)[5]	general distribution circuit

[3] Method "T" interconnections are specifically guided by DEC's or DEP's appropriate FCR (Facility Connection Requirements) documents, which are accessible at DEC's and DEP's OASIS sites (oasis.oati.com/duk/ and oasis.oati.com/cpl/).

[4] In general, due to the existence of legacy terminology across operating areas, a "retail substation" is the term used within DEC to describe a substation which serves general retail distribution loads from circuits connected to the substation's distribution bus. In this document, the term "retail substation" will be used to describe this type of substation, which in DEP is often called a "T/D" or "T to D" substation.

[5] Interconnections at 5 kV, above 2 MW, are not permitted. Such facilities must interconnect at a higher voltage class.

2.1.2 Consideration of aggregate utility-scale DER capacity (per distribution circuit and per retail substation)

Aggregate capacity of distribution-connected utility-scale projects[6], per distribution circuit, shall not exceed the planning capacity of that circuit. Aggregate capacity of distribution-connected utility-scale projects, per retail substation, shall not exceed the capacity of that substation, as defined by the (1) nameplate capacity[7] of the substation transformer bank or (2) the capacity of other substation components, whichever is less.

Calculation of aggregate capacity of DER on a substation or a circuit shall not include the types of facilities shown in Table 2, nor shall interconnection of the following facilities be subject to aggregate capacity limitations on the circuit or substation.

This requirements may change in the future as DER planning guidelines further mature.

TABLE 2: DERs exempt from aggregate capacity limitations on the circuit or substation

	Tariff	Individual DER capacity[8]	Aggregate DER capacity per circuit, segment or regulated zone
Exemption #1	Net Metered	Up to 1 MW	The aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study. The aggregate DER capacity for further regulated zones (beyond any LVRs) is limited to that which does not cause backfeed of the line voltage regulator. [9] [10] [11]
Exemption #2	Sell Excess	Up to 1 MW	
Exemption #3	PPA with co-located load on secondary of transformer	Up to 1 MW	
Exemption #4	PPA, stand-alone	Up to 250 kW[12] [13]	

[6] For the purposes of these requirements, utility-scale projects are defined as utility-scale/sell-all DER which do not meet the "exempt" definitions in Table 2.

[7] For the purposes of this document, "nameplate capacity" refers to the "OA" or "ONAN" rating, typically the MVA rating upon which the transformer percent impedance is based.

[8] If a single-phase DER facility > 20 kW causes unacceptable imbalance on any portion of the distribution circuit, the interconnection may be deemed infeasible for a single-phase interconnection and may be required to alter its design to three phase.

[9] Note that for South Carolina, there are reserved circuit capacities for individual DER ≤ 20 kW, detailed in section 2.1 of the South Carolina Interconnection Standards (effective 4/26/2016). Such DER will be also deemed exempt from all considerations, including backfeed of an existing LVR, and the cost of any associated studies or upgrades for DER included as part of these reserved circuit capacities are the responsibility of DEC and DEP.

[10] DEC and DEP will employ reasonable methods, as determined by internal engineering resources responsible for performing interconnection studies, and subject to change, to identify the high-level potential for backfeed at the time of the interconnection request under review. When such a potential is suspected, a Supplemental Review or System Impact Study shall be performed in order to determine if backfeed may occur under any circuit loading conditions.

[11] When backfeed is identified in the Supplemental Review or System Impact Study, for exempt sites as identified in this table, DEC/DEP Distribution management and DET (Distributed Energy Technologies) management shall be made aware and shall confer and decide as to the proper disposition of the project(s) in question.

[12] "PPA" facilities ≥ 250 kW are considered the low end of "utility-scale" facilities, and, for purposes of these guidelines, present the potential for significant impact on a distribution circuit.

[13] IEEE 1547-2003, section 4.1.6, requires DER ≥ 250 kVA at a single PCC (Point of Common Coupling) to have monitoring provisions for its status, real and reactive power flow and voltage. Duke Energy requires such

2.2 Interconnection to a general distribution circuit: method "D"

This size of interconnection as indicated in Table 1 should generally be accommodated onto the general distribution system, at the most logical interconnection point consistent with optimizing the factors of reliability, operational ease and flexibility for the utility, and overall cost, and subject to other considerations in this document related to distribution interconnections.

2.2.1 Considerations & alternatives

2.2.1.1 System upgrades: Distribution and retail substation

The System Impact Study (SIS) shall identify and detail the electric system impacts that would result if the proposed generating facility were interconnected without project modifications or electric system modifications. The SIS shall evaluate the impact of the proposed interconnection on the reliability of the electric system, including the distribution and transmission systems, if required. The SIS shall include identification of system upgrades required to correct any system problems identified.

When performing a SIS for a method "D" interconnection, DEC or DEP, as applicable, will consider (among other mitigation options) necessary upgrades to existing retail substation facilities, upgraded to their maximum standard design criteria.

For method "D" interconnections, any extension of distribution facilities to connect DER facilities cannot be "dedicated" by their nature and must be constructed consistent with the DEC or DEP Line Extension Plan and with other practices consistent with DEC or DEP standard distribution system design. The interconnection recloser and meter must both be located at the POI (at the point of change in ownership of facilities).

Interconnection Customers can consider constructing their own lines; such lines would be completely owned, operated and maintained by the Interconnection Customer. The POI would remain at the point of change in ownership of facilities.

2.2.1.2 Alternatives when facilities cannot be further upgraded

If local distribution facilities and/or retail substation facilities cannot be sufficiently further upgraded in order to accommodate the proposed generating facility, then the remaining alternative for the Interconnection Customer is:

1. New retail substation (along with necessary transmission facilities to serve the substation) and general distribution facilities, constructed by Duke Energy, to serve the requested point of interconnection. This can only be considered if this would be consistent with area planning needs and any other specific constraints associated with local transmission and distribution infrastructure (which cannot be pre-determined). Distribution lines can also be designed and constructed by the Interconnection Customer, at their option.

monitoring per this capacity criteria, as this size of DER facility is consistent with more noticeable impacts to distribution planning and operations in both DEC and DEP.

2.3 Interconnection: direct connection to a retail substation: method "S"

2.3.1 Limiting impacts to the transmission system

It should be noted that DEC/DEP maintains the right to limit the total number of taps on a transmission line when DEC/DEP has determined they may grow to be too great in number for that transmission line. In such a case, DEC/DEP may propose alterations to the local area transmission infrastructure in order to get back to a higher reliability arrangement, whatever that may be. The options available for facilities within this size range will be highly impacted by the specific transmission & distribution facilities in the area.

These considerations are guidelines; DEC and DEP maintain full discretion as to the ultimate method of interconnection.

2.3.2 Considerations & alternatives

There are three primary methods for interconnections within this category: (1) connection to an existing nearby retail substation, (2) connection to an existing nearby retail substation along with an additional transformer installation, or (3) construction of a new general retail substation:

(1) Connection to an unregulated bus at an existing nearby retail substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. This would involve substation modifications, and may not always be available if (a) there are no available breaker positions, (b) if some breaker positions are in place for area load growth, or (c) where substation rebuild options do not include the establishment of an accessible unregulated bus. The assessment of the feasibility of this overall method and its options are at the discretion of transmission planning, substation engineering, and/or distribution planning. If this method is not deemed feasible, then the remaining two options below can be considered.

(2) Connection to a new unregulated bus established with an additional substation transformer at an existing substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. (Note: such an expansion shall be built to normal general retail substation standards, only where a second transformer and distribution voltage shall match that of the local operating voltage of the surrounding circuits so that the substation transformer could remain possibly available for general distribution load currently or in the future if the DER facility were to shut down. Essentially this should be treated like a normal substation expansion with an additional transformer, assuming such expansion can be feasibly done.)

(3) Connection to a new unregulated bus established at a new retail substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. (Note: such a substation shall be built to normal general retail substation standards, and distribution voltage shall match that of the local operating voltage of the surrounding circuits so that the substation transformer could remain possibly available for general distribution load currently or in the future if the DER facility were to shut down.) In such a situation, note that transmission system reliability considerations may require alterations or reconfigurations to the local transmission system infrastructure, at the generator's cost, in order to maintain overall system reliability.

2.3.3 Special notes

(1) For method "S" interconnections, extension of distribution voltage class lines from the POI back to substation facilities shall be dedicated by nature, meaning that they are only in place to serve one or more DER interconnections. While Duke Energy can offer to construct such dedicated lines, the Interconnection Customer can also elect to construct a portion or all of the line required.

(2) Note that any DER-dedicated Duke-owned distribution circuit would be likely limited in capacity to no more than 600 amps, and possibly less, due to prevailing available construction methods on general distribution. This could limit 15 kV class interconnection capacity to ~13 MW or less, and could present unique challenges in connecting facilities in the approximate range of 13 MW to 20 MW when substation designs must utilize 15 kV class due to the prevailing distribution voltages in the area.

(3) DER-dedicated circuits constructed and owned by Duke Energy and installed for generation may be built to slightly different standards than conventional "greenfield new general distribution circuits," if their design allows more capacity by slight changes such as increased pole height (with associated increased phase to neutral spacing) and/or reduced span lengths. In no case should the circuit design parameters exceed the ability for Duke Energy distribution field crews to maintain the line. This means that pole height, conductor size, etc., must be maintained within expected usual maximums for distribution field crews to be able to provide effective maintenance services.

(4) At the discretion of transmission and/or distribution planning, an interconnection directly to an unregulated bus can be required to be set at (a) fixed power factor, at unity or off of unity, or (b) active voltage regulation.

2.4 Interconnection to the transmission system: method "T"

Note: method "T" interconnections are specifically guided by DEC's or DEP's appropriate FCR (Facility Connection Requirements) documents, which are accessible at DEC's and DEP's OASIS sites (oasis.oati.com/duk/ and oasis.oati.com/cpl/).

3 Other interconnection project study and design guidelines

3.1 Applicability of double circuits for DER

In general, construction of full or partial "double circuits" (multiple three-phase circuits on one set of poles in a single right of way (ROW)) for line extension to a DER site is not considered Good Utility Practice, whether the consideration is the location of line voltage regulators (LVRs) or some other factor. The inherent ROW present for a second circuit in an existing single-circuit line is a key part of DEC's and DEP's area planning approach for the transmission & distribution system, as part of the Companies' continuous obligation to serve current and future retail customers. Any double-circuiting of an existing single-circuit line must be installed only as part of a comprehensive long-term plan to serve area load. Such double-circuiting cannot be installed solely as a DER interconnection solution, as doing so would impair DEC's and DEP's area planning obligations.

3.2 Interconnection locations beyond line voltage regulators (LVRs)

DEC and DEP have identified that interconnection of uncontrolled[14] utility-scale[15] generation resources with no dependable capacity,[16] at locations beyond LVRs and in high quantities across an entire system, is not consistent with Good Utility Practice. At high quantities across an entire system, facilities with the aforementioned attributes are more naturally adapted to the first zone of regulation outside the substation. Interconnection of such facilities beyond LVRs will likely require non-standard LVR settings, which can (1) limit the switching flexibility of the distribution system, (2) inhibit the effective management of circuits in certain operating areas if regulator control technologies for backfeed are not yet an accepted and tested practice, and/or (3) negatively impact the measured effectiveness of some volt/var control systems such as DEP's DSDR[17] system. Alternatively, interconnection of such facilities beyond LVRs will likely require operation of generating facilities in a reactive power absorption mode, which is not compatible with some volt/var optimization systems and would require further consideration for the impacts to the transmission system if done at wide scale. Therefore, DEC and DEP have established technical guidelines that restrict location of uncontrolled utility-scale generation with no dependable capacity, as referenced and defined above, to the first regulated zone of distribution circuits (substation bus regulation or circuit exit regulation).

3.2.1 DEC and DEP: "Planned" LVR locations previously identified

In some cases, a DEC or DEP Distribution Capacity Planning five-year load-growth study may have already been performed and completed (without having yet been field implemented) prior to the date the Interconnection Customer executes the SIS Agreement to initiate the SIS. In such cases, if such Capacity Planning study had identified changes in LVR placement on the circuit, the planned LVR placement(s) for the circuit (rather than what is currently installed) will be included as part of the SIS. Interconnection locations beyond such planned LVRs will be considered equivalent to interconnection locations beyond existing LVRs. Upon request, DEC or DEP will provide a load-growth study summary with the recommended planned LVR location to the DER interconnection customer.

If no such planning study recommendation pre-dates the initiation of the SIS, and there are no LVR placement changes identified as part of DSDR continuous system maintenance (DEP only, see below), the SIS will only consider the location of any existing LVRs as part of the project study.

[14] "Uncontrolled" means that the facility output (MW) is not capable of being dispatched in a throttled manner by the grid operator.
[15] For the purposes of this document, "utility-scale" generally refers to stand-alone generation facilities (not directly co-located with load) 250 kW or larger.
[16] "No dependable capacity" means that the facility cannot be relied upon for production of a value of capacity (MW) for a specified period or when dispatched.
[17] Distribution System Demand Response.

3.2.2 DEP only: continuous system maintenance of DSDR circuit voltage criteria

The DSDR system in DEP requires adherence to specific circuit voltage criteria in order to maintain system performance. The condition of the circuit and its ability to meet the needed voltage criteria is reviewed as part of the Companies' distribution planning function, whether it is for a regular capacity planning study, for addition of a large "spot load" (commercial or industrial customer), or any other reason to study a circuit.

If during the SIS (the scope of which considers voltage levels on the entire circuit) there is a need identified for LVR placement changes in order to maintain DSDR system performance, the SIS shall include such LVR placement changes and associated cost responsibility in its scope. The cost of such LVR placement changes will only be cost assigned to the interconnection customer if the interconnection creates the need for the LVR placement changes.

Any LVR placement change(s) identified for the circuit (rather than what is currently installed) will be included as part of the assumed "current condition of the circuit" when the SIS if performed. Interconnection locations beyond the LVRs identified pursuant to this subsection will be considered equivalent to interconnection locations beyond existing LVRs, and the study will treat the identified LVR as an existing LVR under these guidelines. Upon request, DEP will provide a study summary with the required LVR placement changes to the DER interconnection customer.

3.2.3 Smart Inverter functionality

It is important to note that at this time DEC and DEP do not assume that generating facilities are capable of modification(s) to their operating characteristics (e.g., "smart inverter functions" such as volt-watt functions, voltage regulation functions, etc.). These modified operating characteristics are under consideration for future adoption by DEC and DEP, but are still considered technologies not yet fully embraced by industry standards and not yet as widely accepted Good Utility Practice. Moreover, use of these functions involves many other considerations, such as impacts to energy production (which in turn has contractual impacts), additional protection & control requirements, utility-to-customer control interface requirements, etc.

3.2.4 Clarifications on "partial double circuits"

When considering the restriction of connection of certain generating facilities below LVRs, it may appear that construction of a "partial double circuit" from the generation site back up to a location ahead of the LVR would facilitate the interconnection. However, as discussed above, the inherent ROW present for a second circuit in an existing single-circuit line is a key part of DEC's and DEP's area planning approach for their transmission & distribution systems, as part of the Companies' continuous obligation to serve current and future retail customers. Any double-circuiting of such a line can only occur as part of a comprehensive plan to serve area load, and cannot be installed solely an incremental consideration for an interconnection project.

3.2.5 Certain DERs exempt

It is important to note that certain DER sites are exempt from restriction to the first regulated zone of distribution circuits, and are therefore allowed to locate beyond LVRs:

TABLE 3 – DERs exempt from LVR guidelines

	Tariff	Individual DER capacity[18]	Aggregate DER capacity per circuit, segment or regulated zone
Exemption #1	Net Metered	Up to 1 MW	The aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study. The aggregate DER capacity for further regulated zones (beyond any LVRs) is limited to that which does not cause backfeed of the line voltage regulator. [19] [20] [21]
Exemption #2	Sell Excess	Up to 1 MW	
Exemption #3	PPA with co-located load on secondary of transformer	Up to 1 MW	
Exemption #4	PPA, stand-alone	Up to 250 kW[22] [23]	

[18] If a single-phase DER facility > 20 kW causes unacceptable imbalance on any portion of the distribution circuit, the interconnection may be deemed infeasible for a single-phase interconnection and may be required to alter its design to three phase.

[19] Note that for South Carolina, there are reserved circuit capacities for individual DER ≤ 20 kW, detailed in section 2.1 of the South Carolina Interconnection Standards (effective 4/26/2016). Such DER will be also deemed exempt from all considerations, including backfeed of an existing LVR, and the cost of any associated studies or upgrades for DER included as part of these reserved circuit capacities are the responsibility of DEC and DEP.

[20] DEC and DEP will employ reasonable methods, as determined by internal engineering resources responsible for performing interconnection studies, and subject to change, to identify the high-level potential for backfeed at the time of the interconnection request under review. When such a potential is suspected, a Supplemental Review or System Impact Study shall be performed in order to determine if backfeed may occur under any circuit loading conditions.

[21] When backfeed is identified in the Supplemental Review or System Impact Study, for exempt sites as identified in this table, DEC/DEP Distribution management and DET (Distributed Energy Technologies) management shall be made aware and shall confer and decide as to the proper disposition of the project(s) in question.

[22] "PPA" facilities ≥ 250 kW are considered the low end of "utility-scale" facilities, and, for purposes of these guidelines, present the potential for significant impact on a distribution circuit.

[23] IEEE 1547-2003, section 4.1.6, requires DER ≥ 250 kVA at a single PCC (Point of Common Coupling) to have monitoring provisions for its status, real and reactive power flow, and voltage. Duke Energy requires such monitoring per this capacity criteria, as this size of DER facility is consistent with more noticeable impacts to distribution planning and operations in both DEC and DEP.

3.3 Line extensions on new ROW

In situations where a line extension is necessary, such as when a DER is located beyond an existing LVR, or is simply located far from existing facilities, DEC or DEP will propose construction of a line extension to connect the site to the circuit at the most logical point on the circuit considering reliability, voltage, capacity, operational considerations, and cost, consistent with Good Utility Practice.[24] DEC or DEP will be responsible for design and construction of the non-dedicated (method "D") or DER-dedicated (method "S") line. The POI will be at the point of change in facilities ownership (at the generator site). DEC or DEP must initially attempt acquisition of ROW. In the event DEC or DEP are unable to acquire ROW during the Facilities Study design process, DEC or DEP will advise the DER owner to assume the obligation for ROW acquisition. Any such ROW shall comply with applicable DEC and DEP ROW specifications.

3.3.1 Distribution line construction and ownership by private entities

If the DER owner requests to build, own, and maintain the line from the circuit tap (as decided by DEC or DEP) to the DER, DEC or DEP will allow the DER owner to pursue this option. In such a situation, the POI will be at the point of change in facilities ownership, at the circuit tap. The DER owner is required to always build all medium voltage (MV) facilities (> 600 volts AC) with DEC/DEP construction and ROW specifications used as the minimum design standard, and all DER owner-constructed-and-owned MV facilities will be inspected by DEC/DEP or its authorized inspection contractor.

[24] If an LVR location is the consideration, the circuit "tap" will be ahead of the LVR location, along with all of the other considerations stated.

3.4 Circuit Stiffness Review (CSR) screen & evaluation

As part of the interconnection process, the SIS is designed to analyze the impact of interconnecting the proposed facility on electric system reliability and the potential for negative impacts to other customers on the system. Effective for all distribution system interconnection requests (except for those noted in the "exemptions" section), Duke Energy will identify (1) areas of high penetration/low grid stiffness[25] through a stiffness factor evaluation, in order to assure that the location of future interconnections do not detrimentally impact power quality and grid operations.

The stiffness factor takes into account the actual equivalent system impedance at the point of interconnection and the relative size of the generation source. It is intended to be an indicator of the potential impacts an individual project may have on the system voltage variability, harmonics impacts, and other related items at its point of interconnection in light of the strength or weakness of the system at that point. A small ratio indicates that the project individually represents a relatively large share of the total short circuit capability at the project site and, by inference, may have an outsized influence at that location across a number of factors. A low stiffness factor will also accentuate local impacts and can cause inverters to be sensitive to normal distribution system operations, such as capacitor bank operations.

The stiffness factor criterion also helps to evaluate the potential for unknowns that may occur in "high penetration" scenarios of utility-scale facilities on the localized distribution system. As of mid-2016, industry technical standards have not yet been developed for high penetration of large distributed generators and North Carolina is seemingly unique in the level of large utility-scale interconnections (especially at 5 MW) interconnecting to the rural distribution system. Such facilities are not necessarily designed for high penetration/low stiffness interconnections, especially when such facilities cannot yet be expected to operate in a voltage regulating mode.[26]

At this time, failure of the CSR evaluation screen is simply designed to trigger a slightly more rigorous study into two types of harmonics: steady-state harmonics and the transient impacts of transformer energization (when the DER facility connects back to the circuit after any time it has been disconnected). This is known informally as "Advanced Study" and is part of the overall SIS (System Impact Study) process.

[25] Stiffness factor, also known as "stiffness ratio," is defined in IEEE Std 1547.2™-2008, IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems: "The relative strength of the area EPS at the PCC compared with the DR, expressed in terms of the short-circuit kilovolt-amperes of the two systems. The general term "stiffness" refers to the ability of an area EPS to resist voltage deviations caused by DR or loading."

[26] Integrated volt/var control systems are not yet compatible with DER operation in a voltage regulating mode. Also, industry practices involving DER operation in a voltage regulating mode, on the distribution system, are clearly not mature at this time. The current IEEE 1547 standard generally prohibits such practice.

3.4.1 Exempted projects

In general, the following situations are to be exempted from the stiffness evaluation:

TABLE 4 – DERs exempt from CSR evaluation

	Tariff	Individual DER capacity
Exemption #1	Net Metered	Up to 1 MW
Exemption #2	Sell Excess	Up to 1 MW
Exemption #3	PPA with co-located load on secondary of transformer	Up to 1 MW
Exemption #4	PPA	Up to 1 MW[27]

3.4.2 Evaluation criteria & methodology

Proposed generator interconnection requests will be reviewed at the outset of the Section 4.3 SIS process to determine whether the project can (1) achieve a minimum POI "stiffness factor" of 25 (as further described below) and (2) achieve a minimum substation "stiffness factor" of 25 (as further described below), in order to pass this screen.

This stiffness evaluation will be performed at two locations – at the POI and at the substation.

3.4.2.1 POI Stiffness Evaluation

At the POI, this evaluation will be performed. A POI Stiffness Factor of exactly 25 or greater (no rounding) for the individual site will be considered as a "pass" for this screen.

$$\text{POI Stiffness Factor} = \frac{\text{Short circuit availability at POI (MVA) without any DER contribution}}{\text{specific DER facility maximum export (MW)}}$$[28]

EXAMPLE: A 5 MW DER requests to interconnect on a 12.47 kV feeder.[29] The available fault current at the planned POI, at 12.47 kV, is 6,500 amps. The POI Stiffness Factor is:

$$SF_{POI} = \frac{\sqrt{3} \times 12.47 \times 6500 \div 1000}{5} = 28.08$$

28.08 > 25, so this would pass the "POI" portion of the CSR screen.

NOTE: POI Stiffness shall be calculated at the POI (high-voltage side of transformer) for utility-scale DER with a single transformer dedicated to the facility.

[27] The impacts of switching large blocks of transformer capacity onto the utility system are more of an issue when interconnection reclosers are present, which is generally for DERs ≥ 1 MW. Since this is the primary issue of concern studied when the CSR evaluation indicates lower stiffness, CSR does not have to be evaluated for DERs < 1 MW.

[28] The value of the DER capacity shall be the Requested Maximum Physical Export Capability at the POI.

[29] Note that the exact nominal distribution voltage should be used in the calculation of utility short-circuit MVA.

3.4.2.2 Substation bus Stiffness Evaluation

In addition, a separate evaluation will be performed at the substation bus with respect to all utility-scale DER connected to the substation, including the proposed DER. A substation bus stiffness factor of exactly 25 or greater (no rounding) will be considered as a "pass" for this screen.

$$\text{Substation Stiffness Factor} = \frac{\text{Short circuit availability at substation bus (MVA) without any DER contribution}}{\text{Total facility maximum export,connected beyond substation (MW)}^{30}}$$

EXAMPLE: A 5 MW DER wants to interconnect on a 12.47 kV feeder. There is already 2 MW of utility-scale DER off of this substation. The available fault current at the substation bus, at 12.47 kV and without contribution from DER, is 8,000 amps. The Substation Stiffness Factor is:

$$SF_{substation} = \frac{\sqrt{3} \times 12.47 \times 8000 \div 1000}{7} = 24.68$$

24.68 < 25, so this would not pass the "Substation" portion of the CSR screen.

[30] The value of the total DER capacity beyond the substation shall be the sum of the Requested Maximum Physical Export Capability for all non-exempt DER sites.

4 Glossary of terms

Non-dedicated distribution line or circuit: This is a distribution circuit which is designed to serve any common class of distribution customer: residential, commercial, industrial and DER. Such a circuit must be designed to +/- 5% voltage so as to assure that existing or future residential customers are assured of proper voltage levels.

DER-dedicated distribution line/circuit: In the context of this document, this refers to a distribution voltage class circuit that is built strictly for DER facilities; no other class of customer is to be located on this circuit. Such a circuit is allowed to be designed to +/- 10% voltage and can be used for DER interconnections only. Due to the unique nature of DER and the flows on this line, this line shall NOT be used for commercial or industrial customers (who normally might be tolerant of +/- 10% voltage).

5 Revision history

Revision	Date	Comments
1.0	9/11/2017	Initial release
1.1	9/20/2017	(a) Clarified that "S" interconnection is inclusive of 20 MW; "T" interconnection is for > 20 MW. (b) Changed Table 4 to indicate that sites are exempt from CSR evaluation below 1 MW. (c) Changed header title to read "DEC & DEP: Distributed Energy Resource (DER) Planning & Interconnection guidelines for DER no larger than 20 MW."
1.2	10/13/2017	Changed document title to "DEC & DEP: October 2017 Distributed Energy Resource (DER) Method Of Service guidelines for DER no larger than 20 MW." Also, "MVA" changed to "MW" in Table 1, as this is mostly a distribution system document, and this MW value is the value that corresponds to the Maximum Physical Export Capability Requested in the Interconnection Request.
1.21	11/01/2017	Clerical and grammatical errors addressed.

Sub 136 DEP Covered Projects that can be connected using existing transformer capacity at or below midpoint rating(133% of ONAN)
7 Projects

Queue Number	Nameplate MW AC	Substation
CHKLIST-8140	5	WEATHERSPOON 230KV
CHKLIST-8849	2	SNOW HILL 115KV
CHKLIST-9211	4.999	CANDOR 115KV
CHKLIST-10362	2	FOUR OAKS 230KV
NC2016-00057	4.95	CHOCOWINITY 230KV
NC2017-03062	1	GLOBAL TRANSPARK 115KV
NC2017-03040	1	LOUISBURG 115KV

Sub 136 DEP Covered Projects exceeding the transformer midpoint (133% of ONAN) up to 167% of ONAN
13 Projects

Queue Number	Namplate MW AC	Substation
CHKLIST-7954	4.5	LAGRANGE 115KV
CHKLIST-8484	4.998	PRINCETON 115KV
CHKLIST-8586	4.998	WEATHERSPOON 230KV
NC2016-02831	5	GOLDSBORO LANGSTON 115KV
NC2016-02965	4.95	ROSE HILL 230KV
NC2017-03063	1	GLOBAL TRANSPARK 115KV
NC2017-03050	1	SAMARIA 115KV
NC2017-03055	1	SAMARIA 115KV
NC2017-03058	1	SHANNON 115KV
NC2017-03052	1	SHANNON 115KV
NC2017-03060	1	SHANNON 115KV
NC2017-03061	1	SHANNON 115KV
NC2017-03059	1	ST. PAULS 115KV

Sub 136 DEC Projects below ONAN nameplate rating
34 Projects

Queue Number	Nameplate MW AC	Substation
CHKLIST-2780	5	Old Mtn Rd Ret 1201
CHKLIST-2785	1.589	Big Willow Ret 1201
CHKLIST-2906	4	Ridgeview Ret 1211
CHKLIST-3391	5	Boonville Ret 1202
CHKLIST-3460	5	Newell Ret 2406
CHKLIST-3830	5	Newell Ret 2407
CHKLIST-5922	4	Browns Ford Ret 1207
CHKLIST-9181	1.999	Sumner Ret 1210
CHKLIST-9185	1.55	Kildare Ret 2411
CHKLIST-9293	3.5	Kildare Ret 2411
CHKLIST-9513	5	Riverstone Ret 1201
CHKLIST-10524	1.137	Clemmons Ret 1210
NC2015-00022	1.999	Parkway SS 1212
NC2015-00053	4.999	Ruffin Ret 1201
NC2016-02776	5	Climax Ret 1204
NC2016-02783	5	Cleveland Ret 1205
NC2016-02814	5	Clemmons Ret 1208
NC2016-02834	4	Swepsonville Tie 1204
NC2016-02861	4.992	Triplett Ret 1208
NC2016-02877	5	Turnersburg Ret 1202
NC2016-02900	4.992	Madison Ret 1208
NC2016-02939	5	Summerfield Ret 2410
NC2016-02951	5	Haw River Ret 1202
NC2016-02975	5	Ragsdale Ret 2408
NC2016-02978	4	N/A
NC2017-03036	1.109	Majolica Rd Ret 1211
CHKLIST-10045	0.35	Park Rd Ret 1214
CHKLIST-10047	1	Coffey Creek Ret 2411
CHKLIST-10473	0.85	Julian Rd Ret 1206
CHKLIST-9968	0.98	Kildare Ret 2406
NC2016-02947	0.286	Salisbury Main 1206
NC2017-03041	0.999	Faith Ret 1204
NC2017-03042	0.999	Faith Ret 1203
NC2017-03046	1	McGinnis Crossroads 1201

Sub 136 DEP Projects below ONAN nameplate rating
44 Projects

Queue Number	Nameplate MW AC	Substation
CHKLIST-7767	1.5	CATHERINE LAKE 230KV
CHKLIST-7953	5	ROSE HILL 230KV
CHKLIST-8122	5	PITTSBORO 230KV
CHKLIST-8611	4.998	HAMLET 230Kv
CHKLIST-8848	2	WALLACE 115KV
CHKLIST-8850	2	CLINTON FERRELL ST. 115KV
CHKLIST-8883	2	ERWIN 230KV
CHKLIST-9024	2	GOLDSBORO LANGSTON 115KV
CHKLIST-9046	1.998	OXFORD NORTH 230KV
CHKLIST-9054	4.999	ERWIN 230KV
CHKLIST-9139	1.998	KINSTON 115KV
CHKLIST-9156	2	GOLDSBORO LANGSTON 115KV
CHKLIST-9355	4.34	BENSON 230KV
NC2015-00005	1.999	WHITEVILLE 115KV
NC2015-00031	4.998	WHITEVILLE 115KV
NC2015-00043	4	WHITEVILLE 115KV
NC2015-00055	4.996	BENSON 230KV
NC2016-00004	5	GOLDSBORO LANGSTON 115KV
NC2016-00019	1.98	GLOBAL TRANSPARK 115KV
NC2016-00030	5	RHEMS 230KV
NC2016-00047	4.999	NEW HOPE 115KV
NC2016-02771	5	TROY 115KV
NC2016-02781	4.989	CATHERINE LAKE 230KV
NC2016-02782	4.989	TABOR CITY 115KV
NC2016-02801	5	SWANSBORO 230KV
NC2016-02827	5	LAKE WACCAMAW 115KV
NC2016-02842	4	WHITEVILLE SOUTHEAST REGIONAL PARK 115KV
NC2016-02843	5	NASHVILLE 115KV
NC2016-02856	5	SANFORD DEEP RIVER 230KV
NC2016-02870	5	HOPE MILLS CHURCH ST. 115KV
NC2016-02923	4.992	KINSTON 115KV
NC2016-02930	4.989	SANFORD HORNER BLVD. 230KV
NC2016-02946	4.998	LELAND INDUSTRIAL 115KV
NC2016-02949	5	DUNN 230KV
NC2016-02960	5	ROXBORO 115KV
NC2016-02962	5	ROXBORO SOUTH 230KV
NC2017-02984	5	SWANSBORO 230KV
CHKLIST-7636	0.44	AVERY CREEK 115KV
CHKLIST-9994	0.812	BARNARDSVILLE 115KV
NC2017-03049	1	OXFORD SOUTH 230KV
NC2017-03048	1	RAEFORD 115KV
NC2017-03054	1	RAEFORD 115KV
CHKLIST-9052	0.999	VANDER 115KV
NC2015-00021	0.479	VANDERBILT 115KV

Sub 140 DEP Covered Projects that can be connected using existing transformer capacity at or below midpoint rating(133% of ONAN)
29 Projects

Queue Number	Nameplate MW AC	Substation
CHKLIST-8098	4.998	SAMARIA 115KV
CHKLIST-8105	5	SEAGROVE 115KV
CHKLIST-8126	4.8	YANCEYVILLE
CHKLIST-8480	4.999	WEATHERSPOON 230KV
CHKLIST-8720	5	CASTALIA 230KV
CHKLIST-8767	5	WARRENTON 115KV #1
CHKLIST-8802	5	GRANTHAM 230KV
CHKLIST-8893	4.8	BLADENBORO 115KV
CHKLIST-9196	4.999	LAUREL HILL 230KV
CHKLIST-10361	4.998	HAMLET 230KV
NC2015-00019	5	ROSEBORO 115KV
NC2016-00028	4.998	SHANNON 115KV
NC2016-00050	5	OXFORD NORTH 230KV
NC2016-02778	5	TABOR CITY 115KV
NC2016-02792	5	ROSE HILL 230KV
NC2016-02794	5	GOLDSBORO LANGSTON 115KV
NC2016-02798	5	WHITEVILLE 115KV
NC2016-02805	2	GOLDSBORO LANGSTON 115KV
NC2016-02819	5	DELCO 115KV
NC2016-02822	4.032	BAYBORO 230KV
NC2016-02846	4.992	CATHERINE LAKE 230KV
NC2016-02883	4.992	FREMONT 115KV
NC2016-02891	4.992	NEW BERN WEST 230KV
NC2016-02896	4.992	MT. OLIVE 115KV
NC2016-02910	4.992	BURGAW 115KV
NC2016-02927	4.992	NEWTON GROVE 230KV
NC2016-02928	4.992	WADESBORO-BOWMAN SCHOOL 230KV
NC2016-02929	5	BURGAW 115KV
NC2016-02938	2	NEWTON GROVE 230KV

Sub 140 DEP Covered Projects exceeding the transformer midpoint (133% of ONAN) up to 167% of ONAN
20 Projects

Queue Number	Namplate MW AC	Substation	
CHKLIST-7923	4.999	GODWIN 115KV	
CHKLIST-8624	4.999	MAXTON 115KV	
CHKLIST-8626	4.999	WEATHERSPOON 230KV	
CHKLIST-8658	5	HENDERSON EAST 230KV	
CHKLIST-8659	5	HENDERSON EAST 230KV	
CHKLIST-8719	5	WARRENTON 115KV #1	
CHKLIST-8803	5	CASTALIA 230KV	
CHKLIST-8821	5	SAMARIA 115KV	
CHKLIST-9198	4.999	FAIRMONT 115KV	
CHKLIST-9402	5	GRANTHAM 230KV	
CHKLIST-9505	4.999	FAIRMONT 115KV	
NC2015-00004	2	FAIRMONT 115KV	
NC2015-00020	5	ROSEBORO 115KV	
NC2015-00041	1.99	BEULAVILLE 115KV	
NC2015-00041-1	5	GRIFTON 115KV	
NC2016-00049	5	WARRENTON 115KV #2	
NC2016-02888	4.992	DELCO 115KV	
NC2016-02893	5	HAMLET 230KV	See Note 1
NC2016-02908	4.992	CATHERINE LAKE 230KV	
NC2016-02935	5	WADESBORO-BOWMAN SCHOOL 230KV	

Note 1: NC2016-02893 will benefit from a transformer upgrade at Hamlet 230 Substation later in 2018. At the time that the transformer in-service date can be determined, Duke agrees to incorporate new transformer data into the System Impact Study.

Sub 140 DEC Projects below ONAN nameplate rating
59 Projects

Queue Number	Nameplate MW AC	Substation
CHKLIST-8208	2	Christopher Rd Ret 1201
CHKLIST-9083	4.999	Monticello Ret 1202
CHKLIST-9155	3.02	Kildare Ret 2406
CHKLIST-9218	4.998	Faith Ret 1205
CHKLIST-9703	5	Mt Pleasant Ret 1202
CHKLIST-9734	5	Glenola Ret 1203
CHKLIST-10177	2	Waynick Rd Ret 1201
CHKLIST-10194	2	Mooresboro Ret 1202
CHKLIST-10217	4.8	Waynick Rd Ret 1201
CHKLIST-10523	5	Climax Ret 1201
NC2015-00042	4.996	Oakwood Ret 1208
NC2015-00052	4.999	Dan Valley Ret 1202
NC2015-00056	1.998	Cleghorn SS 1203
NC2016-00016	4.98	Salisbury Main 1207
NC2016-00024	5	Edneyville Ret 1202
NC2016-00026	5	Glenola Ret 1207
NC2016-00038	1.998	Beaver Dam Ret 2405
NC2016-02777	5	Gatewood Ret 1203
NC2016-02795	5	Lawndale Ret 1213
NC2016-02797	5	Macedonia Ret 1201
NC2016-02806	5	East Maiden Ret 1201
NC2016-02808	5	Wentworth Ret 1212
NC2016-02813	4.999	King Ret 1205
NC2016-02817	4.999	Madison Ret 1203
NC2016-02818	5	Elk Valley Ret 1207
NC2016-02821	4.999	Ossipee Dist 1203
NC2016-02826	4.992	Smithtown Ret 1201
NC2016-02840	5	Pleasant Grove Ret 1202
NC2016-02847	4.992	Turnersburg Ret 1203
NC2016-02858	4.992	Yadkinville Ret 1205
NC2016-02865	3	Washburn Ret 1203
NC2016-02887	5	Denton Ret 1211
NC2016-02894	4.492	Advance Ret 1208
NC2016-02901	4.992	Island Ford Rd Ret 1203
NC2016-02904	4.999	Enochville Ret 1201
NC2016-02916	1.998	Crump Rd Ret 1202
NC2016-02921	4.992	Advance Ret 1209
NC2016-02922	4.992	Advance Ret 1209
NC2016-02924	5	Butner Ret 2407
NC2016-02945	4	Swepsonville Tie 1202
NC2016-02948	2.996	Badin Ret 0408
NC2016-02957	1.999	Gilbreath Ret 2405
NC2016-02974	0.99	Old Fort Ret 1202
NC2015-00048	5	Catfish Ret 1201
NC2016-02839		N Gordonton Ret 1202
NC2017-03065	2	Eden
NC2016-02823	4	Blanton Ret 44 kV
NC2015-00011		Dobson Ret 1201
NC2015-00016		Dobson Ret 1201
NC2015-00015		Dobson Ret 1201
CHKLIST-8912	2	Mooresboro Ret
CHKLIST-8881	4.8	Frieden Ret 2405
NC2016-02829	4.999	Saxapahaw Ret 1201
NC2016-02851	4.999	N Gordonton Ret 1202
CHKLIST-9157	4.998	Mocksville Main 2402
NC2016-02828	4.992	Saxapahaw, 44kV
NC2016-02862	4.992	Fall Creek Ret 1201
NC2016-02857	4.992	Cycle Ret 1201
SP-8291, Sub 0	4.999	Dan Valley 100kV Ret

Sub 140 DEP Projects below ONAN nameplate rating
120 Projects

Queue Number	Nameplate MW AC	Substation
CHKLIST-7967	4.95	CANDOR 115KV
CHKLIST-7991	5	CLINTON NORTH 115KV
CHKLIST-8081	3	LILLINGTON 115KV
CHKLIST-8097	4.998	SAMARIA 115KV
CHKLIST-8106	4.998	SILER CITY 115KV
CHKLIST-8118	4.998	WARRENTON 115KV #2
CHKLIST-8121	5	PITTSBORO 230KV
CHKLIST-8135	5	TROY BURNETTE 115KV
CHKLIST-8237	5	DOVER 230KV
CHKLIST-8402	2	WILSON MILLS 230KV
CHKLIST-8408	1.999	WILSON MILLS 230KV
CHKLIST-8576	4.8	PITTSBORO 230KV
CHKLIST-8627	4.5	Rockingham 230KV
CHKLIST-8657	5	KINSTON 115KV
CHKLIST-8677	4.999	OXFORD NORTH 230KV
CHKLIST-8681	5	RAEFORD 115KV
CHKLIST-8717	4.5	DELCO 115KV
CHKLIST-8794	5	GOLDSBORO LANGSTON 115KV
CHKLIST-8820	3	NEW HOPE 115KV
CHKLIST-8827	5	SELMA 230KV
CHKLIST-8906	4	HENDERSON NORTH 115KV
CHKLIST-8908	5	NASHVILLE 115KV
CHKLIST-8910	5	ANGIER 230KV
CHKLIST-9026	4.8	ROXBORO SOUTH 230KV
CHKLIST-9028	5	NEW BERN WEST 230KV
CHKLIST-9055	3.696	MT. OLIVE 115KV
CHKLIST-9062	2	WILSON MILLS 230KV
CHKLIST-9070	2	WILSON MILLS 230KV
CHKLIST-9073	2	WILSON MILLS 230KV
CHKLIST-9261	2	WILSON MILLS 230KV
CHKLIST-9479	4.998	WILSON MILLS 230KV
CHKLIST-9727	4.998	WILSON MILLS 230KV
CHKLIST-9922	4.998	CLINTON NORTH 115KV
CHKLIST-9971	1.998	BENSON 230KV
CHKLIST-10222	1.999	JONESBORO 230KV
CHKLIST-10534	4.8	WHITEVILLE 115KV
CHKLIST-10544	4.8	TABOR CITY 115KV
CHKLIST-10585	5	ELLERBE 230KV
CHKLIST-10607	4.996	WEST END 230KV
CHKLIST-12137	5	BENSON 230KV
NC2015-00009	1.999	WHITEVILLE 115KV

NC2015-00014	5	LAURINBURG CITY 230KV
NC2015-00028-1	4.998	LOUISBURG 115KV
NC2015-00032	1.998	DOVER 230KV
NC2015-00033	5	MT. GILEAD 115KV
NC2015-00034	1.999	SANFORD GARDEN STREET 230KV
NC2015-00035	1.998	ROSE HILL 230KV
NC2015-00040	4.99	ROSEWOOD 115KV
NC2015-00044	4.2	LOUISBURG 115KV
NC2015-00047	1.998	ABERDEEN 115KV
NC2015-00060	4.98	SILER CITY 115KV
NC2015-00064	5	NEW HOPE 115KV
NC2016-00005	5	WALLACE 115KV
NC2016-00008	5	KINSTON 115KV
NC2016-00010	5	RAEFORD 115KV
NC2016-00021	5	CLINTON NORTH 115KV
NC2016-00023	5	LILLINGTON 115KV
NC2016-00025	5	CATHERINE LAKE 230KV
NC2016-00041	5	ELIZABETHTOWN 115KV
NC2016-00042	1.666	EDMONDSON 230KV
NC2016-02775	5	BAYBORO 230KV
NC2016-02780	5	WEST END 230KV
NC2016-02787	5	BAYBORO 230KV
NC2016-02788	5	LITTLETON 115KV
NC2016-02789	1.998	WHITEVILLE 115KV
NC2016-02793	5	LITTLETON 115KV
NC2016-02796	5	WHITEVILLE SOUTHEAST REGIONAL PARK 115KV
NC2016-02803	5	WALLACE 115KV
NC2016-02804	5	CLINTON FERRELL ST. 115KV
NC2016-02809	5	WADESBORO 230KV
NC2016-02810	4.999	ELIZABETHTOWN 115KV
NC2016-02811	5	LAURINBURG CITY 230KV
NC2016-02812	5	MT. OLIVE 115KV
NC2016-02815	5	BENSON 230KV
NC2016-02824	5	WADESBORO-BOWMAN SCHOOL 230KV
NC2016-02825	5	KINSTON 115KV
NC2016-02833	4.992	JONESBORO 230KV
NC2016-02838	4.999	WALLACE 115KV
NC2016-02841	5	WENDELL 230KV
NC2016-02845	5	BELFAST 115KV
NC2016-02849	5	LAURINBURG 230KV
NC2016-02850	5	ROXBORO SOUTH 230KV
NC2016-02852	5	MONCURE 115KV
NC2016-02853	5	ANGIER 230KV
NC2016-02855	5	CLINTON FERRELL ST. 115KV
NC2016-02860	1.999	ARCHER LODGE 230KV
NC2016-02866	5	LIBERTY 115KV
NC2016-02868	5	ROXBORO BOWMANTOWN ROAD 230KV

NC2016-02869	5	ELLERBE 230KV
NC2016-02871	5	SWANSBORO 230KV
NC2016-02872	5	ARCHER LODGE 230KV
NC2016-02873	5	BELFAST 115KV
NC2016-02879	5	LOUISBURG 115KV
NC2016-02880	5	OXFORD SOUTH 230KV
NC2016-02884	4.992	NEW BERN WEST 230KV
NC2016-02885	4.992	HOPE MILLS CHURCH ST. 115KV
NC2016-02886	4.992	NEW BERN WEST 230KV
NC2016-02892	4.992	FARMVILLE 230KV
NC2016-02897	4.992	WADESBORO 230KV
NC2016-02898	5	LILLINGTON 115KV
NC2016-02902	4.992	HOPE MILLS CHURCH ST. 115KV
NC2016-02903	4.992	SWANSBORO 230KV
NC2016-02911	5	NEWTON GROVE 230KV
NC2016-02913	4.992	SWANSBORO 230KV
NC2016-02914	4.992	BUIES CREEK 230KV
NC2016-02917	4.992	VANDER 115KV
NC2016-02925	4.992	KINSTON 115KV
NC2016-02926	4.992	RHEMS 230KV
NC2016-02931	2	ASHEBORO NORTH 115KV
NC2016-02950	3	BUIES CREEK 230KV
NC2016-02954	5	LUMBERTON #2 115KV
NC2016-02955	1.98	DUNN 230KV
NC2017-02998	2	LIBERTY 115KV
NC2016-02820	5	GARLAND 230KV
CHKLIST-10493	4.998	LAURINBURG CITY 230KV
NC2016-02912	5	ASHEBORO NORTH 115KV
NC2016-02956	0.99	ROXBORO 115KV
NC2017-03088	2	ASHEBORO NORTH 115KV
NC2018-03103	3	Mount Olive Industrial 115kV
NC2017-03083	2	Kings Bluff

ATTACHMENT 4

DEP Substations to be reviewed for Substation Work (Applies to DEP Projects between 133% and 167% ONAN)
24 Substations

BEULAVILLE 115KV
CASTALIA 230KV
CATHERINE LAKE 230KV
DELCO 115KV
FAIRMONT 115KV
GODWIN 115KV
GOLDSBORO LANGSTON 115KV
GRANTHAM 230KV
GRIFTON 115KV
HAMLET 230KV
HENDERSON EAST 230KV
LAGRANGE 115KV
MAXTON 115KV
PRINCETON 115KV
ROSE HILL 230KV
ROSEBORO 115KV
SAMARIA 115KV
WADESBORO-BOWMAN SCHOOL 230KV
WARRENTON 115KV #1
WARRENTON 115KV #2
WEATHERSPOON 230KV
GLOBAL TRANSPARK 115
SHANNON 115KV
ST. PAULS 115KV

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Settlement Agreement in Docket No. E-100, Sub 101, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties:

David Drooz, Chief Counsel
Public Staff
North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, NC 27699-4326
david.drooz@psncuc.nc.gov

Peter H. Ledford
NC Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
peter@energync.org

Daniel Higgins
Burns Day and Presnell, P.A.
PO Box 10867
Raleigh, NC 27605
dhiggins@bdppa.com

David Barnes
NCEMPA
1427 Meadow Wood Blvd.
Raleigh, NC 27604
dbarnes@electricities.org

Brett Breitschwerdt
McGuireWoods, LLP
434 Fayetteville Street
Raleigh, NC 27601
bbreitschwerdt@mcguirewoods.com

Charlotte Mitchell
Law Office of Charlotte Mitchell
PO Box 26212
Raleigh, NC 27611
cmitchell@lawofficecm.com

Andrew Fusco
Electricities of NC
1427 Meadow Wood Blvd
Raleigh, NC 27604
afusco@electricities.org

Edward Teague
Blanco, Tackabery & Matamoros, P.A.
PO Drawer 25008
Winston-Salem, NC 27114
cet@blancolaw.com

Margaret A. Force
Attorney General's Office
PO Box 629
Raleigh, NC 27602
pforce@ncdoj.gov

Richard Harkrader
NCSEA
PO Box 6465
Raleigh, NC 27628
rharkrader@mindspring.com

Richard Feathers
NC Electric Membership Corp.
PO Box 27306
Raleigh, NC 27611
Rick.feathers@ncemcs.com

Robert Duke
The Surety & Fidelity Assn. of America
1101 Connecticut Ave
Washington, DC 20036
rduke@surety.org

Sky Stanfield
Shute, Mihaly & Weinberger, LLP
396 Hayes Street
San Francisco, CA 94102
stanfield@smwlaw.com

Adam Foodman
O2 emc LLC
PO Box 1395
Charlotte, NC 28031
adam@02emc.com

Robert L. Ford
NC Poultry Federation, Inc.
4020 Barrett Dr, Ste. 102
Raleigh, NC 27609
rlford@ncpoultry.org

Karen Kemerait
Smith Moore Leatherwood LLP
434 Fayetteville St.
Raleigh, NC 27601
Karen.kemerait@smithmoorelaw.com

Brian Herndon
Strata Solar LLC
50101 Governors Dr Ste 280
Chapel Hill, NC 27517
bherndon@stratasolar.com

Laura Beaton
Shute Mihaly & Weinberger LLP
396 Hayes St
San Francisco CA 94102
beaton@smwlaw.com

Kurt Olson
PO Box 10031
Raleigh, NC 27605
Kurt.j.olson@gmail.com

Lauren Bowen
Peter Stein
SELC
601 W. Rosemary ST., Ste. 220
Chapel Hill, NC 27516
lbowen@selcnc.org
pstein@selcnc.org

Karen Bell
Dominion
PO Box 26532
Richmond, VA 23219
Karen.bell@dom.com

Dayton Cole
Appalachian State Univ.
PO Box 32126
Boone, NC 28608
coledt@appstate.edu

This the 2nd day of February, 2018.

Lawrence B. Somers
Deputy General Counsel
Duke Energy Corporation
P. O. Box 1551 / NCRH 20
Raleigh, NC 27602
Telephone: 919.546.6722
bo.somers@duke-energy.com